FORTIS BC™

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September 24, 2012

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Generic Cost of Capital Proceeding

FortisBC Utilities[1] ("FBCU")

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 1

On August 3, 2012, the FBCU filed its Written Evidence in the Generic Cost of Capital proceeding as referenced above. In accordance with Commission Order No. G-84-12 setting out the Amended Preliminary Regulatory Timetable, the FBCU respectfully submit the attached response to BCUC IR No. 1.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

on behalf of the FORTISBC UTILITIES

Original signed:

Diane Roy

Attachment

cc (e-mail only): Registered Parties

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[1] comprised of FortisBC Inc., FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc.

A. THE APPROPRIATE COST OF CAPITAL FOR A BENCHMARK LOW-RISK UTILITY

1.0 Reference: Context for the GCOC Proceeding

Exhibit B1-9, p. 3; Exhibit B1-9-1, Appendix A-2 DBRS Report February 29, 2012, p. 5

Actual and Allowed ROE

The FBCU are proposing, for the benchmark FEI, a 10.5 percent ROE and maintenance of the current 40 percent equity component in its capital structure.

The DBRS report dated February 29, 2012 shows, annually for the period 2006 to 2011, the actual return on average common equity and the allowed ROE.

1.1 The Earnings and Outlook table in the DBRS report shows that for each year from 2008 to 2011, the actual return on average common equity exceeds the allowed ROE. Please comment whether for those years 2008 to 2011, the FEI was under Performance Based Regulation.

Response:

FEI was under Performance Based Regulation for 2008 and 2009. FEI was under traditional cost of service regulation in 2010 and 2011 and was not under Performance Based Regulation. For a summary of the actual regulated return as compared to the awarded return for the years 2008 through 2011, please see the response to BCUC IR 1.95.1.

1.2 What are the FBCU's views with respect to FEI returning to regulatory review under PBR? If FEI is returned to PBR, would the FBCU change their proposed benchmark ROE for 2013 and beyond? Why or why not?

Response:

FEI would not be opposed to returning to regulatory review under PBR. If FEI is returned to PBR, the FBCU would not change their proposed benchmark ROE for 2013 and beyond. As identified in Appendix H, FEI is facing a number of increasing business risks including market shifts risks and regulatory risks. The business risks that FEI is facing are independent of whether it is under PBR or traditional cost of service regulation. There is also still regulatory risk to the utility in a PBR framework.

2.0 Reference: FBCU Evidence Introductory Chapter

Exhibit B1-9, p. 3

Throughput and Risk

The FBCU state that, "[t]hroughput is the vehicle, from variable rates charged to customers, by which almost all of FEI's investments are recovered. All else equal, if throughput levels decline for whatever reason, FEI's business risk in effect increases."

2.1 Would FEI agree that its risks related to throughput have declined since 2009 due to its rate competitiveness with electricity? For example, FEI is substantially at less risk for a "death spiral" because natural gas is now so much less expensive than BC Hydro's tier 2 residential and commercial rates. Please discuss.

Response:

FEI does not agree that its overall risk related to throughput has declined since 2009. FEI does agree that the current natural gas supply outlook is more favourable than in 2009 as the market has gained greater understanding and certainty on the potential of North American shale gas developments. This in itself has resulted in a lower gas price outlook and improved the natural gas price advantage against electricity on an operating or variable cost basis, all else being equal. However, there are other factors that impact throughput rates where the risks have increased. Please refer to the response to BCUC IR 1.97.1 for a discussion on these factors.

2.1.1 At 2009 and at today's natural gas and electricity Tier 2 rates please provide calculations of how much average natural gas throughput would need to be lost to drive FEI's distribution margin up so that its natural gas rates would become equal to BC Hydro's tier 2 electric rates?

Response:

Table 1 which follows shows the calculations and assumptions used to determine how much natural gas throughput would need to be lost to drive FEI's distribution margin up so that its natural gas rates would become equal to BC Hydro's Step 2 electric rates at 2009 and today's rates.

However, before presenting the results, FEI would like to point out that using the BC Hydro Step 2 rate as the only electricity rate benchmark is inappropriate. As discussed in the response to

BCUC IR 1.98.2, smaller or more energy-efficient dwellings such as townhouses and condominiums may be capable of getting some or all of the energy needed for space and water heating from BC Hydro's Step 1 block. Furthermore, as discussed in Section 5.1 of Appendix H of the Application, natural gas prices are at their lowest levels in over ten years and current forecasts indicate that a tightening of the supply and demand balance will lead to higher prices in the future. With higher natural gas prices and rates, less throughput would have to be lost for FEI's distribution margin to increase so that its natural gas rates became equal to BC Hydro's Step 2 electricity rates.

The following table shows that FEI's natural gas throughput would have to decrease by 76% based on 2009 natural gas and Step 2 electricity rates and by 83% based on today's natural gas and Step 2 electricity rates.

Table 1: Throughput Decrease Required to Increase FEI's Distribution Margin

Line			Residential 2012	Residential 2009
1	Rates			
2	BC Hydro Step 2 ($/GJ)	As at July 1, Converted to $/GJ	26.743	20.882
3				
4	FEI Residential Rates ($/GJ)			
5	Residential Midstream	As at January 1	1.365	1.015
6	Residential Commodity	As at July 1, 2012 & weighted average 2009	2.977	6.103
7	Residential Delivery (excluding Riders) 1		3.488	2.961
8	Residential Daily Basic Charge 2	As at January 1	1.561	1.561
9				
10				
11	Volumetric Delivery Rate Needed	Line 2 - Line 5 - Line 6 - Line 8	20.84	12.20
12	Existing Volumetric Delivery Rate	Line 7	3.488	2.961
13	Increase in Delivery Rate Required	Line 11 - Line 12	17.35	9.242
14				
15	Approved Volumetric Residential Delivery Margin ($000s)	Line 12 x Line 19	243,776	202,820
16				
17	Throughput Required at Revised Volumetric Delivery Rate(TJ)	Line 15 / Line 11	11,697.9	16,621.1
18				
19	Existing Throughput (TJ) 3		69,890.0	68,497.0
20	% of Existing Throughput	Line 17 / Line 19	17%	24%
21				
22	Throughput that would need to be lost (TJ)	Line 19 - Line 17	**58,192.1**	**51,875.9**
23	Throughput that would need to be lost (%)	1 - Line 20	**83%**	**76%**
24				
25	Notes:			
26	1 Delivery margin on which approved rates set			
27	2 Calculated as approved daily basic charge of $0.389 per day x 365.25 days / avg Residential Mainland customer use rate of 91 GJs			
28	3 FEI Rate Schedule 1 Residential Volumes as approved in 2012/2013 RRA			
29	Assumptions:			
30	-No loss in customer counts or basic charges. All change was based on customer use rate decreases			

3.0 Reference: Development since the 2009 Decision

Exhibit B1-9, p. 7

Tone of Equity Market

FEI states that, "In Mr. Engen's opinion, the current tone of the equity markets support an increase in the allowed ROE for the benchmark, FEI."

3.1 The current market seems to have bid up the price/earnings multiples of utilities compared to the overall market. Wouldn't that suggest that a reduction in ROE would be appropriate to bring these multiples back in line with the market? Please discuss.

Response:

The concept of adjusting allowed ROEs to manage utility share prices in such a fashion so as to keep utility price/earnings multiples in line with the market is not feasible nor is it desirable.

To begin with, multiple regulators may be involved with setting allowed ROEs for a corporation's regulated businesses (as is the case with Fortis Inc.). The more a utility's operations are overseen by different regulators, the less ability any one regulator has to effect change in the utility's share price and market valuations.

In many cases rate-regulated, cost-of-service assets comprise only a portion of the utility owner's businesses. The ability to determine which assets, non-regulated vs. regulated, are supporting the higher valuations is, at best, questionable. Were the company's non-regulated operations to be more attractive to the market, the regulator would have to more heavily penalize the regulated assets in order to manage down the company's earnings valuations to offset the positive P/E valuation impact of the non-regulated business.

P/E multiples may change for reasons not connected with allowed ROEs. For example, a company may be expecting material growth in nearer-term earnings which the market is willing to pay for (at least in part) in the current year. In such a case, one would expect the company's P/E ratio to rise and, perhaps, substantially so. In such case, it would be perverse to reduce allowed ROEs in an attempt to lower P/E ratios when the reason they were high in the first instance had nothing to do with allowed ROEs.

Finally, adjusting allowed ROEs to keep P/E multiples in line with the market would result in increased volatility in regulated asset earnings as allowed ROEs are manipulated upwards and downwards. The end result of such an exercise would be to turn regulated asset earnings into assets with the same earnings volatility as the market. Doing so would bring regulated asset risk closer to, if not to, the market's level of risk and result in an increase regulated asset cost of capital.

The issue of the application of per share valuations has been considered before in the context of price to book metrics and has been dismissed by authorities on the regulation of utilities. In 1961, Dr. James Bonbright wrote:

> *"Should the allowed rate of return be designed to prevent the market prices of public utility equities from rising to substantial premiums above book values? A rigorous and literal application of a cost-of-capital measure of a fair rate of return in the above-outlined sense of this measure would mean an attempt by a commission to regulate rates of charge so as to maintain the market prices of utility equities on a par with their book values or rate-base values plus some stipulated allowance for necessary underpricing.* ***Yet a mere reference to any such attempt should suffice to suggest its absurdity.*** *In the first place, commissions cannot forecast, except within wide limits, the effect of their rate orders on the market appraisals of the stocks of the companies subject to these orders. But in the second place, whatever the initial market appraisals may be, they are sure to change not only with the changing prospects of earnings but with the changing outlook of a notoriously volatile stock market. In short, market prices are beyond the control, though not beyond the influence, of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it in the manner just suggested would result in harmful, uneconomic shifts in public utility rate levels…*
>
> *It follows that the common stocks of public companies which actually succeed in earning a "fair rate of return" as derived by a cost-of-capital technique can be expected to command substantial premiums over their book values or rate-base values except in periods of a seriously depressed stock market – premiums well in excess of any customary allowance for the necessary underpricing of new stock offerings. And the question arises whether the prevalence of these excess premiums is persuasive evidence of a corporate earning power higher than enough to give adequate assurance of continued corporate ability to attract the desired amounts of new capital on terms that do not impair the integrity of the existing capital.*
>
> *In my opinion, the answer to this question is in the negative. Regulation is simply powerless to assure the purchasers of public utility equities that future corporate earnings will suffice to maintain market prices on a par with book values or with any other dollar figure. Lacking this power, regulation wisely concedes to the public utility industries opportunities for corporate earnings liberal enough to bring to substantial market premiums the stocks of those well-managed companies that actually succeed in realizing these earnings fairly continuously. But while the allowance of a rate of return, during periods of prosperity, liberal enough to let utility equities command substantial premiums over their book values seems to me to be called for in the interest of long-run corporate ability to meet capital requirements, the question what constitutes a proper degree of liberality has not yet received a convincing answer. Indeed, I doubt whether a conclusive answer can ever be found under such an indefinite standard of a fair rate of*

return as that of a flexible rate designed to rise and fall with changes in anticipated rates of income necessary to induce new investments of equity capital." [1] [emphasis added]

3.2 Please provide the overall TSX market P/E multiples and average utility multiples in 2009 and currently.

Response:

The requested data is provided in the following table.

	S&P/TSX	**Canadian Utilities Group**
September 2009 (average)	17.2x	14.6x
September 2012 (August 14 – September 1 average)	14.8x	24.5x

[1] Bonbright, James C. Principles of Public Utility Rates. New York, Columbia University Press, 1961, pages 254 through 256.

4.0 Reference: Developments since the 2009 Decision

Exhibit B1-9, Section 1.2, pp. 6-8; Exhibit A2-11 Excerpts from FEI 2005 and 2009 Applications

Cost of Capital for Benchmark FEI

The FBCU discuss the changes in the financial markets since 2009 and the impact that it has on the cost of capital. The evidence states that against the backdrop of ongoing market volatility, the risk factors that have influenced the BC utility business in years past remain relevant today.

The FBCU proceed to discuss that Ms. McShane's and Mr. Engen's evidence describes how the capital markets remain in a period of turmoil. In the summary paragraph of Section 1.2, the FBCU states that "the evidence in this Filing demonstrates that the cost of capital for the benchmark FEI is higher than what the Commission allowed in 2009."

4.1 In previous ROE/CAP applications from Terasen Gas Inc. (as FEI was formerly known), the utility presented its weighted equity return component against other utilities. In the 2005 application, it described the "British Columbia penalty" experienced by FEI and in the 2009 ROE application, it described the "basis points disadvantage" of FEI. Please update the two tables in Exhibit A2-11 using the most recent data.

Response:

In 2005 and 2009, TGI had a weighted average basis point disadvantage and penalty relative to its peers, and this was partially addressed in the Capital Structure and ROE decision in 2009 by way of abandoning the formula and increasing the equity component to 40%. FEI notes that the revised tables are not indicative of the differential that exists today given there are several applications pending and new proceedings in 2013 that will be addressing cost of capital, many of which will result in Utilities seeking increases to Equity Thickness and ROE.

2005 Table

	Allowed ROE for 2012 (1)	Common Equity Ratio (2)	Weighted Return Component (1 X 2)
FEI (TGI)	9.50%	40.0%	3.800%
Comparables			
ATCO Gas[1]	8.75%	39.0%	3.413%
Enbridge Gas[2]	8.39%	36.0%	3.020%
Gaz Metro[3]	8.90%	38.5%	3.427%
TransCanada Pipelines[4]	8.08%	40.0%	3.232%
Union Gas[5]	8.54%	36.0%	3.074%
AVERAGE	**8.53%**	**37.9%**	**3.233%**
FEVI (TGVI)	**10.00%**	**40.0%**	**4.000%**
Comparables			
AltaGas[6]	8.75%	43.0%	3.763%
EGNB	10.90%	45.0%	4.905%
Gazifere [7]	8.29%	40.0%	3.316%
Heritage [8]	11.00%	45.0%	4.950%
Natural Resource Gas [9]	9.42%	40.0%	3.768%
AVERAGE	**9.67%**	**42.6%**	**4.140%**

NOTES:
(1) 2013 will be result of new proceeding to be announced soon.
(2) PBR left "base" ROE in rates unchanged since 2007. After earnings sharing, EGD earned 10.5% from 2008 to 2011. While OEB ROE formula changed in 2009, EGD ROE remained unchanged for the 5-year term of the PBR. Likely to be on new formula for 2013, has applied for 42% common equity.
(3) Formula ROE.
(4) Still on old RH-2-94 formula due to settlement through 2012
(5) Similar to EGD; earned 10.9% after sharing from 2008-2011. Settlement for 2013 for new ROE formula, application for 40% equity still to be decided by OEB.
(6) Same as ATCO Gas.
(7) Formula
(8) Negotiated settlement.
(9) OEB formula.

2009 Table

	Current Allowed ROE	Equity Component	Effective Return	Advantage to FEI (bps)
Newfoundland Power [1]	8.80%	44.7%	3.934%	13.4
Maritime Electric	9.75%	40.5%	3.949%	14.9
FEVI (TGVI)	10.00%	40.0%	4.000%	20.0
FortisBC	9.90%	40.0%	3.960%	16.0
Gaz Metro	8.90%	38.5%	3.427%	(37.4)
TransCanada Pipelines	8.08%	40.0%	3.232%	(56.8)
ATCO Gas	8.75%	39.0%	3.413%	(38.8)
FortisAlberta [2]	8.75%	41.0%	3.588%	(21.3)
Westcoast Energy (Spectra) [3]	9.70%	40.0%	3.880%	8.0
Union Gas	8.54%	36.0%	3.074%	(72.6)
Enbridge Gas	8.39%	36.0%	3.020%	(78.0)
FEI (TGI)	9.50%	40.0%	3.800%	-

NOTES:
(1) Negotiated settlement; 2013 cost of capital just filed.
(2) Equity ratio = 39% + 2% for non-taxability during big capital expenditures program.
(3) Multi-year settlement.

4.1.1 Please discuss the "British Columbia penalty" and the "basis points disadvantage" and whether these concepts still exist today.

Response:

Please refer to the response to BCUC IR 1.4.1.

5.0 Reference: FEI as Benchmark Utility

Exhibit B1-9, pp. 9, 17; Exhibit B1-9-6 Appendix F Testimony of Ms. McShane p. 6

Cost of Capital for FEI

The FBCU submit that the appropriate benchmark utility at this time is FEI, with its current characteristics and before any amalgamation takes place. If amalgamation takes place, FEI in its present state can remain as the benchmark utility until the next comprehensive cost of capital review.

The FBCU also submit that FEI is not a "low risk benchmark." FBCU submit that a benchmark need not be "low risk" to be an effective point of comparison for establishing the cost of capital for other BC utilities.

5.1 If FEI is again designated the "benchmark utility" to establish the cost of capital for other BC utilities, does it matter to FEI, the utility itself, whether it is low-risk or not since, in principle, a benchmark is just used to set a baseline ROE?

Response:

Yes, it matters to FEI, the utility, how the utility is characterized. While the presence or absence of the label "low-risk" does not, in principle, affect the determination of the relative risk among the BC utilities, the FBCU regard it as important for the determination of FEI's own cost of capital that it be characterized accurately. FEI is not, in the FBCU's view, the low risk utility either in a BC context or in a broader Canadian utility context.

5.1.1 On page 6 of Ms. Mcshane's testimony in Tab F, it states that the fair return on equity for FEI as the benchmark BC utility was estimated at 10.5 percent based on a 40 percent common equity ratio, and reflects, among others, the application of the comparable earnings test to a sample of relatively low risk unregulated Canadian firms (underline added for emphasis). Please explain what is meant by relatively low risk.

Response:

"Relatively low risk" in the context of the comparable earnings approach means that the selected firms are of lower than average risk relative to the universe of unregulated companies.

5.1.2 If a sample of "low risk" instead of "relatively low risk" unregulated Canadian firms had been used instead, would the return on equity in Table 1 under Comparable Earnings Test of 11.5 percent be lower?

Response:

No. It is the underlying characteristics of the firms, rather than the presence or absence of the label "low-risk" or "relatively low-risk", that informs Ms. McShane's analysis. Please note that, in performing the comparable earnings test, it was explicitly recognized that the sample of companies was of somewhat higher risk than a benchmark BC utility. The resulting comparable earnings ROE incorporates a downward adjustment to recognize the unregulated companies' higher risk.

5.2 DBRS describes FEI's business as low-risk business. Moody's describes FEI as a "low-risk, cost-of-service regulated gas transmission and distribution utility" (Exhibit B1-9-1, Appendix A-2, DBRS February 29, 2012 Rating Report, Moody's Global Credit Research 21 July, 2011). Do the FBCU agree? If not, why not?

Response:

Yes, in the context of the entire universe of rated companies. However, the FBCU do not regard FEI as low risk in the context of the universe of Canadian gas and electric distribution utilities.

5.3 In the view of the FBCU, are there any other utilities in B.C. besides FEI that could also be selected as a benchmark utility and capture the regulatory efficiencies without compromising the Commission's obligation to meet the Fair Return Standard? For example, PNG or FortisBC electric?

Response:

FortisBC Inc. is the only potential alternative, although it is a much smaller utility than FEI. However, as discussed at lines 414-421 of Ms. McShane's evidence, FEI possesses the characteristics that should define the benchmark utility, including the fact that its business risks and the trends in those risks have been extensively and comprehensively assessed by the Commission in multiple proceedings. As a result, the FBCU see no advantages to be gained by designating a different utility as the benchmark.

6.0 Reference: FEI as the Benchmark Utility

Exhibit B1-9, pp. 17, 18; Exhibit A2-12 FEU 2012-2013 RR and Rates Decision pp. 11, 12, April 12, 2012

Utilization and Characteristics of a Benchmark Utility

The FBCU summarize the reasons articulated by Ms. McShane and Dr. Vander Weide as to why an actual utility should be designated as the benchmark utility, rather than relying on a purely hypothetical construct. One of the reasons summarized at a high level is that "designating an actual utility as the benchmark eliminates ambiguity and reduces subjectivity in determining the characteristics of the benchmark, such as its size, scale, geographic scope, competitive position and business risks."

In the April 2012 Decision, the Commission describes FEU as a group of companies in transition; that they have made significant progress in moving away from their traditional roots; that in recent years, the Companies have explored and developed what they believe to be an expanded range of service offerings to satisfy growing needs of the customer base, etc.

6.1 Do the FBCU agree with the description of FEU in the April 2012 RR and Rates Decision? If not, why not?

<u>Response:</u>

No, the FEU do not agree with the description noted above. It is correct that, in recent years, in response to the changing energy environment in BC and the declining throughput levels impacting the FEU's core business, the FEU (mainly FEI) have pursued new initiatives, expanding its range of service offerings. However, at their foundation these offerings make use of natural gas or its established infrastructure. The FEU remain and will remain natural gas distribution utilities whose core business is the transmission and distribution of natural gas to residential, commercial and industrial customers. The NGT and biomethane initiatives are in very early stages of market development, but are service offerings that are part of the core distribution business, with the focus on utilizing FEU's natural gas distribution and transmission system, which provides benefits to existing customers. Thermal Energy Service ("TES") as well are in the early stages of market development and the investment in TES is immaterial relative to the size of the FEU distribution and transmission assets. Furthermore, TES will either be offered as a separate class of service within FEI or by a separate affiliate, and will not be reflected in the profile of the benchmark.

The attributes that make FEI a more appropriate benchmark than a hypothetical entity remain valid even with the potential for business changes over time. The benchmark cost of capital is determined at a point in time, and it is to be revisited over time. Although the profile of the benchmark may change from review to review, the key point is that (unlike a hypothetical utility) its characteristics and risk profile is capable of being ascertained with certainty when it is reviewed.

Page 12 of the April 2012 Decision in Exhibit A2-12 says: The Commission Panel in the 2009 ROE Decision agreed with the Terasen Companies with respect to climate change and energy policies noting "that the introduction of climate change legislation by the Provincial Government has created a level of uncertainty that did not exist in 2005 and that the change in government policy will quite probably cause potential customers not to opt for natural gas and persuade potential retrofitters to opt for electricity."

6.2 Please confirm that the following has taken place in B.C. since the 2009 ROE Decision:

a) the provincial government has issued a new natural gas policy with respect to encouraging LNG for export and the use of natural gas for transportation purposes;

Response:

Confirmed. Please refer to the response to BCUC IR 1.100.2.

b) the gas commodity prices have decreased further and natural gas is competitive with the two-tier residential electricity rate which is forecast to increase significantly?

Response:

The FEU can confirm that natural gas commodity prices have decreased, making it more price competitive with electricity under step 2 on an operating cost basis. Natural gas also competes with step 1 rates (for example it applies to water heating), which is not expected to increase as much as step 2 rates. Capital costs are also a factor in price competitiveness. Please also refer to the response to BCUC IR 1.97.1.

c) FEU have embarked on new business initiatives such as natural gas for transportation, biomethane services, and alternative energy solutions.

If the FBCU are unable to confirm, please describe in the FBCU's own words the above events.

Response:

Confirmed. In recent years, in response to the changing energy environment in BC and the declining throughput levels impacting FEI's core business, FEI has pursued new initiatives such as biomethane services and natural gas for transportation ("NGT"). Thermal Energy Service ("TES") will either be offered as a separate class of service or by a separate affiliate, and will not be reflected in the profile of the benchmark. FEI's core market remains space and water heating, and will remain so for the foreseeable future even in the case where there is significant uptake in biomethane and NGT initiatives. The throughput associated with these initiatives will still be dwarfed in absolute terms by the core market. FEI's overall risk profile is driven by its success in attracting and retaining customers in the traditional space and water heating markets, which remains as a key challenge for FEI. Please also refer to the response to BCUC IR 1.6.1.

7.0 Reference: FEI as Benchmark Utility

Exhibit B1-9, p. 22

FEI Business Risk

FEI states "For instance, FEI is now seeing local governments mandating certain non-natural gas energy solutions as a condition of obtaining municipal approvals for building permits."

Exhibit A2-18 (City of Vancouver's *District Energy connectivity Standards* – Information for Developers, dated November 2011) states the following:

"1. Introduction & Intent

This document summarizes building design strategies required of developers in anticipation of future building connection to a District Energy System (DES). Developers are required to adopt these standards and make appropriate provisions in building mechanical design to enable them to take full advantage of the benefits offered through future DES connection.

Through adoption of these standards the need for future disruptive retrofits to buildings to make them DES-connectible is avoided, thereby reducing future costs of connection and inconvenience to occupants. Compliance with these standards will also act to improve overall building mechanical system efficiency.

2. What Buildings must be Connectable to a DES?

<u>The City has identified high priority areas targeted for future District Energy service based on current density and/or anticipated growth potential. In these cases, the form of development must incorporate a DES-connectable interim approach to space heating and domestic hot water which will require minimal retrofits to connect to a DES in the future</u>. (Emphasis added)

…

4. Requirements for DES-Connectable Hydronic Systems in Buildings

<u>4.1 Overview</u>

<u>For future DES-connectivity, hydronic (hot water) heating systems are required</u> with heating equipment centralized in a common mechanical room located such that connection to the future DES piping system is feasible. The preferred location for the building mechanical room is in the basement, parkade, or ground level. Once a DES is developed, the building mechanical room will become home to the ETS (i.e. the building interface with the DES piping). (Emphasis added)

…

<u>4.3 Hydronic Heating and Domestic Hot Water Systems (Minimum) Requirements</u>

<u>The hot water hydronic heating system shall be designed to provide all of the space heating and ventilation air heating requirements for the individual suites, hallways/stairwells and other common areas in the building, supplied from a central mechanical room within the building.</u>" (Emphasis added)

Exhibit A2-19 (City of Surrey, District Energy System By-law, 2012, No. 17667) requires new high-density developments in the City Centre area to incorporate hydronic space heating and hot water systems and connect to the City's DE system once it is available. There are some concessions for developments that have already been issued development permits and for developments where DE service won't be available in the short-term. Some of these developments will be allowed to incorporate electric resistance heaters but will be required to utilize DE-compatible hydronic system for all domestic hot water and ventilation make-up air.

Section 2.1 of the By-law mandates compulsory use of district energy system and Section 2.2 mandates compulsory hydronic systems. They are reproduced below for ease of reference.

Compulsory use of district energy system

2.1 Each owner in Service Area A of:

(a) a new building with a floor area ratio equal to or greater than 1.0 proposed for construction or under construction for which the Building By-law requires submission of a building permit application and issuance of an occupancy permit to which the owner, as at the date of enactment of this By-law, is not yet entitled; or

(b) an existing building with a floor area ratio equal to or greater than 1.0 where the estimated value of proposed alterations or alterations under construction which require submission under the Building By-law of a building permit application is more than $400,000 and 50% of the building's latest assessed value according to the records of the British Columbia Assessment Authority,

must make use of the district energy system in accordance with the terms and conditions of this By-law.

Compulsory hydronic systems

2.2 Each owner in Service Area B of:

(a) a new building with a floor area ratio equal to or greater than 1.0 proposed for construction or under construction for which the Building By-law requires submission of a building permit application and issuance of an occupancy permit to which the owner, as at the date of enactment of this By-law, is not yet entitled; or

(b) an existing building with a floor area ratio equal to or greater than 1.0 where the estimated value of proposed alterations or alterations under construction which require submission under the Building By-law of a building permit application is more than $400,000 and 50% of the building's latest assessed value according to the records of the British Columbia Assessment Authority,

must utilize hydronic systems that are compatible with the district energy system for all space heating and hot water heating, as described in the City's Design Criteria Manual / Energy Services Design Requirements, and in accordance with those terms and conditions of this By-law stated to be applicable to future designated buildings.

Compulsory hydronic systems where floor area ratio is less than 2.5

2.3 Where a building described in section 2.2(a) or (b) has a floor area ratio of less than 2.5, the owner will not be required to utilize hydronic systems for space heating within individual units, but hydronic systems will be required for all other space heating and hot water heating in the building.

Exhibit A2-20 provides an excerpt of Information Requests and responses between the Commission and River District Energy Limited Partnership regarding the ban on electric baseboard heaters in the Design Guidelines for the River District development located in the City of Vancouver.

7.1 Do the FBCU are aware that the same local governments who are mandating certain non-natural gas energy solutions as a condition of obtaining municipal approvals for building permits are also requiring these new developments/high-rise residential buildings to be District Energy ready, i.e., to utilize hydronic systems that are compatible with DE system?

Response:

The following provides the responses to BCUC IRs 1.7.1 to 1.7.3

Yes, the FBCU are aware that some local governments (such as City of Vancouver and City of Surrey) are establishing by-laws and standards regarding the energy systems that must be used in certain types of developments, such as the cited example of requiring buildings of certain types and in certain areas to be district-energy ready.

The FBCU believe the intent of some of these municipal requirements to install hydronic systems is to either prevent the use of electric baseboard heating or at least enable conversion to alternate technologies other than baseboards in the future. Therefore, it is clear that baseboard heaters are being discouraged.

Of note though, is that natural gas is only one of a variety of fuel sources that are compatible with hydronic systems. Whether natural gas would be used as a transitional fuel source in a district energy system would be dependent on the specifics of the planned district energy system.

Where the district energy system is planned to be an ambient temperature system, using, for example, geo-exchange technology, it is expected that the ambient temperature energy systems would be expanded in stages to match the development phases of the district energy system. In other words, it is expected that the geo-exchange loop-fields and heat pump systems would be built to serve each phase and as a new phase is added the energy system would be expanded to serve the incremental requirements of the new phase. Natural gas boilers may be used in these cases as a back-up or supplementary thermal energy source but this would likely be part of the overall permanent system design, and not as a transitional fuel only.

In situations where the district energy system is planned to be a high temperature system, such as a biomass-based system, the FBCU expect that natural gas boilers would be used to provide the base thermal energy requirements in the transitional period before a district energy system (and the permanent energy solution) is established. This has occurred in BC at district energy systems such Dockside Green, Corix UniverCity and River District Energy. An obvious inference from the fact that natural gas is playing a transitional role in district energy systems of this type is that the natural gas load will be lost (or substantially diminished) when the permanent energy solution is implemented so gas system utilization benefits are temporary or diminishing over the longer term.

In conclusion, while natural gas may be a transitional energy source in some district energy systems, the FBCU do not believe that overall this will be material source of gas load that will reduce the business risk of the gas utilities. Nonetheless, as providers of energy and energy services in British Columbia the FBCU consider it essential to be aware of federal, provincial and municipal regulations and policy developments that will affect the Companies' business going forward. Policies such as these do add a level of uncertainty around natural gas demand.

7.2 Do the FBCU agree that, in instances <u>where DE system are not yet available</u>, the requirement that developers install hydronic systems to provide all of the space heating and ventilation air heating requirements for the individual suites, hallways/stairwells and other common areas in the building in effect discourages the installation of electric baseboard heaters? If not, please explain why not.

<u>Response:</u>

Please refer to the response to BCUC IR 1.7.1.

7.3 Please discuss the energy source options facing developers who must incorporate hydronic systems for space heating and domestic hot water in new residential high-rise developments in anticipation of a DE system which will not be available in the short-term. Do the FBCU agree that natural gas is the preferred fuel source in those circumstances?

Response:

Please refer to the response to BCUC IR 1.7.1.

8.0 Reference: FEI as Benchmark Utility

Exhibit B1-9, p. 23

FEI Business Risk

FEI states “Alternative energy sources continue to pose competitive challenge to FEI.”

8.1 Are alternative energy sources still competitive with current FEI natural gas rates? Please discuss and show cost calculations for various types of alternative energy sources.

Response:

Yes, alternative energy sources can be competitive with natural gas in the market for thermal energy.

Typically, different thermal energy systems that compete with each other, including those that use natural gas as a fuel, will have one of two fundamental sets of characteristics:

1. Lower capital costs but higher fuel consumption
2. Higher capital costs but lower fuel consumption

Fundamentally, competition between fuel sources occurs at the time of building design. The proximity and connection between the thermal energy system and the customer site where thermal energy is being used effectively eliminates competition between fuel sources once the equipment has been selected and installed. In addition, the equipment is usually long-lived. In reality, some fuel sources, once installed, effectively rule out conversion to other fuel sources in the future.

Given the long life span of thermal energy equipment and the potential for high up front capital costs, the choice of fuel source involves an evaluation of the total costs of thermal energy over an appropriate evaluation period, such as twenty years.

Components of the analysis will include:

1. Thermal energy demand,
2. Capital costs of equipment including any planned replacements,
3. Fuel consumption costs,
4. Operating and maintenance costs, and
5. Taxes and depreciation costs

Evaluation of alternatives varies according to the situation and given the vast array of equipment, age of equipment, efficiency of the equipment and potential usage of the equipment, the analysis is ultimately a situation-specific exercise and does not lend itself to broad generalizations.

Given the long term nature of these investments, twenty year forecasts are necessary for each cost element described above. These forecasts are then discounted and expressed as a levelized rate per kWh of thermal energy. In this context, natural gas prices today, while important, must be viewed in the context of what natural gas prices, and the other cost elements could be in the future as well.

As an example, a 4,250 square foot institutional building would have an expected levelized rate of $0.146/kWh using current natural gas prices, a standard efficiency natural gas boiler and an independent third party forecast of natural gas from GLJ Petroleum Consultants. For clarity, any evaluations of alternatives would have to be done for the particular project and customers and this may or may not represent the thermal rates that they would face.

A recent comparison of the levelized rates for alternative energy sources was provided in response to BCUC IR 2.25.3 of the PCI Marine Gateway proceeding, showing expected values of thermal energy ranging from $0.116/kWh to $0.156/kWh for the various projects. Thus thermal energy solutions using alternative technologies can still be competitive with conventional gas solutions.

In addition, as discussed in the response to BCUC IR 1.97.1, consumers are making energy choices based on considerations other than purely cost, which means that even in situations where there is not a clear cost advantage, the alternative sources are still selected and therefore a competitive alternative. .

Please also refer to the response to BC Util Cust-FBCU IR 1.4.2 for operating cost comparisons.

In FEI's 2012-2013 Revenue Requirement Application, it states that "[i]n the long-run, the more successful the Thermal Energy Services business becomes, the greater the potential benefit to natural gas customers in terms of a recovery of overheads." (Exhibit B-1, p.12, FEI 2012-2013 RRA)

Similarly in that Application, FEI also states that "The growing prevalence of thermal solutions such as solar, DES and geo exchange, regardless of the provider of those services, will have an increasingly significant impact on the natural gas requirements over time. Thus, from the perspective of natural gas customers it is important to understand the growth of these energy alternatives over time and how they may impact the natural gas throughput and utilization." (Exhibit B-1, p.16, FEI 2012-2013 RRA)

8.2 Please discuss how FEI's expanded service offerings into Biomethane, CNG and LNG Fueling Stations, and Alternative Energy Services are affecting its current and future business risk? Please provide any evidence which supports your findings.

Response:

FEI has begun the expanded service offerings in the areas of NGT and biomethane to assist in mitigating its increasing long term business risk due to declining throughput in its core natural gas markets. As stated in the response to BCUC IR 1.6.1, FEI continues to be a natural gas distribution utility whose core business is in the space and water heating markets. The NGT and biomethane initiatives are in very early stages of market development, but are service offerings that are part of, or supplement the core distribution business, with the focus on utilizing FEI's natural gas distribution and transmission system, which provides benefits to existing customers. However, as also discussed in the response to BCUC IR 1.100.2, these initiatives are at the very early stages of development, and currently have no impact on the business risk of the core market, which has increased mainly due to declining annual use rates from existing customers and the declining rate of capture of the new construction market, particularly in the multi-family sector. Since FEI's core business will continue to be in natural gas distribution for space and water heating for the foreseeable future, and it is within this market that FEI faces continuing challenges, attracting and retaining customers in the traditional space and water heating market is important for offsetting the declining throughput from the existing customer base. The degree of success in mitigating throughput declines or the effects of the initiatives on business risk will not be known until the initiatives have reached a more mature stage of development.

In addition, TES is currently being offered by an affiliate, and will either continue to be offered by an affiliate or will be offered by a separate class of service within FEI depending on the outcome of the AES Inquiry. As such, TES has no material impact on risk faced by FEI's core natural gas business (i.e. the proposed benchmark).

9.0 Reference: FEI as Benchmark Utility

Exhibit B1-9, p. 23; Exhibit A2-11, TGI 2009 ROE Application p. 14

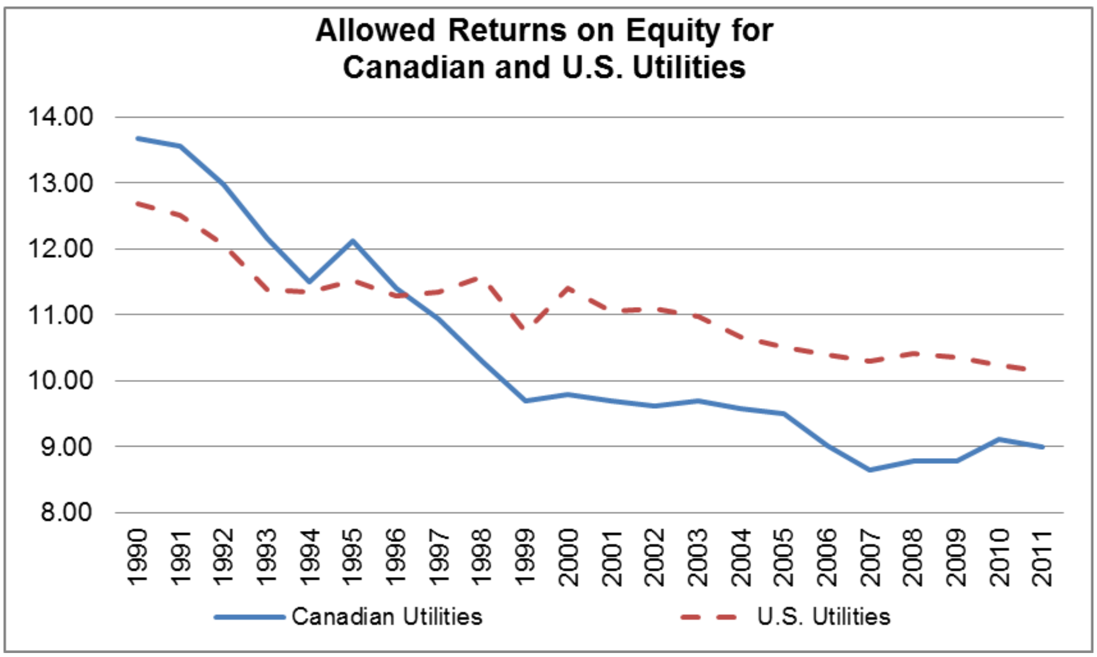
Use of US Utilities as Comparator

Page 23 of the FBCU's evidence says: "The use of US utilities as a comparator group for the determination of ROE and equity thickness is appropriate in this Proceeding, just as it has been appropriate in other proceedings and other jurisdictions."

9.1 Please update the chart on page 14 of the 2009 FEU ROE application to include 2011 data. Please include a description of the samples of both the Canadian utilities and the US utilities.

Response:

Please see the updated chart below. The sample of Canadian utilities is the same as that which appears on Ms. McShane's Schedule 3, Page 2 of 2. The U.S. utilities include all electric and gas utilities cases reported by Regulatory Research Associates.



10.0 Reference: Capital Structure for FEI

Exhibit B1-9, pp. 7, 25; Exhibit A2-13 Bloomberg News

Equity Ratio and ROE Support Credit Ratings and Maintain Financial Flexibility

Page 25 of the FBCU's Evidence states:

"The Commission, in the 2009 Decision, also endorsed the maintenance of a minimum A rating. FEI has ongoing capital requirements to ensure system deliverability, reliability and safety, and support customer growth. FEI needs to access capital markets on a regular basis, in both strong and weak economic conditions and when financial markets are both stable and volatile.", and

"Further weakening in FEI's credit metrics or a change in Moody's views of the regulatory environment and business risk may lead to a downgrade."

Page 7 of the FBCU Evidence describes the capital markets remaining in a period of turmoil since the 2009 Decision. The recent downward trend of long-term Canada bond yields is primarily a function of an increase in investor risk aversion, monetary policy, weak economic conditions, and a smaller supply of safe haven assets, etc.

The Bloomberg News reported on August 6, 2011 that Standard & Poor's downgraded the US's AAA credit rating for the first time to AA+ while keeping the outlook at "negative" (Appendix A2-13). The news article describes that even with the specter of a downgrade, demand for Treasuries surged as investors saw few alternatives amid concern global growth is slowing and Europe's sovereign debt crisis is spreading.

10.1 Notwithstanding the globalized financial market, as long as Canada is a safe haven, is it not true that for many investors, there are few alternatives outside North America, no matter what FEI's credit rating is?

Response:

The FBCU presume that the question refers to alternatives to investors who are seeking debt investments, as the question references FEI's credit rating. The FBCU would not agree that there are few alternatives to investors outside of North America, no matter what FEI's credit rating is. The FBCU acknowledge that FEI is a benefactor of Canada's safe-haven status, which permits FEI to issue debt at lower absolute interest rate levels in current markets than it would otherwise be able to do. The FBCU also acknowledge that FEI's A debt rating provides the company greater access to and a lower cost of debt capital than it would have, were it to have lower investment grade (i.e., in the BBB/Baa category) or non-investment grade debt ratings. However, it does not follow logically that there would be few alternatives outside North America to FEI with a lower credit rating (i.e., a riskier FEI). The lower FEI's credit rating is, the larger would be the pool of alternative investments outside North America. Further, even if FEI were able to access capital in current markets on reasonable terms and conditions at a lower credit rating than it now has, it would not be prudent, in the FBCU's view, to presume that would be the case indefinitely. Further, if FEI were to lose its A credit rating, it should not be presumed that it would be easily restored when it would be most beneficial to FEI.

10.2 Based on FBCU's knowledge, how many major gas and electric utilities in Canada have had their 'A' ratings downgraded since 2009? Please list those utilities.

Response:

Only one gas and electric utility in Canada has had its 'A' rating downgraded since 2009, Hamilton Utilities Corp. S&P downgraded the rating from A+ to A in April 2010.

10.2.1 Please describe the average increase in yields (e.g., in the following quarter) for the utility borrowers that have lost their 'A' ratings since 2009.

Response:

Not applicable as Hamilton Utilities retained a rating in the 'A' category.

11.0 Reference: FEI Business Risks and Credit Metrics

Exhibit B1-9, pp. 22, 26; Exhibit B1-9-1, Appendix A2 DBRS Report

Business Risks, Earnings and Outlook

The FBCU state that since the 2005 ROE Application proceeding, business risks have been increasing. While no new types of business risks have been identified, the key risks are still prevalent and have not declined. In certain instances, the FBCU suggest the trends of business risk are increasing over time. FBCU further submit that a reduction in the equity ratio and ROE could negatively impact credit ratios that are currently viewed at the low end of the acceptable range for an A rating, and potentially lead to rating agencies reconsidering the current ratings.

The Earnings and Outlook Table on page 5 of the DBRS Report dated February 29, 2012 indicates that FEI's rate base has increased by 5 percent since 2006, its reported net income has increased by 50 percent, and its annual return on average common equity exceeded the allowed ROE in each of the last four years 2008 to 2011.

11.1 Is it true that the perceived business risks have not made any negative impact on FEI's earnings since 2005?

Response:

For a history of FEI's utility earnings (net income) from 2002 to 2011 and explanations of significant variances between the allowed and achieved utility regulated net income, please refer to BCUC IRs 1.95.1 and 1.95.1.1.

Contributing to the increase in FEI's annual earnings since 2005 were the increases in the allowed ROE and the equity thickness in its capital structure and the existence of a PBR earnings sharing mechanism from 2004 to 2009. The increases in both the allowed ROE and capital structure in 2009 recognized the increased business risks facing the Company. Further, the PBR earnings sharing mechanism provided the Company and its management team an incentive to initiate additional actions to achieve cost reductions and increase demand for its services, with the financial benefits shared with customers. In all years, as part of the forward looking rate setting regulation used in BC, FEI may earn more or less than the allowed earnings/ROE based on variations from forecasts.

While the above information provides context to explain the increase in FEI's earnings over time, it does not address whether annual earnings achieved would have been higher, in the absence of the business risks and factors the Company faced in each of the years. It is difficult to determine if the achieved annual earnings since 2005 were or were not negatively impacted as a result of the influence of the business risks. As indicated in the evidence of Kathleen McShane Appendix F of Exhibit B-1-9-6 page 41 starting at line 1037, the quantification of the impact of business risks is a qualitative exercise.

"The assessment of business risk is an inherently qualitative exercise, and not amendable to quantification. There is no recognized methodology for isolating individual business risk factors and quantifying the corresponding required increment of common equity or ROE."

As such, it is difficult to ascertain that the increased business risks the Company has faced have not had a negative impact on FEI's earnings since 2005 without knowledge of what earnings would have been in the absence of these business risks.

11.2 Do the FBCU agree with DBRS's rating report assessment that FEI has solid debt-to-capital and interest coverage metrics? Does high dividend payout affect the cash flow-to-debt metric?

Response:

FBCU believes the use of the term "solid" is an overstatement. FEI's debt-to-capital metrics were in-line with its deemed equity thickness requirements. Also, its EBIT gross interest coverage metrics over the period as outlined in the "Financial Information" section on page 1 were close to 2.0x EBIT. FEI doesn't consider a 2.0x EBIT ratio as being "solid". For example, under the Ratings Methodology for Regulated Electric and Gas Utilities published by Moody's in 2009 and still in use today, the CFO-pre Working Capital + Interest metric considers an issuer with a 1.5-2.7x ratio as receiving a Ba rating.

FEI pays dividends consistent with the deemed capital structure and BCUC established ring-fencing guidelines and therefore FEI believes its payout ratio is appropriate. The cash flow to debt metric provided by DBRS is based on Cash Flow from Operations and is before financing activities, such as the payment of Dividends.

12.0 Reference: Debt Related Matters

Exhibit B1-9, p. 31 and Appendix H, p.1

Business Risk

In Appendix H relating to business risk, the FBCU says that Ms. McShane "…articulates how business risk for FEI is the Company's ability to recover (i) the capital investments it has made to serve customers over the long-term, and (ii) an appropriate return on those investments."

The FBCU say on page 31 that "The appropriate portion of short-term and long-term debt will depend on the underlying nature of the assets and timing."

12.1 To what extent can the FEI reduce its business risk related to the risk attributed to falling throughput through actions such as, for instance, matching the term of the debt to the expected economic life of new assets, as opposed to physical life, and making operational changes such as tightening system extension tests to ensure that only extensions that promise long-term throughput growth will be undertaken?

Response:

The Company believes that it has the appropriate policies and procedures in place to effectively manage the risk associated with adding new main extension (MX) customers. As discussed in detail in the response to BCUC IR 1.108.1, the current main extension test (MX Test) serves to mitigate the risk of adding low use residential customers. The MX Test sends economic signals to residential customers including those choosing to add a small number of low demand natural gas appliances. In the case of a low volume customer, it is likely that this customer will have to provide a contribution in aid of construction (CIAC) versus customers choosing to add a larger number of relatively high demand natural gas appliances.

However, the average use of new residential customers has declined when compared to the totals for the existing FEI and FEVI customers. As a result of this decline, the Company believes that the current MX Test, as designed for larger use customers, may be inappropriate for new low use residential customers. The Companies intend to monitor and, if appropriate, conduct a review of the MX Test, the related consumption inputs and the profitability index thresholds.

FEI considers all of its assets will be used to the end of their physical life. FEI's doesn't understand what is meant by expected economic life as opposed to physical life. FEI currently manages its debt by choosing what it thinks are the best pricing options given the terms of the debt available in the market and the life of the assets being added to its rate base portfolio.

13.0 Reference: Preference Share Offering by Parent Company

Exhibit B1-9-5, Appendix A: Section 6, Short Form Prospectus, January 18, 2010, Fortis Inc., $250 million, 10,000,000 Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares, Series H; $25.00 per share to yield initially 4.25% per annum, p. 24

Implied Double Leverage

Page 24 in the section titled "Use of Proceeds" states:

> "The net proceeds of the Offering will be approximately $241.85 million, determined after deducting the Underwriters' Fee (as defined below) and the expenses of the Offering, which are estimated to be $650,000. The net proceeds of the Offering will be used to repay $129 million outstanding under the Corporation's $600 million committed credit facility, which indebtedness was incurred: (i) <u>for funding equity injections into FortisAlberta and FortisBC</u> in support of their capital expenditure programs; (ii) to fund a portion of the acquisition purchase price of Great Lakes Power Distribution Inc.; and (iii) for general corporate purposes. A portion of the proceeds will also be used towards funding an approximate <u>$125 million equity injection into TGI</u> to repay indebtedness under the utility's credit facilities incurred to support working capital and capital expenditure requirements." [Emphasis added]

13.1 Please confirm that a portion of the proceeds from the $250 million preference share issue at an initial 4.25 percent yield was for equity injections into FortisBC Inc. and/or Terasen Gas Inc.

<u>Response:</u>

The preamble to BCUC IR 1.13.1 implies the use of double leverage by Fortis Inc. to fund the equity of its regulated subsidiaries. Fortis Inc.'s approach to funding the regulated businesses is to match the equity component of rate base predominantly with common equity issued by Fortis Inc. The disclosure of the Series H First Preference Shares did indicate that a portion of the proceeds would be used to fund equity injections into Fortis subsidiaries. The proximity of the capital issue and the equity injection make this a logical use of proceeds of which Fortis was required to disclose. However, it is not a simple conclusion that Fortis used preference shares to permanently fund the capital for the additional equity. Fortis' investment in the equity of its regulated subsidiaries comes primarily from its issuance of common equity. The common share dividend reinvestment plans during 2010 provided $80 million in new capital and annually the plans continue to provide a similar level of new common equity. Furthermore, Fortis has publicly issued $300 million of common stock during December 2008 and another $300 million during June 2011. Fortis' long-term capital is used to finance its equity investment in the regulated utilities, goodwill and non-regulated investments and includes firstly common equity, followed by preferred equity and debt. The issuance of these securities is not tied directly to individual use of proceeds rather they are used to manage the non-consolidated capital structure of the corporation to maintain its "A" credit ratings. While the use of proceeds above denote that it may have been used at a point in time to fund equity of the subsidiary utilities, according to Fortis, as at December 31, 2011 Fortis' net investment in non-regulated investments and goodwill totaled ~$2.5 billion (Properties $470M, Generation, $420M & Goodwill $1.6 billion) and Fortis debt and preferred shares totaled ~$2.0 billion ($912M preferred equity & $1.1B debt). The common equity at December 31, 2011 of $3.9 billion supports close to 100% of the rate base equity (excluding goodwill) of Fortis' investment in regulated utilities such as FortisBC Energy.

13.1.1 If confirmed, what were the actual (estimated, if actual is not available) equity injections for each utility on the use of the proceeds from this preference share offering.

Response:

In 2010, as per the financial statements, the equity injections for each company were as follows:

FEI	$125,000,000
FortisBC Inc.	$10,000,000
FortisAlberta	$55,000,000

Please refer to the response to BCUC IR 1.13.1.

14.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, BMO Capital Markets, p. 5; Exhibit B2-7 PMA Direct Testimony 8-2-12, p. 18

Preferred Shares

On page 5, Mr. Engen states he played an advisory role in the recent ATCO Group $925 million preferred shares transaction.

Pacific Northern Gas Ltd. in its 2009 Capital Structure and Equity Risk Premium Application includes Schedule 2 Capital Structure Ratios of Canadian Utilities With Rated Debt with a column for Preferred Stock:

http://www.bcuc.com/Documents/Proceedings/2009/DOC_24093_B-1_PNGW-PNGNE-Application.pdf

14.1 Please provide the specific details of the $925 million preferred ATCO Group offering including issuer company name, date, underwriters, type of deal, terms, and yield.

Response:

The $925 million in preferred share issuances referred to by Mr. Engen included multiple preferred share offerings by Canadian Utilities Limited. The following lists all issuances of preferred shares by the ATCO Group of which BMO Capital Markets has a record.

Issuer	Offering Size	Date	Underwriters	Deal Type	Preferred Share Terms	Yield
ATCO Ltd.	$150	2001/06/21	RBC, BMO (40%) / TD (20%)	Bought	Cumulative Redeemable	5.75%
CU Inc.	$75	2010/11/16	BMO, RBC (40%) / TD (20%)	Bought	5-Year Rate Reset Cumulative Redeemable	3.8%
CU Inc.	$160	2009/03/10	BMO, RBC (40% / TD (20%)	Bought	5-Year Rate Reset Cumulative Redeemable	6.7%

Issuer	Offering Size	Date	Underwriters	Deal Type	Preferred Share Terms	Yield
CU Inc.	$115	2007/04/03	BMO, RBC (40%) / TD (20%)	Bought	Cumulative Redeemable	4.6%
Canadian Utilities Limited	$150	2012/06/18	RBC, BMO (30%) / TD (22%) / Scotia (18%)	Bought	Cumulative Redeemable	4.9%
Canadian Utilities Limited	$150	2012/05/30	BMO, RBC (30%) / TD (22%) / Scotia (18%)	Bought	Cumulative Redeemable	4.9%
Canadian Utilities Limited	$325	2011/09/13	RBC, BMO (30%) / TD (22%) / Scotia (18%)	Bought	5-Year Rate Reset Cumulative Redeemable	4.0%
Canadian Utilities Limited	$150	2003/04/02	RBC, BMO (40%) / TD (20%)	Bought	Perpetual Preferred Shares	6.0%
Canadian Utilities Limited	$150	2002/11/19	BMO, RBC (40%) / TD (20%)	Bought	Cumulative Redeemable	5.8%
Canadian Utilities Limited	$50	1994/11/23	BMO, Rich Green, RBC (33.33%)	Bought	Cumulative Redeemable	6.6%
Canadian Utilities Limited	$150	1994/03/14	RBC, BMO, Rich Green (33.33%)	Bought	Cumulative Redeemable	5.3%
Canadian Utilities Limited	$125	1993/09/08	Rich Green, RBC, BMO (33.33%)	Bought	Cumulative	5.9%
Canadian Utilities Limited	$125	1991/06/25	Rich Green, BMO, RBC (33.33%)	Bought	Cumulative Redeemable	8.0%

Issuer	Offering Size	Date	Underwriters	Deal Type	Preferred Share Terms	Yield
Canadian Utilities Limited	$75	1991/04/18	RBC, BMO, Rich Green, TD (25%)	Private	Perpetual Cumulative	7.875%

14.2 Please elaborate on the types of preferred shares being issued in Canada within the last 5 years.

Response:

Mr. Engen advises that of the $35.6 billion of preferred shares issued in Canada over the past five years, the vast majority ($29.5 billion) have in the form of "rate reset" preferred shares.

Rate reset preferred shares are structured with largely the same redemption, voting, rights on liquidation, restrictions on payments and reductions of capital, and purchase for cancellation terms and conditions as fixed rate preferred shares.

Unlike fixed rate preferred shares (term or perpetual), rate reset preferred shares have an initial term of, typically, five years and a fixed yield during the initial term. At the end of the initial term investors have a choice to make. They can continue to hold their preferred shares or convert them into five-year floating-rate preferred shares. This process repeats itself every five years.

If investors hold on to their preferred shares, they will receive a fixed yield for another five-year term based on the sum of the 5-year Government of Canada bond yield at that time and a spread, the same spread over the benchmark bonds used when the rate reset preferred shares were first issued.

For those investors who choose to convert to floating-rate preferred shares, the new yield will be the sum of the three-month Government of Canada treasury bills at that time plus a spread, again, the same spread over the benchmark bonds used when the rate reset preferred shares were first issued.

Occasionally during the last five years the market opened up sufficiently that companies were able to issue fixed rate perpetual preferred shares. Such issuances represent a very small portion of the preferred share market, amounting to $5.0 billion in aggregate issuances over the period.

14.2.1 Who are the typical buyers (retail, institutional, or other) of preferred shares? Please elaborate with further details.

Response:

Mr. Engen advises that in Canada preferred shares investors are comprised of both retail and institutional investors. Over the past five years, however, retail has averaged over 85% of aggregate preferred share demand. Specific proportional participation in preferred share offerings is not public information.

14.2.2 Please explain the advantages and disadvantages of an issuer making a decision to issue preferred shares instead of common stock or bonds.

Response:

Mr. Engen is of the view that typically the primary reasons for issuing preferred shares include:

- Issuing preferred shares avoids EPS dilution associated with issuing additional common equity
- Preferred shares can be used to strengthen a company's balance sheet by replacing debt issuances
- In the face of large capital expenditure programs expected to produce substantial future cash flows, issuing preferred shares can be an attractive alternative to issuing common equity. By their terms, preferred shares can generally be redeemed at a later date at their issue price when future cash flows from current capital expenditures are being generated. In such a case, preferred shares would be considered "rented equity". Of course, the issuer could always issue common equity and take it out at a later date using, for example, a normal course issuer bid, but faces the risk that the share price has risen, potentially requiring substantially more capital to repurchase the common equity.

On the positive side, unlike debt obligations, an issuer is not contractually obligated to make dividend payments on its outstanding preferred shares. And unlike debt obligations, missing a dividend payment does not give preferred shareholders the ability to take control of the company or force it into bankruptcy. That said, this advantage is often of little value in that the company will generally do all it can to meet its preferred share dividend payments because of the very negative financial market reaction one would expect to a missed dividend payment. Missing the payment would indicate the company is having serious financial difficulties, scaring away investors and making capital raises more difficult and expensive. In addition, preferred share terms and conditions generally prohibit distributions to common shareholders until preferred share dividends have been made.

Preferred shares generally do not receive full equity treatment from rating agencies or investors. Depending on a preferred share's structure, equity treatment will commonly range between 0% to 50%.[2] Meaning, in the latter case, for example, that for every $1.00 of preferred shares outstanding, the issuer would receive $0.50 of balance sheet equity "credit". Credit rating agencies typically have limits on the amount of preferred shares a company can issue beyond which no equity credit is extended to further preferred share issuances.

Preferred share market access is subject to narrow or even close from time to time in reaction to too many new issuances coming to market within a period of time. Only after the market has absorbed the multiple issues will it re-open to further offerings. The preferred share market has less capacity to absorb preferred share issuances than does either of the common equity or bond markets for their respective securities. The market can also become constrained and challenged in reaction to unsuccessful or badly priced preferred share offerings.

14.2.3 Please elaborate on why an issuer chooses to make a preferred share offering.

Response:

Please refer to the response to BCUC IR 1.14.2.2.

14.3 Is Mr. Engen aware of any regulated utility company (not a holding company) directly issuing preferred shares to the general public within the last 10 years? If so, please provide a listing with details of each issuance.

[2] In rarer circumstances and depending on structuring, preferred shares can achieve 70% or higher rating agency equity treatment.

Response:

Mr. Engen is not aware of any regulated utility company (at an operating company level) which has directly undertaking a public offering of preferred shares.

14.3.1 For CU Inc. please explain its history of issuing preferred shares. Also please provide details of CU Inc.'s recent preferred share offering, Cumulative Redeemable Preferred Shares Series 4.

Response:

Please refer to the response to BCUC IR 1.14.1 which provides a full listing of CU Inc.'s preferred share issuances. The following table, an excerpt from the full table, summarizes the CU Inc. new issue of Cumulative Redeemable Preferred Shares, Series 4.

Issuer	Offering Size	Date	Underwriters	Deal Type	Preferred Share Terms	Yield
CU Inc.	$75	2010/11/16	BMO, RBC (40%) / TD (20%)	Bought	5-Year Rate Reset Cumulative Redeemable	3.8%

The 3.8% yield continues through the initial period ending June 1, 2016 and resets every five years thereafter at a rate equal to the 5-year Government of Canada bond rate plus 136 bps. At each of these five-year intervals purchasers may convert their preferred shares into an equal number of Floating Rate Cumulative Preferred Shares Series 5 (floating at 90-day T-Bills plus 136 bps).

Full details of the offering are outlined in CU Inc.'s short form prospectus provided in Attachment 14.3.1.

14.3.2 In Mr. Engen's opinion, why would CU Inc. issue preferred shares instead of debt?

Response:

The company required the incremental equity treatment associated with the preferred share issuance on its balance sheet to maintain its credit quality and ratings. Its credit quality and ratings would have deteriorated had the company financed all of its capex program with debt.

14.4 What would be the investor's receptiveness to a regulated utility company issuing preferred shares directly to the public? Please elaborate.

Response:

The market would generally be expected to be supportive of a utility company (operating company level) offering of preferred shares. The Canadian market has many financial institution preferred share issuers and fewer non-financial issuers. New product from the energy infrastructure sector would help diversify investor preferred share portfolios. Market receptiveness would depend, of course, on preferred share credit ratings (expected to be in Pfd-2/P-2 – ratings category for best market access), pricing, offering sizes, and then current market conditions.

14.5 Pacific Northern Gas Ltd.'s Schedule 2 shows utilities with preferred stock. In the opinion of Mr. Engen, please comment on preferred equity in a utility's capital structure including its purpose, appropriateness, regulatory treatment, accounting treatment, credit rating agency treatment, and nature of funding source relative to debt and common equity.

Response:

Consideration	Commentary
Purpose	Refer to the response to BCUC IR 1.14.2.2
Appropriateness	The decision to include preferred shares in a company's capital structure depends on the company's need for capital, need for duration, the relative costs of equity, debt, and preferred shares, need to avoid EPS dilution, and target credit metrics and ratings. Under the right circumstances, including preferred shares in the company's capital structure could be appropriate.

Consideration	Commentary
Regulatory Treatment	Mr. Engen has not researched the regulatory treatment of preferred shares.
Accounting Treatment	Preferred shares are recorded on the company's balance sheet as either part of the company's share capital or as part of long term debt (or potentially as both as a hybrid financial instrument).The preferred shares would be carried at an amount equal gross proceeds less net issuance costs. The classification of preferred shares is dependent on the terms and conditions of the preferred shares.
Credit Rating Agency Treatment	Subject to rating agency issuance limits (maximum proportion preferred shares can be carried on the balance sheet before no further equity treatment will be afforded to further preferred share issuances) and preferred share structuring, rating agencies may give up to 50% equity credit/treatment for preferred shares.
Nature of Funding Source Relative to Debt	Preferred shares, as hybrid capital, are a more expensive source of capital than debt of an equivalent term.
Nature of Fund Source Relative to Common Equity	Preferred shares, as hybrid capital, would generally be expected to be a less expensive source of capital than common equity although more preferred share capital is required to achieve the same balance sheet support as common equity.

In Ms. Ahern's Evidence provided in Exhibit B2-7 (PMA Direct Testimony 8-2-12, p. 18), she indicates that "[f]inancial risk is the additional risk created by the introduction of senior capital, i.e., debt and / or preferred stock, into the capital structure. The interest and / or preferred dividend payments associated with debt and / or preferred stock must be paid by the company before common share dividends as common shareholders are last in line in any claim on a company's assets and earnings."

14.6 Please comment on whether the FBCU agree with this view and discuss how the existence of an amount of preferred stock affects a utility's risk profile.

Response:

Yes, the FBCU agree with this definition, as financial risk, from the equity investor's perspective, relates to the extent to which there are fixed obligations which must be serviced before there is any return to the equity shareholder. These obligations include interest and preferred dividends. Preferred shares are not tax-deductible, and as such, are an expensive and inefficient form of debt. With respect to the existence of preferred shares in the capital structure, the impact on a utility's overall risk profile depends on the overall mix of debt, preferred shares and common equity and the characteristics of any preferred shares. Preferred shares are given varying degrees of equity credit by the debt rating agencies, depending on features such as whether the dividends are cumulative, whether they have retraction or redemption options, whether they are convertible into common shares, etc. A preferred share component in the capital structure, in place of debt, may enhance certain credit ratios and potentially reduce the cost of debt, as preferred equity is subordinate to debt. However, since the cost of preferred shares is higher than the cost of debt, as they are both subordinate to debt and not tax deductible, the overall cost of fixed obligations would be likely be higher with preferred shares in the capital structure. Preferred shares would not be an appropriate alternative for common equity, as preferred equity simply creates more financial risk from the perspective of the common equity holder and raises the cost of common equity.

15.0 Reference: Opinion Evidence of Mr. Engen

Exhibit B1-9-6, Appendix E, p. 33

Cost of Debt

Figure 12 on page 33 shows the 30-year yield spreads of six Canadian companies over the past ten years.

15.1 Please confirm that the specified companies used in the chart are predominantly the publicly traded holding companies of the regulated entities.

Response:

Of the six bond issuers referred to in Figure 12 of Mr. Engen's written evidence, two (Enbridge and Emera) are publicly traded "holding companies" of regulated utilities. Although not publicly traded, CU Inc. is a "holding company" of ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd.

15.2 Please provide the credit ratings for the specified sample of companies and the credit ratings for their related regulated operating companies.

Response:

Please see the following table.

Issuer	S&P	Moody's	DBRS
TransCanada PipeLines	A-	Baa1	
Enbridge Inc.	A-	Baa1	AL
• **Enbridge Pipelines**	A-		A
• **Enbridge Gas Distribution**	A-		A
Gaz Metro	A-		A
• **Green Mountain**	BBB	Baa2	
• **Central Vermont**		A3	
Emera	BBB+		BBBH
• **Nova Scotia Power**	BBB+		AL
CU Inc.	A		A
FEI		A3	A

15.3 Are the credit ratings for holding companies lower than their related regulated operating companies?

Response:

As illustrated in the table in response to BCUC IR 1.15.2, of the three measurable instances of holdco/opco credit ratings comparisons[3], ratings between the entities are a mix of "unchanged" and one "notch" downgrades from opco to holdco.

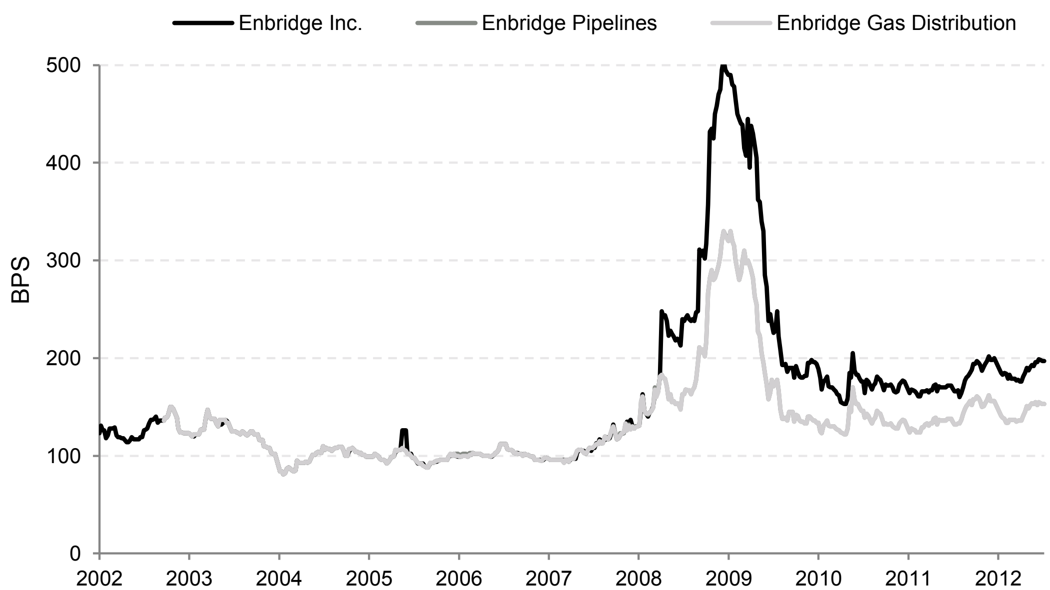
15.4 For the Canadian sample of utilities, please provide a graph of the 30-year credit spread for the holding companies and their related regulated operating companies.

Response:

The requested charts are below.

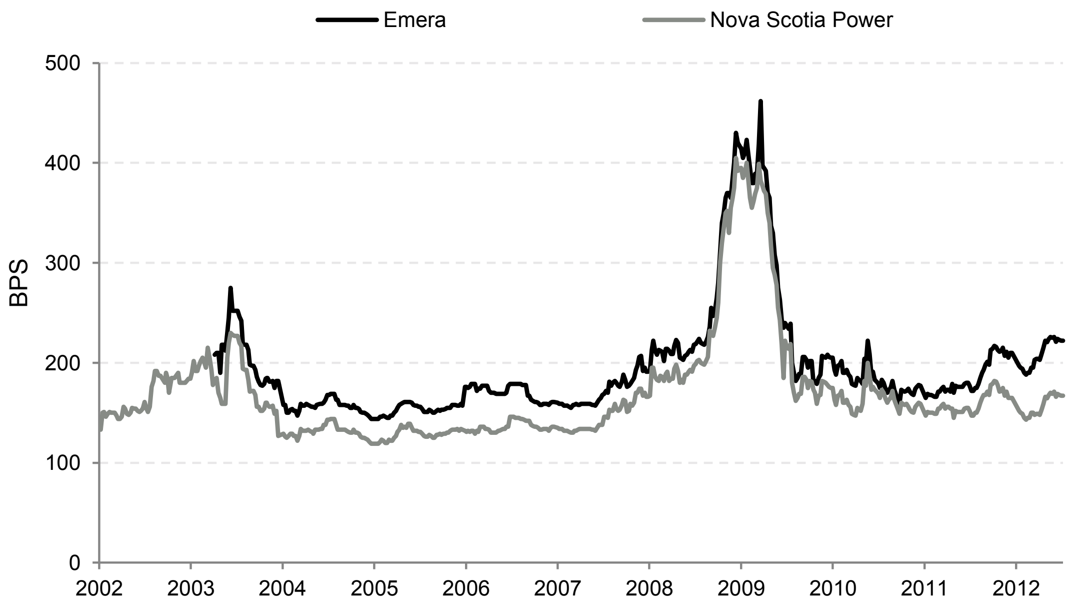
3 (1) Enbridge-Enbridge Pipelines, (2) Enbridge-Enbridge Gas Distribution, (3) Emera-Nova Scotia Power. Excludes Gaz Metro and its subsidiaries.

Enbridge Inc. vs. Enbridge Pipelines/Enbridge Gas Distribution Credit Spreads



In the case of the Enbridge-Enbridge Pipelines/Enbridge Gas Distribution credit spreads, the average spread differential between the "holdco" and the "subcos" was less than 1 bps from September 2002 until the beginning of the financial crisis in July 2007. From July 2007 to July 2009, the average spread differential rose to 70 bps. From July 2009 until July 2012 the average holdco-subco spread differential stood at 40 bps.

Emera vs Nova Scotia Power Credit Spreads



In the case of the Emera-Nova Scotia Power credit spreads, the average spread differential between the "holdco" and the "subco" was 28 bps from September 2002 until the beginning of the financial crisis in July 2007. From July 2007 to July 2009, the average spread differential fell to 23 bps. From July 2009 until July 2012 the average holdco-subco spread differential stood at 27 bps with a significant widening trend in recent months.

15.5 If there is a lower risk premium for the cost of debt for 30 year bonds of the operating companies relative to their related publicly traded holding companies, should there also be a lower risk premium for the cost of equity at the operating company level relative to the holding company?

Response:

Please refer to the response to BCUC IR 1.73.5.

16.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, p. 11; Exhibit B1-9-3, Appendix A Section 3B Company Specific Information for FEI, BMO Research Comments dated April 9, 2012

Relevance of ROE

On page 11, Mr. Engen states that "Nothing can be learned about the appropriateness of allowed return on equity from Canadian merger and acquisition activity involving regulated assets. Regulated asset buyer expected returns on equity are supported by many factors <u>other</u> than allowed ROE."

The BMO Research Comment sheet displays a number of metrics, including the ROE.

16.1 Please confirm or clarify that Mr. Engen's use of the word "other" in the comment above is not intended to exclude "allowed ROE" as one of the factors considered by asset buyers.

<u>Response:</u>

Confirmed. The second line of the paragraph would have been better written to read, "Regulated asset buyer expected returns on equity are supported by many factors other than ***just*** allowed ROEs".

16.2 In Mr. Engen's view, do asset buyers consider return on capital and return on equity in their purchasing decisions?

<u>Response:</u>

They do and as discussed in Mr. Engen's evidence, when acquiring regulated assets, returns on capital and returns on equity are not uniquely defined by allowed ROEs.

16.3 In Mr. Engen's view, do equity analysts consider the return on equity in their analysis and buy/sell recommendations to investor clients?

Response:

In making their buy/sell recommendations equity analysts focus on share returns determined by dividends and capital appreciation (total return). A company's return on equity is interesting from a valuation perspective to the extent it drives either dividends or capital appreciation (share price increases) – the two sole factors which determine shareholder returns on their equity investment (company shares).

16.4 The Research Comment states that the reader can refer to a full report for further details. Please provide the full report to which the research comment refers, as well as any related utility sector reports dated in April 2012.

Response:

The requested information is provided in Attachment 16.4. BMO Capital Markets did not have any other utility sector reports during the requested period.

17.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, pp. 18-23

Market Volatility and Volumes

On pages 18-23, Mr. Engen's Opinion Evidence provides Figure 3 – VIXC Index Performance, Figure 4 – VIX Index Performance, Figure 5 – S&P/TSX Volatility, and Figure 6 – Canadian Equity Market Trading Volumes.

17.1 If available, please provide each figure above to reflect the utility sector and contrast the utility sector with the overall market.

Response:

- VIXC Index Performance for Utilities

  The data required to prepare the requested chart is not available.

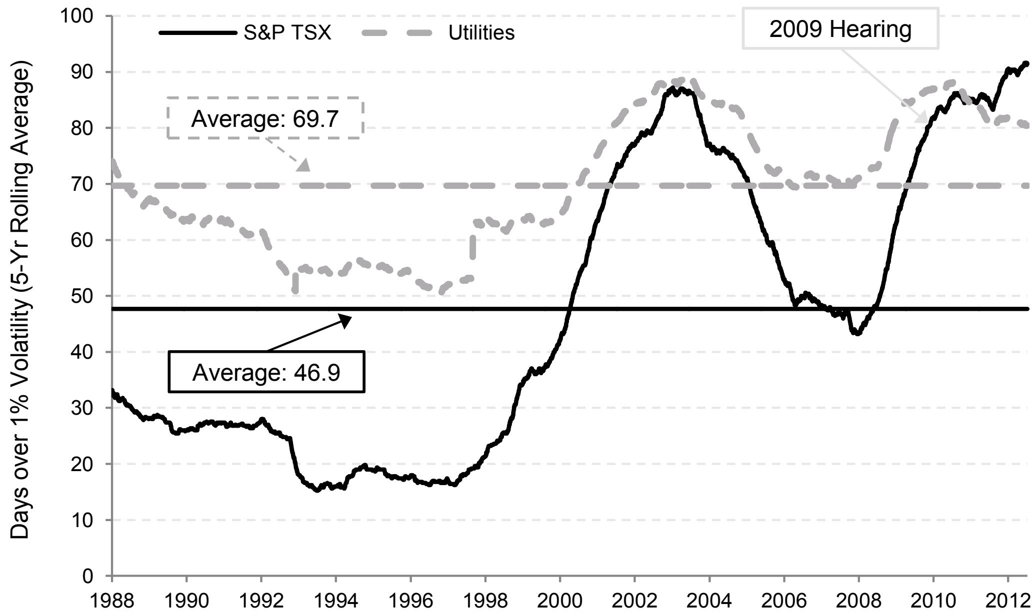
- VIX Index Performance for Utilities

  The data required to prepare the requested chart is not available.

- Canadian Utility Group Volatility (1%+ Trading Days)

  The requested chart is below although data is only available for the period beginning in 1988. Volatility for S&P/TSX Composite Index has been added to the chart for comparative purposes. As illustrated in the chart, until only recently the Canadian Utilities Group has been significantly more volatile than the Index over the period.

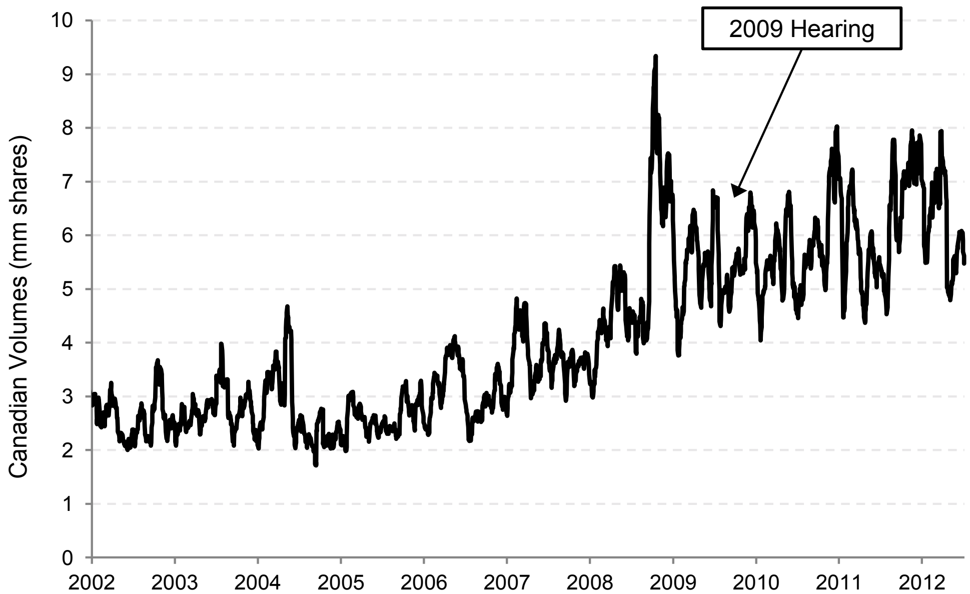
Canadian Utility Group vs. S&P/TSX Composite Index 1%+ Trading Days
January 1998 – July 2012



- Canadian Utility Group Trading Volumes

  The requested chart is below. Trading volumes had been on a general upward trend beginning in 2007. The upward trend flattened out somewhat in recent years. Although volumes dropped in early 2012, it is too early to tell whether the drop is part of a downward trend or is more a reflection of historical trading patterns.

Canadian Utilities Group Trading Volumes
January 2002 to July 2012



17.2 If available, please provide historical realized volatility of the index and the utility sector.

Response:

Historical realized volatility in the Canadian Utility Group is demonstrated in the chart "Canadian Utility Group vs. S&P/TSX Composite Index 1%+ Trading Days" provided in response to BCUC IR 1.17.1.

17.3 Please explain any notable changes over time for the requested information.

Response:

Please refer to the commentary provided in response to BCUC IR 1.17.1.

18.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, pp. 23, 24

Mutual Fund Flows

On page 23 of Mr. Engen's testimony, Mr. Engen states that "Canadian mutual fund funds flows remains in heavily negative territory (and have been for the past four years) while bond and income funds have enjoyed strongly positive fund flows."

18.1 Please provide a definition of "income funds" and elaborate on the characteristics of "income funds".

Response:

Mr. Engen's discussion of fund flows for bond and income mutual funds refers to bond-based mutual funds and fixed income-based mutual funds. It is not a discussion, *per se*, of "income funds".

The bond and income fund category is an aggregation of net funds flows attributable to all bond funds as defined and reported by IFIC. IFIC defines bond funds as either Domestic Fixed Income or Global & High Yield Global & High Yield Fixed Income.

Domestic Fixed Income includes the sub-categories: Canadian Fixed Income, Canadian Inflation Protected Fixed Income, Canadian Long Term Fixed Income, and Canadian Short Term Fixed Income.

Global & High Yield Fixed Income includes the sub-categories: Global Fixed Income and High Yield Fixed Income.

18.2 As of July 31, 2012, what companies are in the top 10 holdings of the "BMO Monthly Income Fund"?

Response:

The BMO Monthly Income Fund invests in a combination of:

- fixed-income securities issued by the federal government, provincial governments, government agencies and corporations; and
- preferred and common shares, REITs, royalty trusts and other high-yielding investments.

The following table describes the top ten holdings in the BMO Monthly Income Fund as of August 31, 2012.

Company	% of Assets
Royal Bank of Canada	2.9%
TD Bank	2.8%
Canadian National Railway	2.4%
Enbridge Inc.	2.4%
Bank of Nova Scotia	2.3%
BMO High Yield US Corp Bond Hed ETF	2.3%
TransCanada Corp.	1.7%
Province of Ontario 9.5% JUL/13/22	1.6%
BCE Inc.	1.5%
CIBC	1.4%

19.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, p. 26

P/E ratios

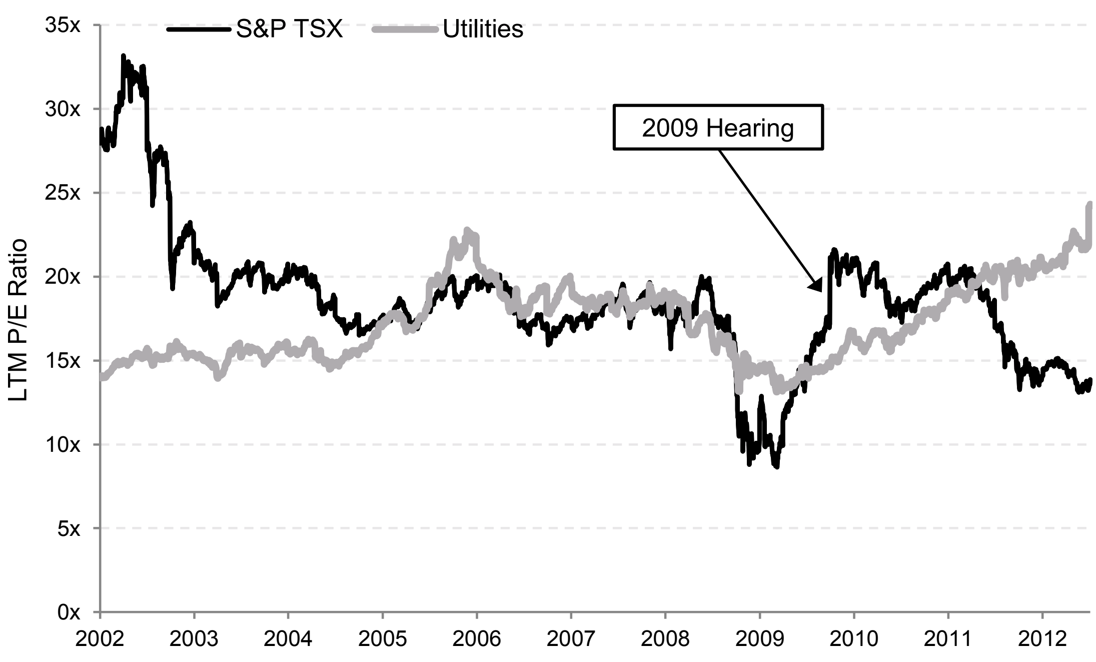
On p. 26 of Mr. Engen's testimony, Mr. Engen states that "The falling trend in the S&P/TSX's P/E ratio over the past two years taken together with growth in corporate earnings during the same period as demonstrated in Figure 9, is compelling evidence that the cost of equity in Canada has been rising." Mr. Engen also provides a chart of the P/E ratio for the S&P/TSX Composite in Figure 8.

19.1 Please provide a chart of the P/E ratio of the utility sector since 2002, in a similar format as Figure 8.

<u>Response:</u>

The requested chart is below. For comparative purposes, the S&P/TSX Composite Index's historical P/E ratios have been added to the chart.

Canadian Utilities Group Historical P/E Ratios
January 2002 – April 2012

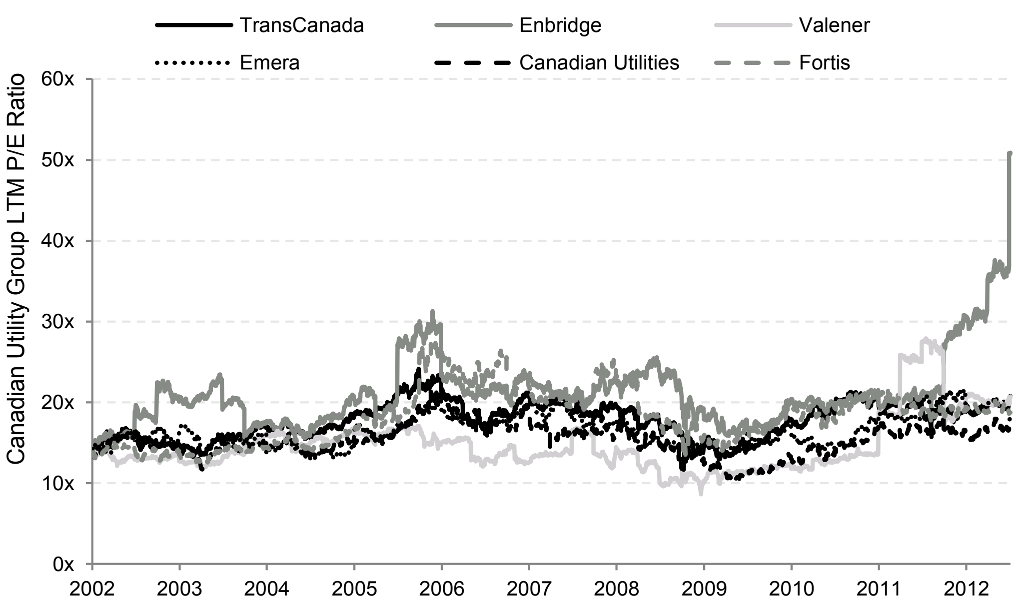


19.2 Please provide charts of the P/E ratios for the following companies: Fortis Inc., Gaz Metro/Valener, TransCanada, Enbridge, Emera, and CU.

Response:

The requested chart is below.

Individual P/E Ratios of Canadian Utilities Group Constituents
January 2002 – April 2012



19.3 Please describe the trend in P/E ratios for the companies mentioned above, and compare to the trend P/E for the TSX Composite.

Response:

From the beginning of 2002 to early 2005 the Canadian Utilities Group P/E ratio remained at relatively stable valuations at in the range of 15x earnings. P/E multiples for the index, on the other hand, were in a steady decline during the same period, falling from over 30x earnings in 2002 to well below 20x by the end of the period. Over the following three years P/E ratios for both the utilities and the index were generally in line with each other with brief periods of higher utilities' ratios as both Enbridge and Fortis multiples temporarily advanced higher.

Beginning in 2008 the P/E ratios for both groups began to decline and as the 2008-2009 market crisis took hold their P/E ratios declined more rapidly, although the index's ratio fell harder and further. Both began to recover in mid-2009 although the index's ratio improved more rapidly and rose to much higher levels of just over 20x earnings by early 2010. It wasn't until May 2010 that the utilities returned to their 10-year average P/E ratio of 17.3x.

For the next year and a half the index continued to trade at roughly 20x earnings while the utilities P/E ratio continued to steadily rise. By mid-2011 their ratios converged in the 20x earnings range at which point the index's P/E ratio went into a steady decline remaining at levels of less than 15x earnings today. During the same period the utilities group's average continued to advance, primarily driven by an early, but temporary jump in Valener valuations (resulting from a sudden drop in the company's earnings in early 2011 from, in part, a decline in allowed ROEs and a milder winter), and a sharp increase in Enbridge P/E multiples to over 50x as the market looks forward to substantial growth in Enbridge's earnings. Absent Enbridge's extraordinary P/E valuation, the group P/E ratio on September 14, 2012 (average August 14 to September 14) would be 19.6x, much closer to the group's 10-year average of 17.3x.

Overall and through the 10-year period and currently, the group has traded within a band of 15x to 20x earnings, with two notable exceptions largely driven by extraordinary Enbridge valuations. Absent Enbridge's very high trading multiples, the group continues to trade in that band today.

19.4 If the falling trend in P/E of the TSX Composite represents compelling evidence that the cost of equity has been rising, as described in Mr. Engen's comments above, would the opposite movement of a rising trend in P/E imply a falling cost of equity?

Response:

It could, depending on the circumstances of the situation. Where earnings are flat to falling, a rising trend in P/E ratios can generally be taken to mean that the earnings are being more highly valued and would be associated with a falling cost of equity.

Where, on the other hand, earnings are rising, a rising trend in P/E ratios may only reflect expected increases in earnings. That is, equity investors begin paying up before the expected earnings arrive because they know the increased earnings are coming. In that case, the rising P/E would not be associated with a falling cost of equity. A rising trend in P/E ratios would only be taken to reflect higher earnings valuations (and a falling cost of equity) where the increase in P/E ratios effectively outstrips the expected growth in earnings.

In the case of the Canadian Utilities Group, with strong recent earnings growth and 2012-2014 consensus EPS growth forecast of over 10%, it is not possible to conclude whether the rising P/E ratio for the sector is a result of a lower cost of equity.

20.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, pp. 32-34

Debt Market Conditions

On page 32 Mr. Engen's testimony, Mr. Engen described the change in generic 'A' spreads between September 2009 and July 2012 as follows: "Spreads at the short end of the curve have improved since then,…(5-year) (10-year)… while at the long end of the curve spreads are the same". On page 34 of Mr. Engen's testimony, Mr. Engen states that "the average Canadian utilities group 30-year spreads were 163 bps on September 25. Their spreads have widened materially and stood at 177 bps as of July 6, 2012."

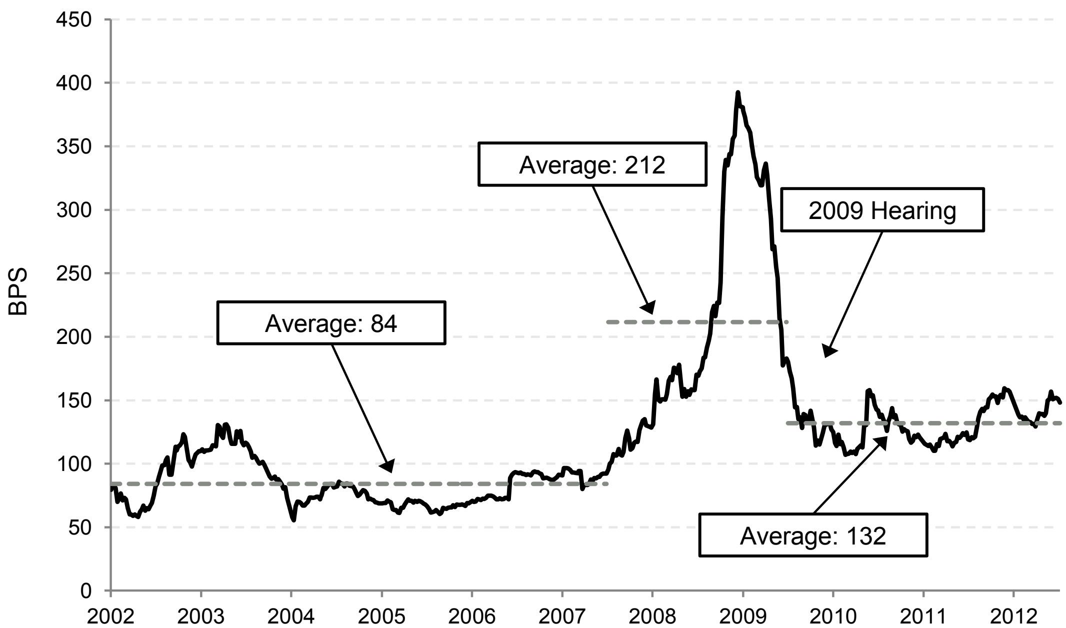
20.1 Please describe the spread movement of the utility group in the 5-year and 10-year area over the same time horizon.

Response:

The following figure illustrates the average of the Canadian energy infrastructure companies' 10-year yield spreads over the past 10 years. Over the period from January 2002 to the extraordinary run up in spreads beginning in July 2007 10-year yield spreads for Canadian utilities had averaged 84 bps. 10-year yield spreads then leapt upward averaging 212 bps from June 30, 2007 to June 30, 2009 and touching almost 400 bps in late 2008.

Since then spreads recovered materially from their highs averaging 132 bps since June 2009 and well above the 84 bps pre-market crash level.

Canadian Utility Group 5-Year Spreads
January 2002 – July 2012

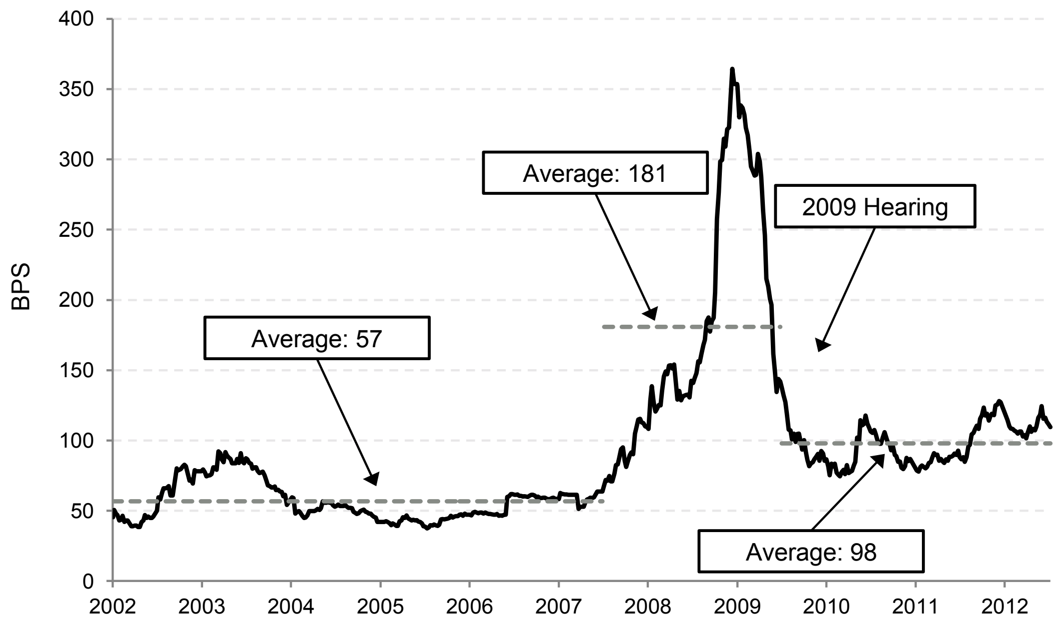


At the time the BCUC heard evidence in the 2009 Proceedings, the average Canadian utilities group 10-year spreads were 94 bps on September 25. Their 10-year spreads have widened materially and stood at 110 bps as of July 6, 2012.

The following figure illustrates the average of the Canadian energy infrastructure companies' 5-year yield spreads over the past 10 years. Over the period from January 2002 to the extraordinary run up in spreads beginning in July 2007 5-year yield spreads for Canadian utilities had averaged 57 bps. 5-year yield spreads then leapt upward averaging 181 bps from June 30, 2007 to June 30, 2009 reaching over 350 bps in late 2008.

Since then spreads recovered materially from their highs averaging 98 bps since June 2009 and well above the 57 bps pre-market crash level.

Canadian Utility Group 10-Year Spreads
January 2002 – July 2012



At the time the BCUC heard evidence in the 2009 Proceedings, the average Canadian utilities group 5-year spreads were 134 bps on September 25. Their 5-year spreads have widened materially and stood at 148 bps as of July 6, 2012.

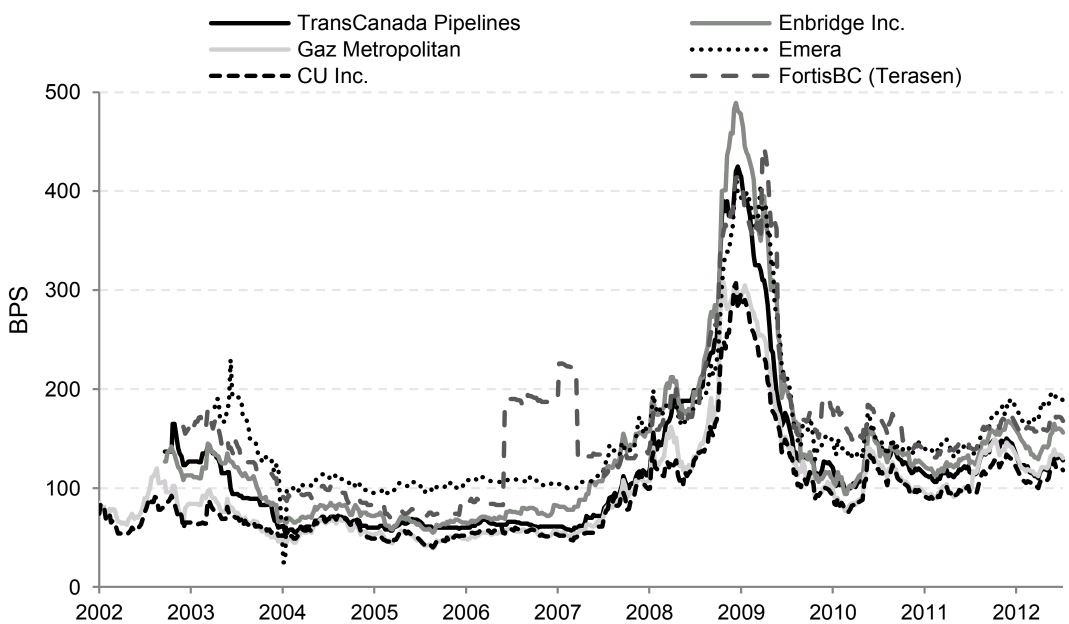
20.2 What are the constituents and weights of the utility group?

Response:

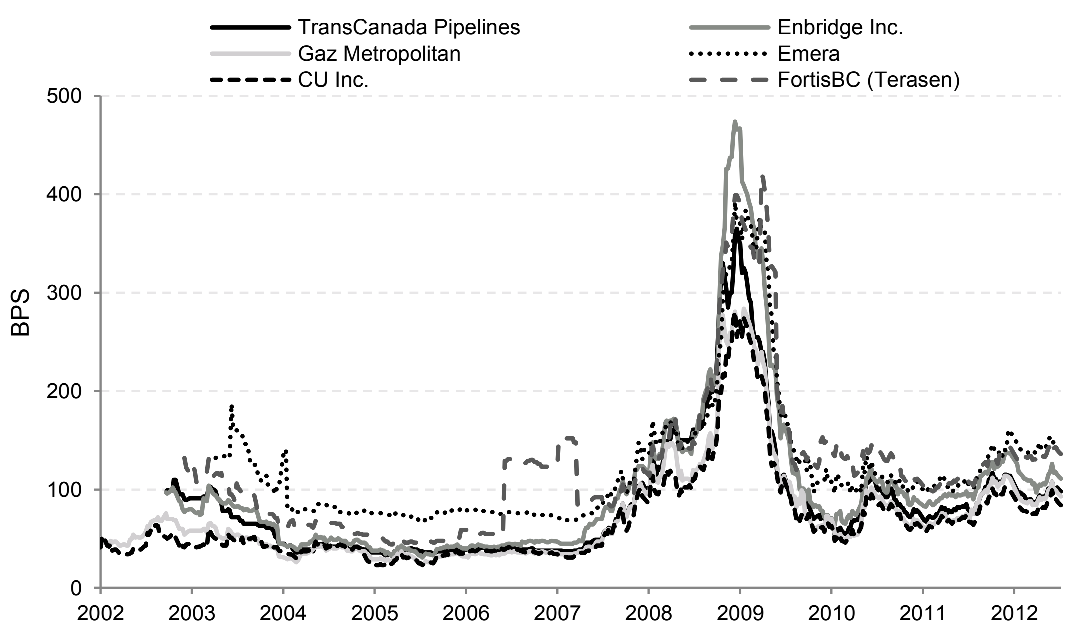
The constituent companies included in the Canadian Utilities Group are described on page 32 of Mr. Engen's evidence and include FEI, Gaz Metro, TransCanada, Enbridge, Emera, and CU. Group spreads are a simple average of the constituent companies.

Individual spreads for each of the constituent companies for the 5 and 10-year bond spreads are illustrated in the charts below.

Canadian Utility Group 5-Year Spreads
January 2002 – July 2012



Canadian Utility Group 10-Year Spreads
January 2002 – July 2012



20.3 Please provide a description and reasons for the unchanged spread of the generic 'A' 30-year area of the curve, in comparison to the utility group 30-year spreads that "widened materially."

Response:

Canadian Utility Group spreads widened as all-in yields approached levels beyond which investors did not want to go. Effectively, investors have a type of "minimum all-in yield". Consequently, as Government of Canada benchmark bond yields fell, all-in yields did not fall on a corresponding 1-for-1 bps decline which caused Canadian Utility Group spreads to widen out. Canadian generic "A", spreads, on the other hand, started out at higher levels so that investors' minimum all-in yield threshold was not tested.

20.4 Please provide a list of significant changes to the constituents and largest contributors to spread movements of both the 30-year generic 'A' and utility sector during this time horizon.

Response:

No changes were made to the composition of the Canadian Utilities Group used by Mr. Engen over the referenced 10-year period. As illustrated in Figure 12 of Mr. Engen's evidence, all of the six referenced issuers generally tracked the group's spread movements resulting in largely similar contributions to spread movements over the past 10 years.

Mr. Engen is unable to identify changes to the constituents in the Canadian generic "A" spreads. The generic A-rated 30-year credit spread is calculated as a simple average of the 30-year credit spreads of all A-rated (A-/A/A+ by S&P) companies BMO Capital Markets' corporate debt trading desk actively tracks on a daily basis. As companies ratings change over time, and companies are either added/removed from the desk's coverage universe, the list of companies used to calculate a generic spread changes over time. At present over 200 companies are tracked by BMO Capital Markets.

21.0 Reference: Opinion Evidence of Aaron Engen

Exhibit B1-9-6, Appendix E, pp. 38-39

Rating Downgrade Impact

On pages 38-39 of Mr. Engen's testimony, Mr. Engen says that "…As such, allowing or requiring a reduction in FEI's credit rating would directly and adversely affect bondholders who invested in FEI bonds with the reasonable expectation that the company's regulatory environment would protect their return on and of capital – not negatively affect the value of their investments."

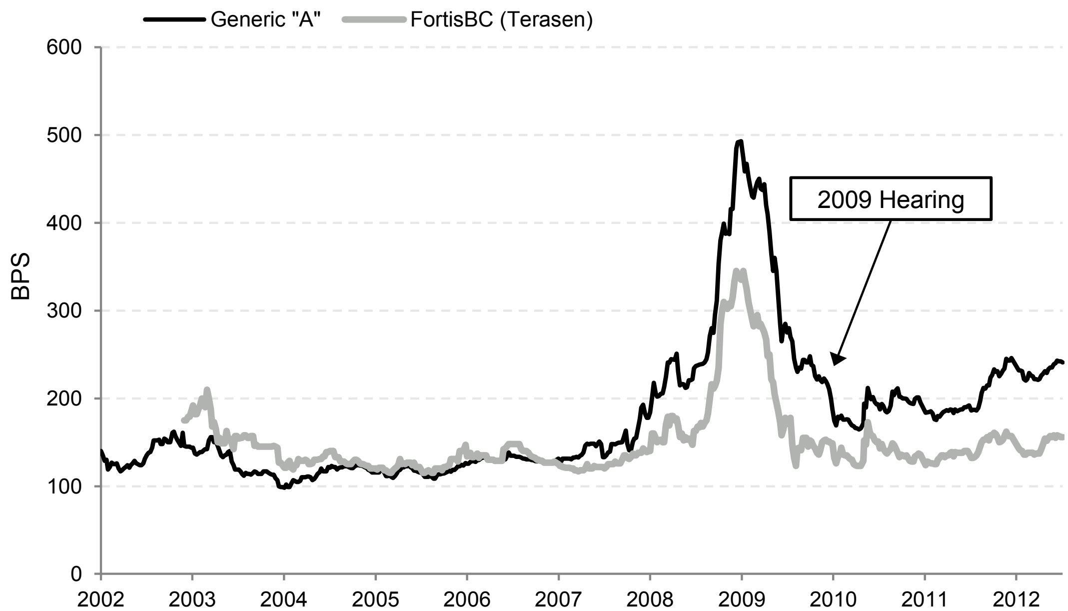
21.1 With reference to the phrase "…bondholders who invested in FEI bonds with the reasonable expectation that the company's regulatory environment would protect their return on and of capital….", to what extent do bondholders hold a reasonable expectation that the regulatory environment affords them some special level of protection?

Response:

The investment community has come to view Canada's regulatory environment as one in which investors' rights to receive a fair return on and of capital are fundamental and will be protected by regulators. Regulated businesses are viewed as being less risky because they are regulated. If regulated entities find themselves in trouble, regulators will take such reasonable steps as may be necessary to preserve investor rights to a fair return on and of their capital. Because of this special level of regulatory protection, investors provide capital to regulated businesses on more favorable terms (lower pricing) than would be the case for unregulated entities.

One need only compare FortisBC credit spreads with those for Canadian generic "A" 3-year spreads to see the benefits of the company's regulatory environment. As illustrated in the chart below, over the past 10 years FortisBC's corporate spreads have almost always compared favorably with generic A-rated spreads.

Fortis BC vs. Canadian Generic "A" 30-Year Spreads



21.2 Ms. McShane states in her evidence that regulation is intended to be a surrogate for competition (Appendix F, p. 72). Is it an appropriate role for the regulator to be protecting the bondholders return on and of capital compared to setting a fair, forward looking ROE and capital structure, and if so, why?

Response:

It is appropriate because the fair return standard applies to all capital, not just equity.

22.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, pp. 43-44, 50

Government of Canada Bond Yields and Cross Border Investment

On page 50, Aaron M. Engen's Opinion Evidence states "Canadian companies compete for capital with non-Canadian issuers investment opportunities."

The following table is based on 2009 to 2011 data from Figure 18 – Net Cdn. Purchases of Foreign Stocks and Figure 19 – Net Foreign Purchases of Cdn Stocks.

Year	Net Cdn Purchases of Foreign Stocks (C$ Billions)	Net Foreign Purchases of Cdn Stocks (C$ Billions)
2009	$15.9	$26.2
2010	$13.5	$18.2
2011	$26.3	$21.1
Average since 2009	***$18.6***	***$21.8***

22.1 Please confirm, or update otherwise, that the above table is accurate based on Figure 18 and Figure 19 in Mr. Engen's Opinion Evidence.

Response:

Confirmed.

22.2 Mr. Engen's opinion is that "Canadian companies compete for capital with non-Canadian issuers investment opportunities." Given that the average Net Foreign Purchases of Canadian Stocks at $21.8 million is higher than the Net Canadian Purchases of Foreign Stocks at $18.6 million, would Mr. Engen agree that Canadian companies raising capital in recent years have benefited from foreign investor participation?

Response:

Not necessarily. The vast majority of the net stock purchases identified in Figures 18 and 19 would primarily relate to secondary market trading activity. As the source of capital for Canadian companies, new issues would represent only a very small portion of the overall net purchases of Canadian stocks. The information required to conclude whether Canadian companies have benefited from foreign investor participation in new issues to raise capital is not available.

23.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, p. 46

Cross Border Issuance

On page 46 of Mr. Engen's testimony, Mr. Engen states that "Significant offerings of Canadian securities outside Canada are expected to continue and, in the case of the energy infrastructure sector, to grow…".

23.1 Please provide an industry sector allocation of Canadian corporate equity and bond issuance / offerings outside of Canada for each of the last 10 years.

Response:

The following table summarizes the industry allocation of Canadian equity offerings outside of Canada.

Equity										
Sector	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Agriculture	--	--	--	--	--	--	--	--	0.1%	38.2%
Diversified	10.9%	35.4%	12.7%	29.7%	13.5%	14.8%	2.9%	8.1%	39.6%	5.2%
Financial Services	3.4%	2.4%	6.0%	4.2%	5.1%	2.3%	51.3%	15.8%	19.8%	--
Healthcare & Biotech	1.3%	7.1%	3.9%	9.4%	3.7%	1.4%	0.4%	1.1%	0.3%	--
Infrastructure	--	--	--	--	--	--	--	--	--	2.1%
Media & Telecom	37.4%	8.5%	14.6%	2.1%	1.0%	0.5%	--	0.4%	--	0.6%
Mining	10.7%	25.6%	17.4%	23.2%	47.3%	44.6%	20.8%	46.8%	16.5%	12.6%
Oil & Gas	4.8%	13.4%	27.5%	30.0%	17.6%	13.2%	15.2%	11.7%	15.8%	26.7%
Paper & Forestry	3.8%	--	1.4%	--	--	--	1.0%	2.9%	0.1%	0.3%
Real Estate	2.2%	4.6%	4.3%	0.2%	9.2%	0.4%	0.7%	2.7%	4.3%	5.7%
Structured Products	--	--	--	--	--	1.5%	0.0%	2.3%	0.5%	2.1%
Technology	25.4%	1.3%	10.5%	0.9%	2.5%	7.2%	0.3%	1.3%	2.0%	0.1%
Utilities & Pipelines	--	1.8%	1.8%	0.3%	--	14.0%	7.4%	6.8%	0.8%	6.3%

The following table summarizes the industry allocation of Canadian debt offerings outside of Canada.

Debt										
Sector	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Diversified	14.2%	14.7%	20.4%	10.2%	26.1%	5.7%	6.4%	12.5%	14.7%	3.3%
Financial Services	3.7%	11.0%	11.2%	54.4%	25.1%	38.0%	37.1%	22.8%	53.9%	66.3%
Healthcare & Biotech	3.7%	--	0.7%	--	3.6%	--	0.8%	--	0.7%	3.2%
Media & Telecom	13.5%	16.1%	21.5%	2.7%	9.5%	9.8%	18.8%	8.5%	3.9%	1.1%
Mining	18.8%	15.5%	4.1%	13.5%	--	--	4.5%	26.6%	8.2%	14.2%
Oil & Gas	33.9%	21.0%	21.0%	11.8%	19.1%	35.0%	17.8%	18.7%	10.6%	10.1%
Paper & Forestry	5.5%	15.0%	12.2%	4.7%	0.5%	--	2.6%	4.1%	2.0%	--
Real Estate	1.3%	2.1%	1.1%	--	--	--	--	--	--	--
Technology	--	--	3.4%	1.2%	12.2%	--	2.3%	--	--	--
Utilities & Pipelines	5.3%	4.6%	4.4%	1.5%	4.0%	11.5%	9.8%	6.8%	6.2%	1.9%

23.2 Please provide the value and percentage of respective equity offerings and bond issuances that have been made outside of Canada for each of the last 10 years, for the following companies: Fortis Inc., Gaz Metro/Valener, TransCanada, Enbridge, Emera, and CU.

Response:

The table 1 which follows summarizes equity issuances offered outside of Canada by the referenced groups of companies. Table 2 summarizes debt offerings offered outside Canada by the referenced issuers.

Table 1

Equity Issuances											
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Cumulative
CU											
Offered Outside Canada											--
Total Offerings											--
Percent											--
Emera											
Offered Outside Canada											--
Total Offerings	$156									$202	$357
Percent	--									--	--
Enbridge											
Offered Outside Canada											--
Total Offerings	$232					$523					$755
Percent	--					--					--
Fortis											
Offered Outside Canada						$1,301				$341	$1,642
Total Offerings	$98	$350		$130		$1,301	$300			$341	$2,520
Percent	--	--		--		100%	--			100%	65%
TransCanada											
Offered Outside Canada						$1,725	$2,425	$1,840			$5,990
Total Offerings			$280			$1,725	$2,425	$1,840			$6,270
Percent			--			100%	100%	100%			96%
Valener / Gaz Metro											
Offered Outside Canada									$41		$41
Total Offerings		$81		$69					$41		$191
Percent		--		--					100%		21%

Table 2

Debt Issuances											
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**Cumulative**
CU											
Offered Outside Canada											--
Total Offerings	$200		$480	$185	$320	$255	$325	$270	$125	$700	$2,860
Percent	--		--	--	--	--	--	--	--	--	--
Emera											
Offered Outside Canada											--
Total Offerings	$90	$300		$250			$150	$725	$300	$250	$2,065
Percent	--	--		--			--	--	--	--	--
Enbridge											
Offered Outside Canada				$368		$894	$814				$2,077
Total Offerings	$300	$300	$200	$1,018	$1,125	$1,094	$1,314	$1,500	$2,100	$700	$9,652
Percent	--	--	--	36%	--	82%	62%	--	--	--	22%
Fortis											
Offered Outside Canada			$196			$211					$407
Total Offerings			$736	$100	$210	$316	$100	$530	$225	$225	$2,442
Percent			27%	--	--	67%	--	--	--	--	17%
TransCanada											
Offered Outside Canada		$475	$845		$578	$2,110	$1,566	$2,368	$2,342	$499	$10,783
Total Offerings		$925	$1,045	$300	$1,278	$2,110	$2,066	$3,068	$2,342	$750	$13,884
Percent		51%	81%	--	45%	100%	76%	77%	100%	67%	78%
Valener / Gaz Metro											
Offered Outside Canada										$265	$265
Total Offerings		$125			$300		$150	$100		$265	$940
Percent		--			--		--	--		100%	28%

24.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, p. 48

Structural Developments / Cross Border Activity

On page 48 of Mr. Engen's testimony, Mr. Engen states that "The growth of the maple bond market evidences the globalization of the Canadian debt capital market and signals increased competition for Canadian-issued debt capital."

24.1 What has been the industry allocation of the maple bond market?

Response:

As requested, the following table summarizes maple bond issuances by industry.

Canadian Maple Bond Issuances by Industry (Jan 2006 - July 2012)

Industry	Size	Percent
	(C$mm)	(%)
Auto Finance	$400,000,000	0.7%
Bank	$38,315,000,000	69.8%
Financial	$10,615,000,000	19.3%
Industrial	$750,000,000	1.4%
Infrastructure	$225,000,000	0.4%
Media & Telecom	$600,000,000	1.1%
Oil & Gas	$1,200,000,000	2.2%
Pipelines & Utilities	$1,325,000,000	2.4%
Real Estate	$350,000,000	0.6%
Retail	$1,100,000,000	2.0%
Total	$54,880,000,000	100.0%

24.2 What is the size of the maple bond market issuance as a % of total Canadian bond issuance over the last 10 years?

Response:

The following table summarizes maple bond issuance in Canada since 2006. As discussed in Mr. Engen's written evidence, the foreign property rule was not eliminated until 2005 and it was only on the elimination of the rule that foreign issuers began offering bonds in the Canadian debt capital market.

	2006	2007	2008	2009	2010	2011
Maple Issuance	$21,660	$18,300	$200	$500	$4,375	$2,800
Total Corporate Issuance	$78,871	$78,382	$60,740	$55,752	$73,925	$76,918
% of Market	27.5%	23.3%	0.3%	0.9%	5.9%	3.6%

24.3 Please describe the relative changes in the size of the maple bond market over the course of time.

Response:

Maple bond issuance began with a strong start in 2006 after the repeal of the foreign property rule and continued at a strong pace in 2007. In the face of the 2008-2009 market crash, maple bond issuances all but disappeared. Beginning in 2010 maple bond issuance improved but has not yet begun to return in any meaningful manner to pre-market crash levels.

25.0 Reference: Opinion Evidence of Aaron Engen

Exhibit B1-9-6, Appendix E, p. 53, and Appendix G, Evidence of Dr. Vander Weide, p. 7

Acquisition Price to Book / Rate Base to Book Value Ratios

On page 53, Mr. Engen says that "…rate base growth can be cited as a supporting reason for regulated asset purchase prices which may result in elevated purchase price-to-book ratios. When purchasers expect substantial rate base growth, they consider the purchase price in the context of aggregate rate base investment over the life of the asset including the initial purchase price and all additional capital to be invested in the asset."

On page 7 of Dr. Vander Weide's evidence, Dr. Vander Weide states that "From an economic perspective, a firm should only invest in a specific project if the expected return on the investment is greater than or equal to the company's cost of capital. Thus, the cost of capital serves as a hurdle rate for the firm's investment decisions."

Averch and Johson in their paper in the American Economic Review (Exhibit A2-10) said that:

> "In the present study the problem of rate-base inflation is not viewed as one of valuation but rather as one of *acquisition* – quite apart from the problem of placing a valuation upon the rate base, the firm has an incentive to acquire additional capital if the allowable rate of return exceeds the cost of capital." (Averch, Harvey, and Leland L. Johnson. "Behavior of the Firm under Regulatory Constraint," American Economic Review, vol. 52, no. 5 (December 1962), 1052-69)

25.1 To what extent is Dr. Vander Weide's statement that a firm should only invest in a specific project if the expected return on the investment is greater than or equal to the company's cost of capital, when viewed in conjunction with Mr. Engen's statement about rate base growth and purchasers of regulated assets, a demonstration of the Averch-Johnson effect?

Response:

Nothing about either Dr. Vander Weide's statement or Mr. Engen's evidence demonstrate the Averch-Johnson effect.

Regardless of the regulated asset acquirer's cost of capital or what it is relative to allowed ROEs, expanding rate base mathematically reduces the purchase price-book-value ratio as discussed in Mr. Engen's evidence. If the acquired rate base is expected to grow significantly as, for example, was the case with AltaLink, any premium paid at the outset can become immaterial. In such a case, the acquirer can pay a premium to win the asset knowing that in the long run, the premium will not be material.

This also means that an acquirer with a cost of capital equivalent to a regulated asset's allowed ROE can still pay a premium knowing that with enough rate base growth, expected returns will fall within the range of allowed ROEs. This, of course, ignores other tools available to the acquirer which can increase acquisition returns.

26.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, Table 2 – Cdn Energy Infrastructure Company Trading Comparables, p. 57

Price to Book Ratios

On page 57, Mr. Engen provides a Table 2 – Cdn Energy Infrastructure Company Trading Comparables includes a column for Price to Book values. Fortis has a current price to book ratio of 1.8x. The price was at 04-Jul-12.

26.1 What is the relative size of the British Columbia natural gas regulated companies (FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc, FortisBC Energy (Whistler) Inc.) relative to the parent Fortis Inc. Please state the relevant metrics (e.g. earnings, revenue, rate base, etc.) and the calculations.

Response:

The following ratios are based on 2011 consolidated revenues, assets, and earnings and 2012 forecast mid-year rate base FortisBC Energy regulated gas business:

	Revenues	Assets[1]	Earnings[2]	Rate Base[3]
Fortis Inc. Consolidated ($millions)	3,747	12,005	379	8,700
FortisBC Energy (regulated gas) ($millions)	1,568	4,408	139	3,575
FortisBC Energy (regulated gas) (%)	42	37	37	41

Notes:

[1] Tangible Assets do not include $1.6B of consolidated goodwill of which $908M is associated with FortisBC Energy

[2] Operating earnings before corporate costs of $61K

[3] Forecast mid-year rate base for 2012

26.2 What is the relative size of the regulated cost of service rate base of Fortis companies relative to Fortis Inc.? Please state the relevant metrics (e.g. earnings, revenue, rate base, etc.) and the calculations.

Response:

The following ratios are based on 2011 consolidated revenues, assets, and earnings and 2012 forecast mid-year rate base of Fortis regulated gas businesses:

	Revenues	Assets[1]	Earnings[2]	Rate Base[3]
Fortis Inc Consolidated ($millions)	3,747	12,005	379	10,941
Fortis regulated businesses ($millions)	3,490	10,758	338	8,700
Fortis regulated businesses (%)	93	90	89	80

Notes:

[1] Tangible Assets do not include $1.6B of consolidated goodwill (all of which is associated with regulated businesses)

[2] Operating earnings before FTS corporate costs of $61M

[3] Year end 2011 consolidated capital (equity, minority interest and debt) to forecast mid-year 2012 rate base

26.3 Based on the above calculations, what does Mr. Engen calculate as the implied Price to Book ratio for FortisBC Energy Inc. based on the publicly traded stock price of Fortis Inc. as at July 4, 2012?

Response:

The implied price to book ratio for all of Fortis Inc.'s businesses and divisions would be the same as that of the publicly traded entity (1.8x, as of July 4, 2012).

27.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, Table 4- Example Regulated Asset Purchase, p. 60

Accretive Acquisition; Effect on P/E

On page 60, Mr. Engen provides an example of a hypothetical regulated asset purchase.

27.1 In Table 4 - Example Regulated Asset Purchase there is a line "Assumption of Debt $1,625.0." Is this assumption of debt at book value of debt or market value of debt?

Response:

The debt would be assumed at its book value. When an buyer acquires a company and assumes the target company's debt, it is assuming the payment obligations associated with the debt which are based on its book value.

27.2 The example in Table 4 shows a "New Issue Share Price" of $31.59. Does the public share price of Emera fall from $33.79 to $31.59? If not, what is the expected share price of Emera immediately post-acquisition, all other factors being equal?

Response:

There is no reason to expect Emera's share price would drop as a result of the acquisition. To the contrary, assuming Emera maintained its current P/E ratio (19.9x), its share price could be expected to rise (all other factors being equal) to $34.42 following the acquisition as a result of its increased earnings per share ($1.73 x 19.9 = $34.42). Moreover, if the acquisition is seen by the market as bringing other advantages to Emera such as geographic diversification, establishment of a strategic foothold in a new market, it protects Emera's current business, or is expected to generate additional growth opportunities for Emera, it may reward the company with a higher P/E trading multiple after the acquisition, commonly referred to as multiple expansion. In such a case, Emera's share price would be expected to rise to levels higher than the pro forma $34.42 share price described above.

27.3 In the example the acquiring company had a P/E ratio of 19.9x. Based on the example it appears the acquirer purchased the target company at a P/E of 17.4x (1443.8/83.1). Mr. Engen explains this was accretive to earnings per share for the acquirer.

27.3.1 Generally, if an acquiring company has a higher P/E than the target company, all else being equal, would this be accretive to earnings per share for the acquiring company? Please explain.

Response:

Yes. Other things being equal, if the P/E ratio of the acquiring company is higher than the acquisition purchase price implied P/E ratio (in the example at hand, the purchase price ($1,443.8) / asset earnings ($83.1)), the transaction will be accretive to the acquiror's EPS. This is because the acquirer will be paying less for each dollar of earnings than the market values its own earnings. As a result, the acquirer will issue proportionately less shares to finance the acquisition. Mathematically, pro forma earnings from the acquisition, which equals the acquiror's earnings plus the target's earnings (the numerator in EPS) will increase more than its pro forma number of issued and outstanding shares (the denominator in EPS), causing EPS to increase.

27.3.2 Generally, if an acquiring company has a lower P/E than the target company, all else being equal, would this be dilutive to earnings per share for the acquiring company? Please explain.

Response:

Yes. Other things being equal, if the P/E ratio of the acquiring company is lower than the acquisition purchase price implied P/E ratio (in the example at hand, the purchase price ($1,443.8) / asset earnings ($83.1)), the transaction will be dilutive to the acquiror's EPS. This is because the acquirer will be paying more for each dollar of earnings than the market values its own earnings. As a result, the acquirer will issue proportionately more shares to finance the acquisition. Mathematically, pro forma earnings from the acquisition, which equals the acquiror's earnings plus the target's earnings (the numerator in EPS) will increase less than its pro forma number of issued and outstanding shares (the denominator in EPS), causing EPS to decline.

28.0 Reference: Opinion Evidence of Aaron M. Engen

Exhibit B1-9-6, Appendix E, pp. 65, 66

Pension Fund Foreign Investment

Mr. Engen provides a select list of Non-Canadian Infrastructure Investments on page 65, which includes Puget Energy. Mr. Engen comments that the Puget Energy acquisition in 2009 is particularly noteworthy.

28.1 Please elaborate on the investment merits, corporate structure, risk, and expected return on investment of the 2009 acquisition of Puget Energy.

Response:

Investment Merits

Mr. Engen understands that the chief investment merits which drew the investor consortium to acquire Puget Energy included:

- stable cash flows from the company's regulated businesses
- significant ongoing capital expenditure requirements (expected to be $5 billion over the five years following the acquisition) leading to significant rate base growth
- strong regional economy with expected future growth
- well established business with an experienced and respected management team

Mr. Engen expects that an additional investment merit would have been that the expected returns from the acquisition would have met with the buyers' acquisition target returns. Because expected returns on the acquisition cannot be known, however, he did not include it as one of the listed investment merits.

Corporate Structure

The following chart illustrates Puget's corporate structure, to the extent such information is publicly available.

Macquarie Infrastructure Partners I
Macquarie Infrastructure Partners II
Macquarie Capital Group Limited
Macquarie-FSS Infrastructure Trust
Canada Pension Plan Investment Board
British Columbia Investment Management Corporation
Alberta Investment Management Corporation

↓

Puget Holdings LLC

Indirect Ownership

↓

Puget Energy, Inc.

↓

Puget Sound Energy, Inc.

↓

Lines of Business:
Electric Generation, Transmission, and Distribution
Natural Gas Distribution

<u>Risk</u>

Puget Energy's business and risks are best described in the company's 2011 Form 10-K filed with the U.S. Securities and Exchange Commission.

A copy of Puget Energy's Form 10-K for 2011 is provided in Attachment 28.1.

<u>Expected Return on Investment</u>

The purchasing consortium did not publicly disclose its expected return on investment from its 2009 acquisition of Puget Energy. Whatever those expectations were, they were set in 2007 when the deal was struck to acquire the company, two years before receiving regulatory and shareholder approvals to close the transaction in 2009.

In addition, for reasons Mr. Engen discusses in his written evidence regarding utility acquisitions generally, because the consortium did not disclose its expected acquisition returns, observers cannot know or calculate the consortium's return expectations. This is so because observers lack knowledge of the consortium's financial assumptions and transaction structuring. And given what public disclosure has been made of the structure (the indirect ownership between Puget Holdings LLC and Puget Energy, Inc.), some or all of the acquisition financial structuring considerations Mr. Engen discusses in his written evidence could have been employed.

28.2 Please provide information on Puget Energy's achieved ROE and allowed ROE over the period 2002 to 2011.

Response:

The requested information is provided in the table below. Achieved returns for 2002-2009 are not available.

Year	Allowed ROE	Equity Thickness	Return on Capital	Achieved ROE
2002	11.0%	40.0%	8.8%	n/a
2003	11.0%	40.0%	8.8%	n/a
2004	11.0%	40.0%	8.8%	n/a
2005	10.3%	43.0%	8.4%	n/a
2006	10.3%	43.0%	8.4%	n/a
2007	10.4%	44.0%	8.4%	n/a
2008	10.4%	44.0%	8.4%	n/a
2009	10.2%	46.0%	8.3%	n/a
2010	10.1%	46.0%	8.1%	4.1%
2011	10.1%	46.0%	8.1%	6.9%

28.2.1 Please comment on the number of years where Puget Energy's achieved ROE was lower than the allowed ROE.

Response:

Achieved ROEs in 2010 and 2011 were lower than allowed ROEs for those years. Without knowing what the achieved ROEs were in the earlier years, Mr. Engen cannot say whether achieved ROEs in those periods were higher or lower than allowed ROEs.

It appears, however, that prior year ROEs were higher than those seen in 2010 and 2011. As the company states in its 2011 10-K, the "company has faced certain challenges which caused a **significant reduction in the return on equity as compared to other years**." [emphasis added] Moreover, recent performance has been affected by "regulatory lag". Again, as disclosed in the company's 10-K, the utility "rate making process has a delay between incurring expenses and their recovery in rate base." Mr. Engen understands there is currently a two-year regulatory cycle in Washington with the result that recent substantial capital expenditures (2011-$484 million) and expenses, which put downward pressure on the company's earnings, are not recoverable until after the following regulatory approval proceedings, at which time the company's earnings would increase.

Mr. Engen also understands that the company is working with the regulator to minimize regulatory lag in the future.

28.3 Please describe the characteristics that would make a US utility a desirable investment for a long term pension investor, and include discussion of realized and allowed ROE.

Response:

Mr. Engen advises that the key characteristics that would make a U.S. utility a desirable would include:

- stable earnings and cash flows supported by a rate regulated, cost-of-service regulatory environment
- attractive rate base growth
- well maintained assets
- strong and experience management team

Regarding realized and allowed ROEs, allowed ROEs are important to the extent they are a determinant of cash flows and returns. Higher allowed ROEs would generally be expected to produce higher cash flows and earnings over time. Realized or achieved earnings and cash flows are important because they define what investors are able to derive from the business (generally, cash flows).

Determining which is more attractive, a higher allowed ROE or a lower ROE, is a matter of expected returns.[4] Higher allowed ROEs with greater achieved ROE variability are more attractive than lower allowed ROEs with lower achieved ROE variability if the former produces a higher expected return than the latter.

[4] Weighted-average outcome.

29.0 Reference: Expert Opinion of Aaron Engen

Exhibit B1-9-6, Appendix E, p. 65

Market Required Return

On page 65, Mr. Engen says that "These target returns apply to investments in Canada as well as investments abroad. Again, like private equity, as important capital market participants with interest in energy infrastructure assets, the returns on capital pension funds seek for such assets are indicative of market required returns and should be taken into consideration as a "back-check" when setting allowed ROEs for regulated assets."

29.1 Regarding the statement that "…the returns on capital pension funds seek for such assets are indicative of market required returns….", does Mr. Engen mean to say that the target return for a pension fund is equal to the required return for a regulated utility? Please explain.

Response:

No. Rather, the returns on capital pension funds seek for regulated assets are indicative of the levels of returns the market seeks when acquiring such assets. In other words, they give a market-based context for required regulated asset returns.

30.0 Reference: Opinion Evidence of Mr. Aaron Engen

Exhibit B1-9-6, Appendix E p. 11 of 68; Appendix F p. 109

Price to Book Ratios and Allowed ROEs

Mr. Engen says that nothing can be learned about the appropriateness of allowed returns on equity from recent Canadian merger and acquisition activity involving regulated assets.

Mr. Engen further says that using strong share valuations to make smart, accretive acquisitions has nothing to do with whether the buyer is satisfied with the asset's allowed ROEs.

30.1 If Mr. Engen's expert opinion is valid, does it not refute the conceptual underpinnings of the discounted cash flow model (Ms. McShane's Testimony, p. 109) which proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of the cash flows?

Response:

No. To the contrary, Mr. Engen's position fully supports the conceptual underpinnings of the discounted cash flow model. Mr. Engen opposes the view that observers can draw conclusions regarding expected returns flowing from regulated asset acquisitions based only on the regulated asset's allowed ROE. Allowed ROE is one of many factors that drive expected cash flow from an investment in regulated assets. Other factors which can increase expected cash flows include changes in ROE, operating efficiencies, implementation of PBR regimes or increased benefits from current PBR regimes, and double dip interest deductibility.

In addition, regulated asset purchasers may have opportunities to increase cash flows away from the regulated business including access to other, higher ROE assets or businesses which are acquired alongside the regulated business, introduction of double leverage at a "holdco" level, and the opportunity to provide appropriately approved business services to the regulated business (engineering services, for example).

Rather than incorrectly considering one factor, allowed ROEs, when attempting to evaluate what returns buyers expect on acquiring a regulated asset, one should instead consider all sources of potential cash flows relevant to the purchaser at the time of the acquisition.

The difficulty, then, is that the foregoing information is not known to transaction observers. It is only known to the purchaser and its advisors. Because the information cannot be known by observers, any calculation of expected returns on capital from a regulated asset purchase will necessarily be incorrect.

31.1 Reference: Opinion Evidence of Mr. Aaron Engen

Exhibit B1-9-6, Appendix E p. 12 of 68; Exhibit A2-3 Brattle Group Report

Market Required Returns

In Mr. Engen's opinion, private equity and Canadian pension funds seek returns on equity of 10 percent or more when investing in energy infrastructure assets.

According to the Survey of Cost of Capital Practices in Canada conducted by the Brattle Group in May 2012, the most recent allowed ROEs in major Canadian jurisdictions are: Alberta (8.75 percent), Ontario (9.42 percent), Quebec (8.90 percent), Nova Scotia (9.2 percent), Newfoundland & Labrador (8.38 percent).

31.1 Does Mr. Engen's opinion apply only to a specific time or a specific energy utility or utility sector? Please explain the applicability of Mr. Engen's statement.

Response:

Mr. Engen's views on pension fund target returns are applicable in the current market. In the period leading up to the 2008-2009 market crash and for a period thereafter, pension fund target returns on equity for energy infrastructure direct investments increased and were closer to 15%. They apply to the energy infrastructure sector generally, regulated assets included.

Likewise, private equity target returns are applicable in the current market. During the 2008-2009 market crash private equity tended to be at the higher end of the 15%-20% range when considering investments in energy infrastructure assets, including regulated assets.

31.2 If Mr. Engen's statement is valid, please comment whether the funds of private equity and Canadian pension funds have divested from investment in regulated gas and electric utilities.

Response:

Mr. Engen is not aware of Canadian pension funds divesting themselves of their equity holdings in the Canadian energy infrastructure sector. The sector should be meeting their target returns since the average total return CAGR for all quarterly combinations over the past 20 years is over 13%.

31.3 While private equity and Canadian pension funds may "seek" returns on equity of 10 percent, is there any indication they are currently achieving such returns? Is it not the case that Canadian pension funds have been reducing their future equity return targets?

Response:

Pension fund target returns are an amalgam of returns from each pension fund's portfolio of various investments. Although Mr. Engen is not aware of whether pension funds have been reducing their future equity return targets, his ongoing work with Canadian pension funds respecting their interest in direct investments in/acquisitions of regulated assets demonstrates that their return targets remain as described in Mr. Engen's written evidence.

32.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Schedules 1 through 27

Schedules are presented in a format that is not readily accessible using Adobe search functions.

32.1 If possible, please send schedules in a format that is readily searchable.

<u>Response:</u>

A readily searchable Adobe version of the schedules is provided in Attachment 32.1.

33.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 12; Exhibit A2-16 Washington Utilities and Transportation Commission (WUTC) Order 08 to Puget Sound Energy Inc. (May 2012)

Relationship between Capital Structure and Return on Equity

On page 12, Ms. McShane states that "Thus, as the debt ratio rises, the cost of equity rises. As a result, the cost of equity, and thus, the fair ROE depends on the capital structure."

On page 65, Ms. McShane states that "The recommended ROE developed in Section VIII is premised on FEI pre-amalgamation as the benchmark BC utility, maintaining a deemed common equity ratio of 40.0%."

In the WUTC Order 08 Decision regarding the Puget Sound Energy Inc. (PSE) hearing, the WUTC says on page 3: "we determine that PSE's capital structure should be revised to include a 48 percent equity ratio, balanced with a 48 percent long-term debt ratio and 4 percent short-term debt…. In terms of capital costs, we reduce PSE's authorized rate of return on equity from 10.1 percent to 9.80 percent. These determinations, coupled with PSE's lower debt costs that are uncontested, provide lower rates to customers than might otherwise be the case while, at the same time, providing support to PSE by allowing the opportunity for PSE to earn an equity return on its full equity investment."

33.1 Do the FBCU agree with the WUTC that the allowed rate of return and the equity thickness are established to achieve different objectives for a regulated utility?

Response:

No, the FBCU are of the view that the ROE and equity thickness are established together to achieve a single objective, that is, to meet the fair return standard, which includes three requirements, comparable returns, financial integrity and the attraction of capital. For example, the equity ratio should set at a level that high enough to allow the utility to achieve a minimum "A" debt rating, which will allow access to the debt markets on reasonable terms and conditions in weak and robust capital markets.

33.2 Please indicate, by filling out the following table, which other combinations of capital structure and rate of return would provide a fair allowed ROE (for, say,

2011) based on the three tests used by Ms. McShane in her analysis. Please also justify the responses.

Capital Structure	ROE
35%	
36%	
37%	
38%	
39%	
40% (proposed)	10.5% (proposed)
41%	
42%	
43%	
44%	
45%	

<u>Response:</u>

As noted at page F-5 of Ms. McShane's evidence, "It is impossible to state with precision whether, within a specific range of capital structures, raising the debt ratio will leave the overall cost of capital unchanged or result in some decline. However, what is indisputable is that the cost of equity does change when the debt ratio changes." Ms. McShane's Appendix F discusses three approaches that can be used to estimate the change in the cost of equity as the capital structure changes. All are based on the simplifying, if unlikely, assumption that the cost of debt remains constant over the range of capital structures. The largest changes in the cost of equity occur under the first approach, which is based on the premise that the after-tax weighted average cost of capital is constant as the equity ratio changes. The smallest changes in cost of equity occur under Approach 2, premised on a decline in the after-tax cost of capital as the equity ratio declines. The third approach, which recognizes that, for utilities, the benefits of the corporate income tax deductibility of interest expense accrue to ratepayers, results in changes in the cost of equity for a given change in equity ratio that fall between those indicated by the other two approaches. The table below was prepared using Approach 3, whose results are virtually identical to the average of the results of Approaches 1 and 2. As the 10.5% ROE used as a point of departure was developed using a forecast 4.0% long-term Canada bond yield, the cost of new utility debt that is required to make the ROE estimates was based on the same forecast, i.e., the cost of new debt was estimated at 5.35%, reflecting a spread to the long-term Canada bond yield of 1.35%.

Capital Structure	ROE
35%	11.3%
36%	11.1%
37%	10.9%
38%	10.8%
39%	10.6%
40% (proposed)	10.5% (proposed)
41%	10.4%
42%	10.3%
43%	10.1%
44%	10.0%
45%	9.9%

34.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. Kathleen McShane

Exhibit B1-9, Appendix F, Appendix E, p. E-1

Comparable Earnings Test

Ms. McShane selected Canadian unregulated companies for her sample in the Comparable Earnings Test. She is of the view that unregulated companies generally are exposed to higher business risk and lower financial risk than the typical utility.

34.1 Apart from the fact that a typical utility is allowed a certain equity thickness, please provide support to the assertion that unregulated companies are exposed to lower financial risk than the typical utility.

Response:

As indicated on Schedule 24, the selected unregulated companies have equity ratios in excess of 70%, compared to Canadian utility equity ratios of approximately 40%. The unregulated companies also have much stronger credit metrics (e.g., EBIT coverage, EBITDA Coverage and Debt/EBITDA) than the utilities.

34.2 Please explain why Ms. McShane is of the opinion that the Comparable Earnings Test is entitled to significant weight given that: (a) the sample is composed of companies considered higher risk than FEI, (b) that unregulated companies' returns on equity tend to be cyclical which is unlike a typical regulated utility, and (c) the downward adjustment measure is so subjective.

Response:

In Ms. McShane's view, the comparable earnings test applied to unregulated companies is entitled to significant weight because of the combination of the following:

(1) The manner in which utilities are regulated (historical cost) and the ROE is set (on book value of equity). The comparable earnings test is the only test which measures returns in a manner compatible with the base to which they are applied.

(2) The comparable earnings test applied to other utilities would be a circular process, as the returns on book value expected to be earned by sample of regulated firms are themselves reflective of regulatory decisions.

(3) The fact that regulation is intended to be a surrogate for competition. In that context, the returns allowed for utilities should be commensurate with those available to companies of similar risk that are operating in a competitive market.

The fact that the companies are higher risk is addressed with the adjustment. All tests, including comparable earnings, ERP and DCF involve expert judgment, and in this case the expert judgment is exercised in the determination of an appropriate adjustment. The fact that all tests involve a measure of expert judgment is why it is important to use a variety of tests rather than reliance on a single test.

34.3 Which regulators in Canada, if any, have placed equal weight on the comparable Earnings Test (compared to CAPM and DCF) in the past 20 years? Please provide extracts from Canadian regulatory decisions that support giving equal weight to the Comparable Earnings Test.

Response:

Ms. McShane is not aware of any decisions in the past 20 years that have given equal weight to the comparable earnings test as compared to the CAPM and DCF.

34.3.1 Hasn't this test mostly been given minimal weight or viewed only as a "check" to the other tests (e.g., CAPM, DCF) in Canada?

Response:

Not confirmed. While not giving the Comparable Earnings Test equal weight, decisions have given weight to the comparable earnings results as shown below.

In RH-2-92 (2/93) for TransCanada PipeLines, the National Energy Board stated,

> *"Both the comparable earnings and equity risk premium techniques provided the Board with useful information in its determination of the appropriate rate of return to be allowed on TransCanada's deemed common equity component. However, the Board remains of the view that the results of the risk premium method should be given more weight than those of the comparable earnings method." (page 28)*

In E95070 (6/95) for the City of Edmonton, the Alberta Energy and Utilities Board stated,

> *“In arriving at a rate of return on common equity, the Board considers that, for the purposes of this Decision, all three tests of measuring common equity return are relevant. The Board does not agree with the opinion of the witness for the ERWCG, Mr. Kahal, that the comparable earnings test is of little help or relevance to these hearings because it does not attempt to measure the market cost of equity for the companies in the comparison sample. Rather, the Board considers that there is still some merit in the comparable earnings test to the extent that regulation is considered a surrogate for competition and the comparable earnings test attempts to measure the achieved accounting rates of return on common equity of enterprises of similar risk. The Board does, however, recognize that there may well be distortion in the market to book ratios caused by the effects of inflation on retained earnings of companies, notwithstanding their similarity in risk. Similarly, the comparable earnings test may be sensitive to the selection of the business cycle under study.” (page 43)*

The British Columbia Utilities Commission gave a small amount of weight to the comparable earnings approach in its December 16, 2009 decision, *In The Matter Of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. And Return On Equity And Capital Structure*, stating:

> *"The Commission Panel has considered the three approaches to determining ROE for a regulated utility and agrees with Terasen that it should take all three into account when establishing an ROE. The Commission Panel agrees that the DCF and ERP are the most common approaches used by regulatory agencies in the US and that CAPM has been widely used in Canada in the period since 1994. The Commission Panel has seen no evidence that suggests: i) it should ignore the fact that the Commission gave the DCF approach weight in the 2006 ROE Decision, or ii) that would persuade it to depart from the Commission’s finding in that decision that the CE methodology had not outlived its usefulness when it commented: “However, the Commission Panel is not convinced that the CE methodology has outlived its usefulness, and believes that it may yet play a role in future ROE hearings.” (pages 44-45)*

35.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. Kathleen McShane

Exhibit B1-9-6, Appendix F, p. 17

Bond Yields and Market Cost of Equity

Ms. McShane provides in her testimony her views of the protracted nature of the recovery from the global financial crisis and economic recession and of the recurrent bouts of capital market turbulence in the two years since 2009.

In Ms. McShane’s views, the trend in long-term Government of Canada bond yields is not indicative of the trend in the market cost of equity.

35.1 Given Ms. McShane’s assessment of the protracted nature of the recovery from the global financial crisis and economic recession since 2009, does Ms. McShane believe that certain investments such as the cost of equity in gas and electric utilities should be immune to financial crisis and recession proof? Why or why not?

Response:

The allowed return on equity is a function of the utility cost of equity. The utility cost of equity is an opportunity cost, which is in large part determined by the capital markets and capital market conditions. The utility cost of equity is not immune to those factors (financial crisis, impact of prolonged recession, market turbulence) referenced in the question.

35.1.1 Are Canadian utility stocks and bonds considered ‘safe-havens’ in the globalized financial markets? If not, why not?

Response:

Investment grade utility bonds in both Canada and the U.S. have benefited from the safe-haven status of the two countries, as investors have focused on fixed income securities. With respect to utility stocks, they generally are considered to be defensive securities, along with those of other defensive sectors, e.g., consumer staples and healthcare. As demand for their goods and services is more stable, defensive stock prices tend to hold up better than those of more cyclical sectors during weak economic conditions and down equity markets, and then move out of favour when the economy and capital markets improve.

35.1.2 Do the increases in the utility earnings multiples compared to the overall TSX market indicate they are "safe havens"?

Response:

The increases in utility earnings multiples are indicators of their defensive character, compounded by investors' search for yield in an environment of abnormally low interest rates. There is some concern in the market that utility stocks are overvalued based on high multiples relative to history in conjunction with their fundamental earnings prospects, with the attendant risk that when markets improve, there will be a sell-off in utility stocks.

36.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 20, Charts 1 and 2

Trends in Economic and Capital Market Conditions since 2009

On p. 20 of Ms. McShane's testimony, Ms. McShane provides two charts showing the yield spreads between 10 and 30-year Government of Canada bonds, and between DEX Long Corporate A Index and 30-year Government of Canada bonds.

36.1 Is Chart 1 based on the values found in schedule 2 of her evidence? If not please provide the supporting data.

Response:

Chart 1 is based on daily values of the 10 and 30 year Government of Canada bond yields. Schedule 2 has month end data, and quarterly and yearly averages of the monthly values. The supporting data for Chart 1 are provided in Attachment 36.1.

36.2 Please provide, in a single table, the data supporting Chart 2.

Response:

The 30 year Government of Canada bond yield data supporting Chart 2, which are month end data, are provided in Confidential Attachment 36.2. The DEX data underlying Chart 2 provided in response to this question are proprietary and under strict-use license. Therefore, the data are being provided confidentially under separate cover to the Commission only for the purposes of this proceeding, and cannot be provided to other parties under the terms of the license.

37.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 21 and pp. 26-27

Trends in Economic and Capital Market Conditions since 2009

On page 21 and pages 26 and 27, Ms. McShane discusses market volatility with reference to the Montreal Exchange volatility index (MVX) and the S&P/TSX 60 VIXC Index. Ms. McShane illustrates in Table 4 the performance of the VIXC index since October 1, 2009.

37.1 Please confirm that the description of the MVX provided on page 21 at footnote 19 also applies to the S&P/TSX 60 VIXC.

Response:

Both the MVX and S&P/TSX VIXC are described in footnote 19 on page 21. In the footnote, the S&P/TSX VIXC was described as follows: "The MVX was replaced by a **somewhat different measure of implied volatility**, called the S&P/TSX 60 VIX Index (VIXC), in October 2010, with historical data available from October 1, 2009. **Similar to the MVX, the VIXC measures the market's expectation of stock market volatility over the next month.**" [emphasis added]

37.2 Please provide a description of the Chicago Board Options Exchange volatility index. Please confirm that the CBOE VIX is a barometer of expected market volatility over the next 30 days.

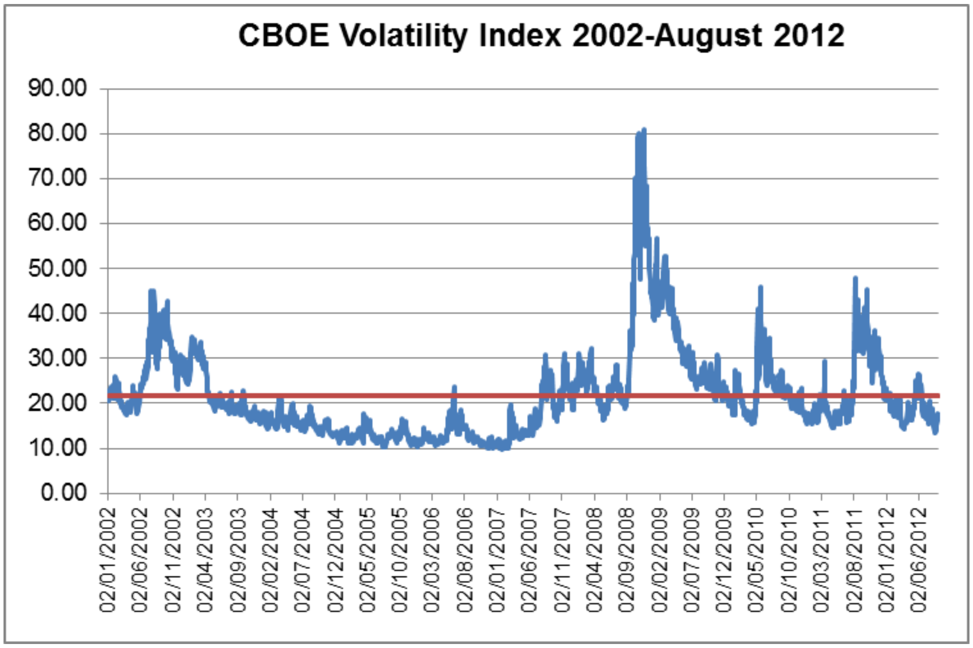
Response:

The Chicago Board Options Exchange ("CBOE") calculates various volatility indexes designed to measure the expected market volatility of various securities over the next 30 days. The most well known is the CBOE Volatility Index or CBOE VIX, which is intended to measure market expectations of near-term market volatility based on S&P 500 Index option prices.

37.3 Please provide a table showing the performance of the CBOE Volatility Index over the past 10 years.

Response:

A chart for the CBOE Volatility Index over the past 10 years similar to Chart 4 in Ms. McShane's testimony is presented below:



37.4 Does Ms. McShane agree that the S&P/TSX 60 VIXC and the CBOE VIX typically have an inverse relationship with the direction of the markets? That is, when the market is increasing the VIXC or the VIX would typically decline. If not, please explain why not?

Response:

Confirmed, the volatility indices typically have an inverse relationship with the direction of the markets.

38.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 31

Trends in Economic and Capital Market Conditions since 2009

On p. 31 of Ms. McShane's testimony, Ms. McShane says that "The recent downward trend in long-term Government of Canada bond yields has little, if any, correlation with trends in the market cost of equity. A comparison of equity market indicators points to a higher market cost of equity in mid-2012 versus at the end of the oral portion of the 2009 Application."

38.1 Please identify specifically which equity market indicators point to a higher market cost of equity in mid-2012 than at the end of the oral portion of the 2009 application, and why these indicators suggest that conclusion.

Response:

Please see the discussion at lines 775 to 791 on page 31 and Table 3 on page 32.

39.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 21 and 38

Trends in Economic and Capital Market Conditions since 2009/Business Risk

On page 21 of Ms. McShane's testimony (footnote 19), Ms. McShane discusses the MVX and the VIXC volatility indexes noting that they reflect investors' fears or expectations of stock market volatility over the next month. At p. 38, she says that "…it is the long-term business risks that are of primary concern to the investor."

39.1 If it is the case that it is long-term business risks that matter to the utility's investor, of what relevance are the MVX and the VIXC indexes if they are a reflection of investor sentiment over the next month?

Response:

While investors in utilities are primarily concerned with the long-term risks of the investment, the return at which they are willing to accept those risks is a function of the conditions in the capital markets at the time the investment is made. The VIXC (and its predecessor the MVX) is a gauge of how risk averse investors are, and thus is one indicator of trends in the equity market risk premium.

40.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 39-42

Business Risk

On pages 39-42 of Ms. McShane's testimony, Ms. McShane discusses the primary categories of utility business risk.

40.1 Would Ms. McShane agree that some proportion of those risks may be under the control of the company's management? If not, why not? If some proportion of those risks is considered to be within the control of management, then should investors be compensated for that proportion of the risk that is under management's control? If so, why?

Response:

Yes, Ms. McShane would agree that some risks may be under the control of management. With respect to whether investors should be compensated for risks under the control of management, a premise underpinning the determination of a fair return is that management acts prudently. Prudent management, in turn, contemplates that the governance of the firm would entail reasonable risk management strategies and policies. The utility shareholder should not be compensated for failure to undertake reasonable steps to manage risks. On the other hand, control of risks is not without cost. The costs of risk management must be balanced against the potential benefits. To illustrate, management can control the risk of financial loss from damage to the utility network by purchasing insurance. The cost of that insurance needs to be balanced against the likelihood of loss from such events.

41.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 42

Business Risk

On page 42, lines 1053-54 of Ms. McShane's testimony, Ms. McShane says "…the exercise of creating a risk by risk "scorecard" would not comport with the manner in which investors evaluate business risk. Investors appraise business risk on an overall aggregate basis, not by relying on a risk by risk checklist."

and

lines 1061-65 of Ms. McShane's testimony, Ms. McShane says that "The business risk assessment must be used in conjunction with other factors, both qualitative and quantitative, …in order to judge what constitutes a reasonable capital structure and, ultimately, how the overall risk of a utility compares to its peers."

41.1 In the circumstance of a utility with a regulated capital structure and rate of return, would a formal business risk assessment such as a scorecard not enhance the ability of the regulator to compare the utility to its peers? If not, why not?

Response:

Ms. McShane is of the view that the benefits to a score card approach to comparing business risk are limited for the reasons set forth at lines 1040 to 1045 of her testimony.

42.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 42

Business Risk

On page 42, lines 1070-71 of Ms. McShane's testimony, Ms. McShane says "An increase in common equity ratio may be warranted, even if there has been no change in business risk if, for example, investors have become more risk averse and require more conservative financial parameters for a given level of business risk. An increase in equity ratio may also be warranted if credit metrics are weakening due to diminished cash flows."

42.1 Is a decrease in the equity ratio warranted if and when conditions improve? If not, why not?

Response:

A decrease in equity ratio may be warranted, in the absence of a change in business risk, where there is clear and sustained evidence that investors would accept a lower equity ratio without impairing the utility's access to and cost of capital. There is no such evidence in the case of FEI. As noted, for example, at page 59 of Ms. McShane's evidence, Moody's considers FEI's credit metrics to be weak for its existing rating, which is at the lower end of the A category. Further, there is no evidence that FEI is able to issue debt on better terms and conditions with its existing capital structure than other similarly rated Canadian utilities.

43.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 41 & 66

Judgment used in determining business risk & ROE

On page 41 of Ms. McShane's testimony, Ms. McShane states that "The assessment of business risk is an inherently qualitative exercise, not amenable to quantification. There is no recognized methodology for isolating individual business risk factors and quantifying the corresponding required increment of common equity or ROE."

And at page 66 of Ms. McShane's testimony, Ms. McShane states "Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of ensuring that all three requirements of the fair return standard are met; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return. Changes to the inputs to individual tests may have different implications depending on the prevailing economic and capital market conditions. These considerations emphasize the importance of reliance on multiple tests."

Based on similar CAPM and DCF models, Ms. McShane and Dr. Booth have come up with very different "fair" ROE projections for BC utilities in the past.

43.1 To what extent do Ms. McShane's CAPM and DCF projections change as a result of her informed judgment applied to her statistical data? I.e. How much judgment does she apply to the statistical database?

Response:

Ms. McShane views her analysis and conclusions as the application of expert judgment to a broad set of data. She is unable to quantify the amount of expert judgment that is applied to the statistical base, but would describe it as material, as the estimation of a fair return is not a statistical exercise.

43.2 If Ms. McShane adopted Dr, Booth's assumptions for her CAPM and DCF tests would her results approximate those of Dr. Booth?

Response:

The question, as posed, appears to be in the nature of a tautology. If, hypothetically, Ms. McShane were to adopt Dr. Booth's assumptions, which presumably would then lead to Ms.

McShane adopting Dr. Booth's inputs, then the only logical conclusion would be that her estimates would be similar to his.

44.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 51, Chart 5

Business Risk of the Benchmark Utility FEI

Chart 5 shows the BC Residential market share of natural gas versus electricity based on Natural Resources Canada data.

44.1 Please provide tables and graphs showing, for each of the FCBU, the most recent long-range demand and customer forecasts prepared for LTRP, CPCN or other planning purposes.

Response:

Please refer to Attachment 44.1 for the requested tables and graphs.

The data presented is from the 2010 Long Term Resource Plan (LTRP).

Following the 2010 LTRP submission FEU was directed to adopt an end use methodology for the next long term forecast. The intention was to be able to more accurately model changing use rates for different end uses, and then to be able to design scenarios around those end uses. This work is underway and will produce an updated forecast for the 2013 LTRP filing. Since the 2010 forecast we have seen residential use rates continue to decline and residential construction continue to favour multi-family dwellings. Commercial volumes have remained stable while industrial volumes have increased. We expect the upcoming end use and scenario-driven long-term forecast to provide detailed insights into the consumption patterns for the various rate groups.

45.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 55-56

Business Risk of the Benchmark Utility FEI

In discussing regulatory risk, Ms. McShane states on page 55 that "More FEI activities, focused on new initiatives, are subject to regulatory oversight, entailing more frequent, protracted, and contentious proceedings. On page 56, Ms. McShane states that "The level of business risk, in the aggregate, to which FEI is exposed is at least as high as when it was last assessed in 2009."

45.1 How much of the possibly higher risk to which FEI is exposed is related to FEI's new initiatives?

Response:

The conclusion that the regulatory risk to which FEI is exposed is no lower, and in some ways higher than in 2009, reflects the overall uncertainty arising from energy policy, which must be considered in most applications before the Commission, and thus pervades the regulatory process. Since FEI's new initiatives are being developed to address declining natural gas throughput, driven in part by policy, it is in those areas where the increasing complexity and uncertainty in the regulatory environment have been most obvious. The clearest example, as pointed out by the FBCU in Appendix H to the Application, page 53-54, is the NGT service, first proposed in 2009, but which is still under consideration.

46.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 57

Business Risk of the Benchmark Utility FEI

Ms McShane states on page 57 that In August 2009, Moody's adopted a new framework for rating electric and gas utilities world-wide and that the methodology considers diversification (10% weight). In footnote 56, she says that: "For gas distribution utilities, diversification refers to market position, which reflects the diversity of markets among economic regions and regulatory regimes, the make-up of the customer base (e.g., dependence on industrial load) and growth potential. For electric utilities, the 10% weight attributed to diversification is split between market position (5%) and generation and fuel diversity (5%)."

46.1 Can an increase in diversification lead to a reduction in risk and an increase in the ratings framework? Would FEI's new initiatives referred to on p.55 constitute an increase in diversification? If so, does Ms. McShane expect that they will decrease risk, increase it, or leave it unchanged?

Response:

In principle, yes, diversification of activities can lead to an increase in the rating on that factor. In the case of FEI, Moody's refers to diversity of markets among regulatory regimes and economic regions; the activities to which the question refers are in the same economic region and subject to the same regulatory regime. Further, FortisBC is conducting its thermal energy activities in a separate subsidiary (FAES), until the AES Inquiry decision determines where this business will sit (class of service within FEI or continue within FAES). Regardless on a stand-alone basis, those activities do not contribute to the diversification or change the risk of FEI, the benchmark utility. The other principal initiative, natural gas for transportation, which is discussed at lines 1340-1344 of Ms. McShane's testimony, is an activity expected to be conducted within FEI, the natural gas distribution utility. This activity, if conducted within FEI as part of the natural gas distribution class of service, would lead to some diversification. However, as indicated at lines 1341-1342, over the next five years, the impact on FEI is expected to be very small relative to the total gas business. Over the longer-term, if there were to be further growth in the NGT business, it would be more likely to mitigate rising business risk due to trends in the core business than result in a reduction in business risk relative to where it stands today.

47.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 58, Schedule 15 pp. 1-2, Schedule 22; Apendix G Evidence of Mr. Vander Weide, p. 86

On page 58 of Ms. McShane's testimony, Ms. McShane displays Moody's ratings for eight key factors for FortisBC Energy Inc. Schedule 15 lists her selection of 12 comparable US utilities, Schedule 22 lists her selection of 5 comparable Canadian utilities.

On page 86 of Mr. Vander Weide's evidence, Mr. Vander Weide lists the allowed ROE of US utilities, which includes Puget Sound Energy Inc.

47.1 Please provide the ratings for the eight key factors for each of the 17 comparable US and Canadian utility companies listed by Ms. McShane, and for Puget Sound Energy Inc. as listed by Mr. Vander Weide.

Response:

The eight key factors for each of the utilities in Ms. McShane's U.S. utility sample are provided in Attachment 47.1. Enbridge Inc. and TransCanada Corp. are not included as Moody's uses different factors for rating pipelines than for rating gas and electric utilities. Canadian Utilities Limited, Emera Inc., and Fortis Inc. are not rated by Moody's. Puget Sound Energy Inc. was not included, as Ms. McShane does not have a subscription to Moody's and only purchased the Moody's reports for the utilities in her proxy samples.

47.2 Please provide the Moody's and Standard & Poor's ratings report for these 18 comparable US utility companies. (Please file the electronic version only if the reports are voluminous)

Response:

The question states there are 18 comparable U.S. utility companies. It is assumed these 18 are the 17 comparable U.S. and Canadian utility companies and Puget Sound Energy Inc. as stated in the question in BCUC IR 1.47.1. The Moody's ratings reports for the 12 comparable U.S. companies and the 2 Canadian companies rated by Moody's (Enbridge Inc. and TransCanada PipeLines) along with S&P reports for all 18 companies are provided in Attachment 47.2. As indicated in response to BCUC IR 1.47.1, Ms. McShane does not have a subscription to Moody's and does not have a Moody's report for Puget Sound Energy Inc.

47.3 Please provide any recent North American utility industry research reports by Moody's and Standard & Poor's. (Please file the electronic version only if the reports are voluminous)

Response:

The following reports have been provided in Attachment 47.3

Attachment 47.3a contains two Moody's reports:

- *Regulatory Frameworks - Ratings and Credit Quality for Investor-Owned Utilities,* June 18, 2010
- *Special Comment Canadian Rate-Regulated Entities Considering Conversion to US GAAP - Ratings Unlikely to be Impacted* - March 16, 2011

Attachment 47.3b contains seven S&P reports:

- *Standard & Poor's Updates Its US Utility Regulatory Assessments*, March 12, 2010
- *Sector Review: How Utilities Around the World are Coping with Regional Economies*, December 21, 2011
- *Top 10 Investor Questions About US Gas and Water Utilities in 2012*, February 9, 2012
- *Issuer Ranking: Canadian Utilities and Pipelines, Strongest to Weakest*, June 21, 2012
- *Industry Economic and Ratings Outlook: US Regulated Utilities Will Likely Stay on a Stable Trajectory for the Rest of 2012 and into 2013*, July 17, 2012
- *Issuer Ranking: US Regulated Utility Companies, Strongest to Weakest*, August 6, 2012
- *Implications of the Canadian Regulated Utility Sector's Mixed Bag of Accounting Standards*, August 31, 2012

47.4 The list of comparable US utilities submitted by Ms. McShane has changed from the prior proceedings. Please describe the reasons for each company's addition or removal from the lists since the 2005 proceedings.

Response:

The following tables identify the companies and screening criteria failed which lead to companies being excluded from samples of comparable utilities since the 2005 proceeding.

Changes between 2005 and 2012:

Integrys Group Inc. was formed in 2007 from the merger of Peoples Energy and WPS Resources. Both Peoples and WPS were in the 2005 sample; Integrys was included the 2012 sample.

Companies in 2012 Sample Not in 2005 Sample	
Company	***Reason***
Alliant Energy Corp.	Business risk profile above 5
Atmos Energy Corp.	S&P rating below A-
Wisconsin Energy Corp.	S&P rating below A-
Xcel Energy Inc.	S&P rating below A-
Companies in 2005 Sample Not in 2012 Sample	
KeySpan Corp.	Has merged into National Grid USA
New Jersey Resources	Utility assets < 80% of total assets.
NICOR Inc.	Has merged into AGL Resources
NSTAR	Has merged into Northeast Utilities
SCANA Corp.	Moody's rating below Baa1

Changes between 2009 and 2012:

Companies in 2012 Sample Not in 2009 Sample	
Company	*Reason*
Alliant Energy	S&P rating below A-
Atmos Energy Corp.	S&P rating below A-
Integrys Energy Group Inc.	S&P Business Profile not Excellent
Wisconsin Energy Corp.	S&P rating below A-
Xcel Energy Inc.	S&P rating below A-
Companies in 2009 Sample Not in 2012 Sample	
Dominion Resources	Moody's rating below Baa1
Duke Energy	Moody's rating below Baa1
FPL	S&P Business Profile not Excellent
New Jersey Resources	Utility assets < 80% of total assets.
NSTAR	Has merged into Northeast Utilities
SCANA Corp.	Moody's rating below Baa1

47.5 For all these US comparables selected by Ms. McShane in the past and present, please provide the following over the last 20 years; discussion of significant corporate developments, realized and allowed ROE, actual and allowed equity thickness, credit ratings, and brief summaries of regulatory decisions with regards to ROE and capital structure.

Response:

Please note that Appendix B to Ms. McShane's testimony contains significant detail on each of the utilities in her U.S. utility sample. Ms. McShane has attempted to provide as much of the information requested in this response as possible for the current sample given what is readily accessible, the time constraints and the effort required. She has not provided information for companies that are not in the sample, due not only to the undue burden that it would entail, but to its questionable relevance.

With respect to corporate developments for each of the 12 utilities, Attachment 47.5a contains a brief history of the major corporate developments of each of the 12 utilities.

Attachment 47.5b contains the earned returns for the 12 companies in the sample from 1992 to 2011.

With respect to allowed ROEs and equity ratios, Attachment 47.5c provides a history of the allowed ROEs and equity ratios for the major subsidiaries of each of the 12 companies from 1993 to current.

A history of the Moody's and S&P credit ratings for each of the 12 companies is provided in Attachment 47.5d.

Ms. McShane does not maintain a data base of U.S. utility decisions and providing the information requested would represent a very significant undertaking. The time, effort and expense involved to find, review and summarize twenty years of decisions for each of the utilities are not warranted given the limited value of the information in the context of Ms. McShane's evidence.

48.0 Reference: Testimony of the Cost of Capital for the FBCU by Ms. Kathleen McShane

Exhibit B1-9-6, Appendix F, pp. 62-63

Allowed Capital Structure Ratios

Ms McShane opines that in the 2009 ROE application, the reasonableness of FEI's proposed 40% equity ratio was evaluated partly by reference to trends in the capital structures of its peers. Ms. McShane further describes that since the end of the oral portion of the 2009 ROE application, there have been a number of increases in the deemed common equity ratios adopted for other ex-BC Canadian utilities with which FEI competes for capital.

In Ms. McShane's testimony, Ms. McShane also states, on page 63, that lower ROEs and tax rates required an increase to maintain credit metrics at the same level as in 2004, the previous cost of capital proceeding.

48.1 Does continued reference to trends in the capital structures of FEI's peers introduce the element of circularity into the review of its capital structure?

Response:

Unavoidably, yes, there is some circularity. However, the comparisons to the capital structures of other utilities are required to understand whether a particular utility's capital structure is in line with industry practice and whether, in conjunction with an appropriate ROE, the resulting return would meet the requirements of the fair return standard.

48.2 Please explain why a lower tax rate would require an increase to maintain credit metrics at the same level previously determined.

Response:

Section XI.A of Ms. McShane's evidence discusses the impact of non-taxability on credit metrics. The same phenomenon is applicable at relatively low income tax rates. All other things equal (e.g., embedded cost of debt, ROE, capital structure ratios), as the income tax rate declines and the income tax allowance forms a relatively smaller portion of Earnings before Interest and Taxes (EBIT) and Earnings before Interest, Depreciation and Amortization (EBITDA), the pre-tax credit metrics, e.g., EBIT Interest Coverage, EBITDA Interest Coverage and EBITDA to Debt, will be weaker.

As a simple illustration, assume the following: An embedded cost of debt of 6.5%, an ROE of 9.5%, 60% debt/40% equity and a rate base of $1,000. At a corporate income tax rate of 44%, as it was in the mid-1990s, the illustrative EBIT interest coverage would be approximately 2.74X. The corresponding EBIT Interest Coverage at the prevailing income tax rate in BC of 25% is approximately 2.3X. The table below shows how the calculations were done.

	EBIT Interest Coverage Illustration at Different Tax Rates			
Tax Rate	(1)		44%	25%
Rate Base:	(2)		$1,000	$1,000
Debt	(3)	(2) * 60%	$600	$600
Equity	(4)	(2) * 40%	$400	$400
Interest Expense at 6.5%	(5)	(3) * 6.5%	$39.0	$39.0
ROE at 9.5%	(6)	(4) * 9.5%	$38.0	$38.0
Income Tax Allowance	(7)	(6) * (4)/(1-(4))	$29.9	$12.7
EBIT	(8)	(5) + (6) + (7)	$106.9	$89.7
EBIT Interest Coverage	(9)	(8)/(5)	2.74	2.30

49.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. Kathleen McShane

Exhibit B1-9-6, Appendix F, pp. 63-65; Exhibit A2-14 Allowed Capital Structure of Small Utilities; Exhibit A2-15 Credit Rating and Investment Banks Reports Summary

Reasonableness of Capital Structure

Ms. McShane says that she agrees with FBCU's proposal that the equity ratio for FEI, the proposed benchmark BC utility, be established at a minimum of 40 percent. Ms. McShane supports her assessment based on current business risk of FEI as compared to 2009, Moody's credit rating, Moody's debt ratio guidelines, comparison with a number of Canadian utilities, and capital investment requirements for infrastructure in North America and globally.

Exhibit A2-14 shows the capital structure of a number of regulated projects recently awarded 60/40 debt/equity capital structure by the Commission; Exhibit A2-15 highlights the descriptions of FEI (or Fortis Holdings, if applicable) by credit rating agencies and investment banks in their reports.

49.1 Do the FBCU agree with the information in Exhibits A2-14 and A2-15? If not, please modify the tables in your response.

Response:

The information contained in Exhibit A2-15 has been accurately cited from the sources.

49.2 Do the FBCU agree that currently many developments, district energy systems, and small utilities have equity ratios at 40 percent which is equivalent to FEI, the benchmark utility?

Response:

Yes, current allowed equity ratios for entities noted in the question are 40%, but in the FBCU's view, these equity ratios are likely too low for their risks. In this regard, the FBCU note the expert evidence filed by Ms. McShane in the Common Rates, Amalgamation and Rate Design proceeding (Exhibit B-3, Appendix C-2 of that proceeding) in which she assessed the long-term business risks of FEVI and FEW and concluded that reasonable equity ratios for these two utilities were 45%. The FBCU also note the recently filed Kelowna District Energy System Project CPCN Application, at page 63, where FAES concluded that:

"FAES is of the view that the Kelowna DES exhibits these factors and requires a higher cost of capital than the benchmark utility. To date the higher risk has been addressed through an ROE risk premium. Based on the evolution of these projects, FAES believes that the higher risk for these TES projects needs to be factored into the equity thickness for these projects. It is FAES position that the 40% equity thickness that FAES or FEI has been using in these projects to date is too low."

Please also refer to the response to BCUC IR 1.49.5.

49.3 Do the FBCU agree with Moody's assessment that gas LDCs are at the low end of the risk spectrum within the universe of regulated utilities? And regulated gas LDCs like FEI to be among the lowest risk corporate entities?

Response:

As it is not clear how Moody's arrived at that conclusion (i.e., whether it ranked sectors or considered the number of utilities in each sector, or which sectors Moody's includes in its assessment), it is not possible to agree or disagree. If the ranking is among the four main utility categories identified by Ms. McShane at pages 45 to 48, i.e., electric transmission, electric distribution, gas distribution and vertically integrated utilities, then no, the FBCU do not agree. With respect to Moody's statement that regulated gas LDCs like FEI are among the lowest risk corporate entities, the statement was made in the context of business risk. The FBCU would agree that gas LDCs have lower business risk than most other corporate sectors.

49.4 Do the FBCU agree with Moody's and DBRS that the many deferral accounts allowed by the Commission significantly benefit FEI compared to companies without such support?

Response:

The FBCU are not aware that either DBRS or Moody's has, in the reports referenced in the question referred to either "many" deferral accounts, or that either has said that the deferral accounts allowed to FEI significantly benefit FEI compared to companies without such support. The FBCU acknowledge that FEI's deferral accounts provide a benefit in terms of reducing short-term forecast risk. Many other North American utilities have mechanisms that mitigate forecasting risk.

49.5 Do the FBCU regard a 40 percent equity ratio for a low risk utility such as FEI reasonable compared to the smaller systems described in Exhibit A2-14? Please explain.

Response:

In Ms. McShane's view, using the small utilities' deemed capital structures as a reference point for assessing FEI's capital structure is inapposite, since the capital structure of FEI has been assessed independently by debt rating agencies, and those of the small entities referenced have not. In relation to FEI's capital structure, the deemed common equity ratios of the small referenced utilities are likely too thin, even considering that they have been allowed a risk premium over that applicable to the benchmark utility, i.e., FEI.

49.6 Holding everything else constant, please demonstrate how a 38 percent equity ratio for FEI would weaken FEI's cash flow interest coverage below 2.3x and CFO pre-WC/Debt below 8 percent?

Response:

Based on its 2011 annual financial statements, FEI has estimated the two ratios to be 2.6x and 10.8%. The ratios reflect actual ROE and common equity. Starting with the 2011 results, FEI has adjusted only for a reduction in the deemed common equity of 2%, as requested in the IR above. The adjusted ratios are estimated to be 2.5x and 10.2%.

The question seems to be assessing whether a reduction in equity ratio could breach threshold ratios that could lead to a downgrade. While a reduction in equity as presumed would not have a significant impact on the ratios, a decision to reduce the equity ratio by the regulator, in light of the trend toward thicker equity ratios in other Canadian jurisdictions in recent decisions, and Moody's expectation of stronger metrics than historically, may be viewed as undermining the regulatory support that in part has supported the FEI rating in the face of traditionally weak financial metrics.

49.7 Do the FBCU agree with BMO's assessment that FEI's spreads are reasonably valued?

Response:

The FBCU have no basis on which to disagree with BMO's assessment.

49.8 On page 64 of Ms. McShane's testimony, Ms. McShane says that capital investment requirements for infrastructure in North America and globally have grown to unprecedented levels, which points to significant competition for capital going forward. Is Ms. McShane including the riskier infrastructure projects in emerging markets such as toll roads in China and the railroads in Mexico in her description of requirements for infrastructure in North America and globally? Please provide data to support her assertion.

Response:

The statement on page 64, that "Capital investment requirements for infrastructure in North America and globally have grown to unprecedented levels..." was a synopsis of statements made earlier in Ms. McShane's testimony at page 37, lines 918 to 926 and associated footnote 47. Those comments were specific to energy infrastructure capital investment and consequently excluded the types of infrastructure projects referenced in the question.

49.8.1 Is FEI competing with high risk infrastructure projects in emerging markets for capital?

Response:

FEI would be competing for capital within the energy infrastructure sector globally, which would include emerging markets, and thus needs to provide investors with returns appropriate to its level of risk in order to attract and retain that investment. Please refer to the response to BCUC IR 1.49.8.

50.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 67

Fair ROE for FEI as Benchmark BC Utility

Ms McShane states on page 67 that the CAPM test is challenged by the fact that "…the model does not readily allow estimation of changes in the size of the market risk premium as economic or capital market conditions (e.g., interest rates) change. The typical application of the CAPM relies heavily on long-term average achieved equity risk premiums in conjunction with a current or forecast risk-free rate."

50.1 To what extent does it matter that changes in the short-term interest rate match changes in the market risk premium when investors are looking at investing in long-term assets?

Response:

Ms. McShane's discussion was not related to short-term interest rates. The discussion was in the context of long-term interest rates, specifically the long-term Government of Canada bond yield. The point was that it is not reasonable to assume that the market risk premium (which represents the difference between the equity market return and the risk-free rate) is equal to its long-term average when the prevailing and forecast risk-free rate is much lower than its long-term average. The CAPM does not readily allow estimation of changes in the size of the market risk premium as the risk-free rate, proxied by the long-term Canada bond yield, changes.

51.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 71, and Table 1 in App F to Ms. McShane's evidence

Fair ROE for FEI as Benchmark BC Utility

On page 71, Ms. McShane states that "Market values reflect returns that investors expect to earn over the longer-term, not the returns that regulators have historically or recently allowed."

51.1 Is Ms. McShane suggesting that investors largely ignore allowed returns? If so, can she provide any independent evidence to support that claim?

Response:

No. They do not ignore allowed returns. Allowed returns will certainly play a role in the returns that investors expect the companies to earn, but, as discussed at lines 1848 to 1863, there are many reasons why investors would expect the companies to earn returns that are higher than returns that have been allowed in the past or the most recently allowed return.

51.2 When considering the rate of return from regulated activities, to what extent should the analysis include or exclude returns achieved through non-regulated operations?

Response:

The objective is to estimate the return that investors require from regulated activities, but most publicly-traded utility companies have some unregulated activities, whose expected returns will be incorporated into the price of the stock. The prices of utility shares, in turn, are a key input into the estimation of the returns that investors expect. Consequently, the returns cannot be ignored, nor can they be "backed out" of both the price and the expected earnings. Please note that, based on the information provided in Appendix B of Ms. McShane's evidence, for the sample of U.S. utilities, approximately 93% of the assets (median basis) are regulated assets; the preponderance of the remainder are for operations that directly relate to the regulated activities.

52.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 72

Fair ROE for FEI as Benchmark BC Utility

On page 72, Ms. McShane says that "Regulation is intended to be a surrogate for competition. The competitive model indicates that equity market values tend to gravitate toward the replacement cost of the underlying assets. This is due to the economic proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, i.e., when the market value equals the replacement cost of the productive capacity of the assets."

52.1 How true is this proposition for a regulated energy utility where the franchise of the utility limits the utility to the product for which it has a monopoly, and limits the area where its monopoly applies? In other words does the parallel that Ms. McShane suggests with respect to behaviour of market to book ratios hold for regulated firms where, on one hand, competition is limited, and on the other where expansion outside of the utility's franchise area is also limited?

Response:

Yes, Ms. McShane is of the view that the parallel holds for regulated utilities. One of the key objectives of regulation is to mimic a competitive market outcome in industries whose characteristics (e.g., barriers to entry and demand) might otherwise allow them to earn monopoly profits. Under competition, equity market values tend to gravitate toward the replacement cost of the underlying assets. This is due to the economic proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, i.e., when the market value equals the replacement cost of the productive capacity of the assets. In the absence of inflation and technological gains, the market value of assets should approximate its book value. However, those caveats do not reflect reality, particularly, in the case of public utilities, where persistent inflation over time results in the book value of the assets understating their true economic value. When the regulatory paradigm is based on historical costs of the assets, but the allowed return represents a capital market-derived return applied to the book value of the equity, with the underlying premise for the allowed return is that the utility market value should equal book value, the resulting prices will understate the real economic costs of providing utility services and send price signals to customers that encourage overconsumption of scarce resources.

52.2 If the regulator of a utility, all of whose activities were regulated, and if the regulator historically had allowed below market returns, would Ms. McShane expect the market value of the utility to fall below the book value? If not, why not?

Response:

In theory yes, if the utility had not been able to earn, and was not expected to earn in the future, returns above the allowed returns and at least equal to what the market required. In practice, as the book value of the equity reflects accounting conventions, not necessarily economic value, that might not turn out to be the case.

53.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 75

Fair ROE for FEI as Benchmark BC Utility

Ms. McShane states on p. 75, that "To ensure comparability with the benchmark BC utility, only relatively pure-play U.S. utilities were selected."

53.1 By relatively pure-play U.S. utility does Ms. McShane mean that the selected utilities earnings were primarily from regulated activities? If not, explain. How is 'relatively pure-play' defined and what were the screening criteria used to select the U.S. utility sample?

Response:

The utilities selected were required to have regulated assets equal to or greater than 80% of total assets. As noted in response to BCUC IR 1.51.2, on a median basis, the sample had 93% of assets devoted to regulation, and the preponderance of the rest directly related to the regulated assets. All of the selection criteria are set out in Appendix B, page B-1 of Ms. McShane's testimony.

54.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 73-74

Regulatory Model: Canada and U.S.

Ms. McShane on pages 73 and 74 states "U.S. regulated companies represent a reasonable point of departure for the selection of a sample of proxies from which to estimate the cost of equity for an average risk Canadian utility. The operating (or business) environments are similar, the regulatory model in the U.S. is similar to the Canadian model, Canadian and U.S. capital markets are significantly integrated and the cost of capital environment is similar."77 [Emphasis added]

Ms. McShane cites in footnote 77 the Ontario Energy Board's Report of the Board on the Cost of Capital, pages 21-22.

In the 2009 Terasen Utilities Return on Equity and Capital Structure (Exhibit B-1), Ms. McShane mentioned Puget Energy on page 46 in a footnote 48, of Ms. McShane's testimony. Ms. McShane states

> "Pension funds are increasingly investing in infrastructure assets outside of Canada. For example, a consortium of investors including the British Columbia Investment Management Corporation, the Alberta Investment Management Corporation and the Canada Pension Plan Investment Board are in the process of acquiring Puget Energy, an electric and gas utility serving northern Washington state. The most recent allowed returns for Puget Sound Energy (both electric and gas) were 10.15% on a 46% common equity ratio, adopted in October 2008."

The Washington Utilities and Transportation Commission (WUTC) in Dockets UE-111048 and UG-111049 issued Order 08, Service Date May 7, 2012, in regard to rates for Puget Sound Energy, Inc. (Exhibit A2-16).

The WUTC in its decision determined on page 3 paragraph 7 "Among other significant findings and conclusions, we determine that PSE's capital structure should be revised to include a 48 percent equity ratio, balanced with a 48 percent long-term debt ratio and 4 percent short-term debt. This reflects most closely what we anticipate to be the Company's anticipated actual capital structure during the upcoming rate year. In terms of capital costs, we reduce PSE's authorized rate of return on equity from 10.1 percent to 9.80 percent."

The WUTC in its decision on pages 177 to 187 describes the issue of "attrition" and "regulatory lag" with possible causes with regards to Puget Sound Energy Inc. under-earning its authorized equity returns. The WUTC further discussed in detail possible regulatory changes that could address "attrition."

Bloomberg published a Business Wire, New York, news release dated August 20, 2009 titled "Fitch Affirms National Fuel Gas' IDR at 'A-'; Outlook Stable." http://www.bloomberg.com/apps/news?pid=newsarchive&sid=ajr.xqB2KKsI

Fitch Ratings affirmed National Fuel Gas Company's (NFG) Issuer Default Ratings (IDRs) and stated

> "The natural gas distribution utility operations provide a stable base to the company's overall business. About two-thirds of the utility's roughly 727,000 customers are in New York, with the remaining one-third in Pennsylvania. Although the New York Public Service Commission authorizes a fairly low return on equity (ROE) at 9.1%, it allows for <u>several constructive rate mechanisms, such as revenue decoupling, weather normalization, and rate trackers for gas costs, post-retirement medical expense, and pension expense. These mechanisms are viewed favorably</u> by Fitch because they tend to smooth out financial performance throughout the economic cycle and periods of commodity price and weather volatility. The Pennsylvania Public Utility Commission authorizes a higher ROE of between 10 and 11%, <u>but limits its rate mechanisms to trackers for gas costs and post-retirement medical expense</u>." [emphasis added] (Exhibit A2-17)

54.1 In Ms. McShane's view please describe "attrition" and "regulatory lag."

<u>Response:</u>

Regulatory lag refers to the time between the incurrence of costs and the time when the utility is able to recover those costs. The concept of regulatory lag includes the time that transpires between a utility's request for regulatory authorization for rates or to provide services and the granting of regulatory authorization. It can include the amount of time that transpires between rate proceedings.

Attrition refers to a persistent inability to earn the authorized return because revenues do not increase sufficiently to offset increases in costs.

54.2 In Ms. McShane's opinion please comment further on your statement "the regulatory model in the U.S. is similar to the Canadian model" while addressing the similarities and differences between the two countries with regards to preferred regulatory practices in:

- Choice of test year (historic vs future/forecast)

- Constructive rate mechanisms
- Revenue decoupling
- Weather normalization
- Rate trackers for gas costs, post-retirement medical expenses, pension expense
- Frequency of revenue requirement applications
- Frequency of return on equity and capital structure applications
- Conservation savings adjustment; Demand-side management decoupling
- Plant accounts (year-end, average, beginning, other)
- Inclusion of Construction Work in Progress (CWIP) in rate base
- Expense adjustments
- Equity share (thickness) upward adjustment for attrition
- Interim rates
- Use of deferral accounts
- Other relevant regulatory methods or practices

Please provide a response that includes a table similar to the one below.

Regulatory Method	Typical Canadian Practice	Typical U.S. Practice	Impact on Attrition, Regulatory Lag, and Business Risk
Choice of Test Year			
…			
…			

Response:

With respect to the similarity of the regulatory model, at a high level, utilities in both countries are governed by the fair return standard and the three requirements of comparable returns, financial integrity and capital attraction that the standard entails. In both countries, historical cost is the standard measurement of utility assets and revenue requirements are defined similarly. With respect to specific implementation of the regulatory model, although there are differences from jurisdiction to jurisdiction, the approach among Canadian jurisdictions is more homogenous than in the U.S. Among the U.S. regulatory jurisdictions, there is significantly more variation in approach, i.e., no single U.S. approach to the various methodologies and mechanisms listed in the question. As a result, there is not a single "U.S. practice" on each of the items listed in the question. This conclusion is borne out by the fact that S&P's evaluation of regulatory jurisdictions does not consider U.S. regulation as all the same, but rather rates each jurisdiction separately by its assessment of the degree of support of credit quality provided by the totality of the regulatory support in each jurisdiction. In its most recent evaluation of U.S. regulatory jurisdictions, it designated 28 of the 46 state regulatory jurisdictions it ranked as "more credit supportive" or "credit supportive" and 18 as "less credit supportive" or "least credit supportive." However, in broad terms, the U.S. regulatory environment is characterized by wide-spread use of regulatory mechanisms that are viewed as credit supportive. Most importantly, these regulatory mechanisms include accounts that provide for recovery of gas costs for gas utilities and fuel and purchased power costs for electric utilities, revenue decoupling, weather normalization accounts, trackers for new infrastructure investment (gas utilities), mechanisms for the recovery of bad debt expense and the ability to include CWIP in rate base.

Attachment 54.2 summarizes the use of the various methodologies and mechanisms listed in the question in the two countries to the extent feasible, given the range of practices, the impact on regulatory lag, attrition, where applicable, and/or variability in year-to-year earnings. Regulatory methodologies that reduce regulatory lag generally act to reduce business risk, other things being equal. Methodologies and mechanisms that act to prevent attrition, by definition, reduce business risk.

In the assessment of the regulatory risk for any particular company, it is necessary to look at the entire package of practices and mechanisms. For example, there are utilities in the U.S., including ones in Ms. McShane's sample, that operate with historic test years, but also with rate stabilization mechanisms that automatically adjust rates when required to allow the utility to earn its allowed ROE. With the operation of this type of rate stabilization mechanism, the type of test year that is used within the jurisdiction becomes effectively moot. Further, as regards the specific companies in Ms. McShane's U.S. utility sample, all of them operate in more than one regulatory jurisdiction, which diversifies their regulatory risk.

Ms. McShane discusses the methodologies and mechanisms included in Attachment 54.2 in the response to BCUC IR 1.54.2.1. Ms. McShane's overall conclusions regarding the comparability of U.S. and Canadian utilities are set out in the response to BCUC IR 1.54.3.

54.2.1 Please elaborate on why a regulator would choose one method over another. Discuss the advantages and disadvantages of each method with regards to intended outcomes such as risk reduction or efficiency incentive.

Response:

The following addresses the major categories of methodologies and mechanisms that were included in Attachment 54.2 filed in response to BCUC IR 1.54.2. In that context, Ms. McShane does not consider frequency of rate applications as a methodology, as in many instances, the frequency of rate applications is at the option of the utility, not chosen by the regulator. Similarly, as regards the frequency of cost of capital applications, unless there is a formula in place, which for many years was typical in Canada, cost of capital applications typically coincide with rate applications. Where there have been formulas, the decisions of regulators to do so have been largely based on efficiency and cost considerations.

Test Year:

A regulator may choose a historical test year adjusted for known and measurable changes, because it is based on readily verifiable data. Forecast test year data typically entails more scrutiny by regulators and intervenors. In periods of increasing unit costs, forward test years are more likely to be favoured, as they are likely to better match revenues and costs, and improve the utility's ability to earn its allowed return. For utilities with flat to declining unit costs, regulators may not view the benefits of a forecast test year as offsetting the costs of examining the utility's forecasts. A regulator may prefer a historical test year as an incentive mechanism to encourage cost efficiencies or consider that it has other tools at its disposal to provide a reasonable degree of assurance that the utility will earn a fair return. Even in jurisdictions where forecast test years are used, smaller utilities may opt to use historic test years as they do not have the resources to develop forecast test years.

Revenue Decoupling and Related Mechanisms:

Regulators are likely to opt for revenue decoupling because it is consistent with public policy objectives. Utilities would normally be incented to increase gas or electric sales, as that would be consistent with the profit maximization motive. Revenue decoupling is a means to attain public policy objectives (promote energy efficiency, reduce consumption of scarce resources) by removing the penalty for utilities to promote energy efficiency. Risk mitigation is a by-product of revenue decoupling but not its primary objective. Flat monthly fees have in some cases been chosen over revenue decoupling mechanisms, because they are viewed as achieving similar goals, but requiring less frequent rate adjustments.

Weather Normalization:

Weather normalization clauses, which are widely used among gas utilities, recognize that utilities' costs are largely fixed, but weather variations, which are beyond the control of the utility, can cause wide year-to-year swings in revenues. Weather normalization more closely aligns cost recovery with the manner in which costs are incurred. Weather normalization may not be implemented because of a perception that year-to-year volatility is expected to even out, and the benefits of earnings smoothing may not be viewed as sufficient to alter the manner in which customers are billed.

Rate Stabilization Mechanisms:

Rate stabilization mechanisms, which are used in some jurisdictions in the US, but not in Canada (FEI's RSAM is a decoupling mechanism, not a rate stabilization mechanism, despite its name) refer to mechanisms that reset rates (up or down) so as to bring the utility's return into the allowed range. The benefits are fewer rate cases, i.e., lesser regulatory burden, and an improved ability of the utility to earn the allowed return, which mitigates business risk. The main drawback is the potentially lower incentive for the utility to control costs.

Tracking Mechanisms:

With respect to tracking mechanisms or variance accounts, generally regulators would consider the following issues and make a determination as to whether the pros outweighed the cons.

1. Does it relate to costs that are outside the utility's control, are material, and unpredictable?
2. Should the risk of cost recovery lie largely with the utility or the ratepayer?
3. Would the mechanism unduly suppress the incentive to create cost efficiencies?
4. Would the mechanism potentially create perverse incentives, e.g., cause the utility to incur costs in the area covered by the mechanism, where it would be more appropriate to expend funds where a mechanism is not in place?
5. Does the mechanism relate to an expenditure which might not be justifiable on purely economic grounds, but is warranted due to public policy goals (e.g., environmental compliance expenses)?
7. Does the timely reflection of costs in rates help customers to make more informed consumption decisions?
8. Would the mechanism be supportive of credit quality?
9. Would the mechanism reduce the number of general rate applications?
10. Would the operation of the mechanism, by carving out one or more cost categories from the total revenue requirement, lessen the regulator's ability to assess the utility's overall costs?

These considerations would apply to all potential trackers or variance accounts, including those specifically identified below.

Trackers for Gas Costs and Fuel/Power Costs

These costs are largely outside the control of management, being subject to market forces, and make up a significant proportion of all gas utilities' and many electric utilities' costs. The use of trackers for these items, which is virtually universal for gas utilities and widely used for electric utilities, serves the dual purpose of reducing risk and sending correct pricing signals to customers. Regulators may implement some limitations on automatic cost recovery to the extent they view these costs as being partially under management control, to act as an incentive for the utility to minimize costs.

Trackers for New Infrastructure

Implemented for gas utilities, the tracker is intended to provide an incentive to undertake the investment required to replace aging plant on a timely basis, without requiring serial revenue requirement proceedings. Regulators may opt not to utilize a tracker if they perceive that it would unduly shift risks to ratepayers or prevent the regulator from evaluating the utility's costs in their totality.

CWIP in Rate Base:

Key considerations are whether the benefits of inclusion in rate base, i.e., acting as an incentive to undertake needed or required investment and providing cash flows throughout the construction process (credit support) offset potential inter-generational issues, i.e., recovery of costs from current customers before the plant is used and useful.

Income Tax Methodology:

In the U.S., the normalized/future tax methodology is generally required to comply with the tax code. In Canada, the taxes payable method has been favoured in recent decades as regulators have generally concluded that financial integrity will not be impaired and inter-generational equity will be served if current customers are only responsible for taxes that are actually payable during the test period.

54.3 In Ms. McShane's opinion does the Canadian regulatory framework including its regulatory practices result in lower, higher or same business risk for a Canadian utility relative to a U.S. utility, all else being equal? Please elaborate.

Response:

In the aggregate, i.e., taking account of all of the regulatory jurisdictions in Canada and the U.S., Ms. McShane considers that regulatory risk on average is somewhat higher in the U.S. than in Canada, due to the fact that there are still a number of U.S. jurisdictions where the availability of credit supportive mechanisms is more limited. Nevertheless, it is important to recognize that, even for those utilities that operate in jurisdictions with a less supportive regulatory framework, as long as their level of total risk (regulatory, fundamental business and financial risks), is comparable to FEI's total risk, those utilities are appropriate proxies for estimating FEI's cost of equity.

54.4 In Ms. McShane's opinion where does British Columbia rank among Canadian regulatory jurisdictions with regards to the use of "constructive rate mechanisms" (wording as used by Fitch Ratings) and its impact on credit metrics and business risk. Please elaborate.

Response:

Ms. McShane considers BC to be one of the more supportive regulatory jurisdictions in North America in terms of constructive regulatory mechanisms, considering the use of a forward test year and the availability of deferral accounts that mitigate short-term forecasting risk, resulting in relatively stable year-to-year earnings. The regulatory model in BC has had a positive impact on short-term business risk, as it reduces annual earnings volatility. Relative stability of earnings translates into relative stability of credit metrics. Despite the relative stability of credit metrics, the levels of the credit metrics are relatively low due to the levels of ROE and common equity ratios allowed. As noted at page 55 of her evidence, "With the requirement that the Commission consider applications in the context of the province's energy policies, in particular the 2010 Clean Energy Act, the regulatory environment has become more complex and less predictable."

55.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 39; 2009 ROE Decision, p. 77

Capital Structure for FEI as Benchmark BC Utility

On page 39 of Ms. McShane's testimony, Ms. McShane states that "This should not be interpreted to mean that business risks are only reflected in capital structure. Nor should it be interpreted to mean that the long-term aspects of business risk are captured only in capital structure with short-term variability in earnings captured solely in the ROE. Both the capital structure that is appropriate for a particular utility and the required rate of return on equity incorporate elements of short-term and long-term business risks. Investors look at the risks of a utility in the aggregate in assessing what return they require from a utility equity investment; they do not assign short-term risks to ROE and long-term risks to capital structure."

On page 77 of the 2009 ROE Decision, the Commission stated that "in determining TGI [now FEI]'s equity ratio and ROE in this proceeding it has sought to determine an equity ratio for TGI [now FEI] that reflects its long-term business risks, while adjusting its ROE to reflect its short-term business risks."

55.1 Please explain the shortcomings of assigning short-term risks to ROE and long-term risks to capital structure.

Response:

Ms. McShane is not aware of any methodology that would allow an accurate assignment of short-term risks to ROE and long-term risks to capital structure. However, she would note that attempting to do so may end up double adjusting for risks. In the 2009 ROE decision, at page 51, the Commission panel stated:

"The Commission Panel agrees with Dr Booth that "significant risk adjustments" to US utility data are required in this instance to recognize the fact that TGI possesses a full array of deferral mechanisms which give it more certainty that it will, in the short- term, earn its allowed return than the Value Line US natural gas LDCs enjoy. The Commission Panel notes Dr. Booth's suggestion that the risk premium required by US utilities is between 90 and 100 basis points more than utilities in Canada require may set an upper limit on the necessary adjustment. Accordingly, the Commission Panel will reduce its DCF estimate by between 50 and 100 basis points to a range of 9.0 percent to 10.0 percent, before any allowance for financing flexibility."

Ms. McShane sees no evidence in the decision that the Commission had concluded that the long-term risks of FEI and the U.S. utilities were different. However, the common equity ratios of the U.S. utility samples were materially higher than the 40% equity ratio that the Commission had determined for FEI. Effectively the Commission adjusted twice for relative risk, once by setting FEI's common equity ratio at 40% compared to the 47% common equity ratios of Ms. McShane's U.S. utility sample, and again by adjusting down the proxy samples' cost of equity for what the Commission viewed to be lower short-term risks for FEI.

55.2 If the 2009 Decision would have been consistent with Ms. McShane's testimony, please explain what impacts this would have had on the appropriate 2009 capital structure and ROE. For example, would the appropriate capital structure be 38 percent instead of 40 percent?

Response:

The capital structure would have stayed the same, as proposed, but no downward adjustments would have been made to the cost of equity tests applied to U.S. utilities. To the extent the short-term risks of the proxy U.S. utilities were lower than those of FEI, they had already been captured in a thicker common equity ratio.

56.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 78 & 92

CAPM

On page 78 of Ms. McShane's testimony, Ms. McShane states that

> "The risk-adjusted equity market risk premium approach to estimating the required equity market risk premium for a utility entails (1) estimating the equity risk premium for the equity market as a whole; (2) estimating the relative risk adjustment; and (3) applying the relative risk adjustment to the equity market risk premium, to arrive at the required utility equity market risk premium. The cost of equity is thus estimated as:
>
> Risk-Free Rate + { Relative Risk Adjustment x Market Risk Premium }
>
> The risk-adjusted equity market risk premium test is a variant of the Capital Asset Pricing Model (CAPM). The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor should require (in contrast to what the investor does require). Its focus is on the minimum return that will allow a company to attract equity capital."

and at page 67 Ms McShane acknowledges that:

> "2. The size of the market risk premium cannot be directly observed and is subject to a wide divergence of opinion. While historic risk premiums may provide a perspective on the size of the expected forward-looking market risk premium, historic results are sensitive to the country from which the data are drawn and the time period over which they are measured.
>
> 3. The market risk premium is not a fixed quantity; it changes with investor experience and expectations. It would be higher, for example, when investors perceive that the risk of the equity market has increased relative to that of the government bond market and vice versa. However, the model does not readily allow estimation of changes in the size of the market risk premium as economic or capital market conditions (e.g., interest rates) change."

And at page 92, Ms McShane restates the equity risk premium "In the context of the CAPM, the utility return should equal:

Risk-Free Rate + Beta X (Equity Market Return – Risk-Free Rate)

56.1 Ms. McShane chose to use a 3-year projection of the LCB risk free rate at 4 percent. What impact on her projections would occur if she used her current year projection of 2.6 percent? Since we are setting ROEs for 2013, wouldn't the

2.6 percent rate be more applicable. Please show the impact on Ms. McShane's CAPM if the risk free rate were forecast to be 2.6 percent.

Response:

Ms. McShane's projected long-term Canada bond yield of 2.6% was for 2012, not 2013, as stated at page 77, lines 1986-1987. The projected long-term Canada bond yield for 2013 only was 3.2%, as indicated in footnote 84 on page 77 of Ms. McShane's evidence. Ms. McShane explained at page 33, lines 828-833 and page 34, lines 835-838 the basis for using a forecast long-term Government of Canada bond yield of 4.0%. If the Commission were to set the benchmark utility ROE for 2013 only, to be followed by a subsequent proceeding to set the benchmark utility ROE for 2014, then it would appropriate to rely on the 2013 forecast to estimate the cost of equity using the CAPM. If the 2013 3.2% long-term Canada bond yield were used in the CAPM, rather than the 2013-2015 forecast were used, the market equity risk premium would also need to be re-estimated. Based on Ms. McShane's analysis at pages 86 to 87, at a long-term Canada bond yield forecast of 3.2%, the corresponding equity market risk premium would be no less than 8.0%, and the resulting CAPM cost of equity would be 8.6%, before any adjustment for financing flexibility.

56.2 With respect to Beta there she provides much discussion of fluctuations in Raw Betas of Canadian utilities over time and the efforts to manipulate the Raw Betas by assuming some trend towards 1.0 to produce Adjusted Betas which are higher. Could it be that Canadian utilities enjoy so many risk item deferral accounts and positive incentives that their risk profiles are indeed closer to the Raw Betas? Please show the impact on Ms. McShane's CAPM if Raw Betas were used.

Response:

Ms. McShane disagrees with the premise of the preamble, specifically the reference to "the efforts to manipulate the Raw Betas by assuming some trend towards 1.0 to produce Adjusted Betas which are higher." Ms. McShane explained at lines 2429 to 2451, the rationale for adjusting utility betas, which is not based on a trend toward 1.0. As Ms. McShane noted in that passage of her testimony, the purpose of the CAPM is to predict returns and adjusted betas are better predictors than "raw" betas. Ms. McShane does not accept that the low "raw" betas reflect the existence of deferral accounts or positive incentives. In Ms. McShane's view, the "raw" betas are virtually meaningless, inasmuch as, as indicated on Schedule 14, page 2 of 6, they have virtually no explanatory power.

If Ms. McShane had used the recent "raw" monthly betas of the individual Canadian utilities of approximately 0.20 to 0.25 in conjunction with the 3.2% forecast 2013 long-term Canada bond yield and an equity market risk premium of 8.0%, the indicated cost of equity is approximately 5.0%, a clearly unreasonable result.

56.3 The overall market equity return projections rely on a great deal of historical data. However, one reads articles that pension funds and large investors have reduced their long term expectations of market returns due to continuing financial crises, prolonged recessions and reliance on low interest rates to support any growth. Could it be that the extent of financial turmoil since 2008 has reduced investors' expectations for future returns? What would be the impact on Ms. McShane's CAPM if the forward equity market risk premium were estimated to be 5-6 percent over a current risk free rate of 2.6 percent (i.e., an equity market return of about 7.5 percent to 8.5 percent)?

Response:

It is possible that investors' recent experience in the equity markets (e.g. annual compound rate of return, including dividends, on the S&P/TSX for the five years ending August 2012 of 0.2%) has coloured their outlook. This phenomenon is not unusual. In the late 1990s, during the technology sector bubble, investor expectations for future returns reflected the market exuberance at the time.

Ms. McShane is providing the requested calculation based on her 2013 forecast 3.2% long-term Canada bond yield. She notes, however, that there is a disconnect if one utilizes a long-run average market risk premium of 5.0% to 6.0%, which should represent the difference between the long-run equity and the long-run government bond return, and a current or near-term forecast of 30-year Government of Canada bond yields. At a long-term Canada bond yield of 3.2%, Ms. McShane's relative risk adjustment of 0.65-0.70, and a market risk premium of 5.5%, equal to the mid-point of the range specified in the question, the indicated return is 6.9%, which is clearly unreasonable.

If the CAPM had been performed using all the assumptions that the question has asked Ms. McShane to accept, i.e., a 2.6% long-term Canada bond yield, raw betas, which have recently been in the range of 0.20 to 0.25 measured using monthly price changes, and a market risk premium with a mid-point of 5.5%, the indicated CAPM cost of equity would be 3.84%, or approximately equal to the current yield on long-term A rated utility bonds. This is a patently unreasonable result.

56.4 With all these assumptions to construct a CAPM, what confidence level does Ms.McShane have in her results?

Response:

Ms. McShane acknowledges that the application of the CAPM, at any time, requires significant judgment, as should be clear from her detailed discussion of the challenges of the test at lines 1705 to 1762 of her testimony. Its application is particularly problematic under current market conditions, even more so than it was at the time of the 2009 ROE proceeding. As a result, she has less confidence in the test than she would if markets were more normal, and underscores the conclusions drawn at page 70, regarding the need to consider and give weight to multiple tests to ensure that the fair return standard is adhered to.

57.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 109-113

DCF Model

Ms. McShane states that "The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows."

and: "The DCF test allows the analyst to directly estimate the utility cost of equity, in contrast to the Capital Asset Pricing Model (CAPM), which estimates the cost of equity indirectly."

57.1 Since FEI is not traded publicly, the DCF test cannot "directly" estimate its cost of equity, can it?

Response:

The DCF test cannot be directly applied to FEI, as FEI is not a publicly-traded company (see page 111, lines 2802 to 2803). However, the referenced statement at page 109 that "the DCF test allows the analyst to directly estimate the utility cost of equity, **in contrast to the Capital Asset Pricing Model (CAPM)**, which estimates the cost of equity indirectly" [emphasis added] should be viewed in the context of the earlier discussion in Section VIII.A, Importance of Multiple Tests (pages 65-70). Specifically, as discussed in the earlier section, unlike the CAPM model which relies on three variables, only one of which is directly related to utility-specific market data, i.e., the relative risk adjustment, the DCF model relies on inputs that are all based on utility-specific data (prices, dividends and forecast growth). The term "utility-specific" is not intended to convey that the DCF test is applied to the subject company, but rather to utilities. The application of any cost of equity estimate that relies on data for only a single company is subject to measurement error. In addition, the application of the DCF test to the subject company entails a considerable degree of circularity. Further, applying the DCF test only to the subject company would be incompatible with the fair return standard, which requires that the return be commensurate with those of comparable risk enterprises. Therefore, for purposes of the DCF test, Ms. McShane utilized samples of utilities, and would have done so even if FEI were publicly-traded.

57.2 The FBCU's business risk evidence generally argues that the future throughput of FEI is either stagnant or challenged. As a result one might speculate that rate base growth may be minimal as capital maintenance additions are offset by depreciation. With little or no growth, the growth in dividends might be minimal.

What is the impact on Ms. McShane's forecast cost of equity (k) if dividend growth (g) is set to zero?

Response:

None, as discussed in response to BCUC IR 1.57.1. Conceptually, if expected growth for a sample of utilities is zero in perpetuity, the estimated DCF cost of equity would equal the current period dividend yield. However, with zero growth, the market yield would be higher than the yields for the proxy samples of utilities, which are expected to experience long-term growth.

57.3 How sensitive are Ms. McShane's results to variations in discount rate? If the real discount rate were increased or decreased by 2 percent, what impact would result?

Response:

Ms. McShane is not certain what is being asked. A "discount rate" is what the DCF test measures. In principle, if the discount rate has changed by 2%, the DCF test results would change by 2%.

57.4 Are the DCF results vulnerable to fluctuation as markets increase or decrease the P/E ratios of utilities vs the TSX? For example, if utilities have unusually high P/E ratios at a point in time would it be appropriate to speculate that utility stock prices will fall compared to the TSX as market conditions stabilize? How would this be accounted for in the DCF model?

Response:

Yes, the DCF test results will vary based on changes in utility market prices and expected long-term growth rates, just as the CAPM results will vary based on changes in forecast long-term Canada bond yields and expected equity market returns. The DCF test is based on the efficient markets hypothesis, the premise of which is that prevailing share prices always incorporate all available information. However, it is recognized that share prices on any given day may incorporate transitory information. Consequently, the application of the DCF test typically does not utilize "spot" prices, but prices averaged over a longer period. There is a strong likelihood that utility share prices will fall, which all other things equal (i.e., expected growth), would cause the DCF cost of equity estimates to rise. Utility share prices are sensitive to changes in interest rates, and interest rates are expected to rise. Further, as noted in response to BCUC IR 1.35.1.2, based on high earnings multiples relative to history in conjunction with their fundamental earnings prospects, there is some concern in the market that utility stocks are overvalued. A correction in utility share prices would also, all other things equal, result in an increase in the DCF cost of equity estimates. Nevertheless, Ms. McShane has no objective basis on which to adjust the utility prices and dividend yields for that eventuality.

57.5 With all these judgment factors what range of FEI's cost of equity would Ms. McShane view as reasonable?

Response:

Ms. McShane's recommended ROE for the benchmark utility is not based solely on the DCF test, as she recognized that none of the individual tests is, on its own, a sufficient means of ensuring that all three requirements of the fair return standard are met and that each of the tests has its own strengths and weaknesses. Please see discussion at lines 1685 to 1703 of Ms. McShane's testimony. Given the inherent imprecision in any cost of equity estimate, Ms. McShane considers that the fair ROE for the benchmark BC utility falls within a range of +/- 25 basis points of the recommended ROE of 10.5%.

58.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 113

DCF Model

Ms. McShane states that "For the Canadian utilities, the higher long-term earnings growth forecasts in conjunction with lower dividend yields lead to a wider range of DCF test results than for the U.S. utilities. Based on the mid-point of the range of the constant growth and three-stage models, the cost of equity for the Canadian utility sample is approximately 9.8%."

58.1 Please provide the range of results for the Canadian utilities?

Response:

The DCF test results for the Canadian utilities are shown on Schedules 22 (Constant Growth) and Schedule 23 (Three-Stage Growth). The range of results is 10.8% to 11.2% on Schedule 22 and 8.6% to 8.7% on Schedule 23, for a mid-point of 9.8%.

59.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 115-117

Fair ROE for FEI as Benchmark BC Utility

On page 115, Ms. McShane states that among the principal issues in the application of the comparable earnings test are: (1) the selection of a sample of unregulated companies of reasonably comparable total risk to a Canadian utility and (3) the need for any adjustment to the "raw" comparable earnings results if the selected unregulated companies are not of precisely equivalent risk to a utility. She adds that the selection should conform to investor perceptions of the risk characteristics of utilities, which are generally characterized by relative stability of earnings, dividends and market prices.

Then, Ms. McShane lists the criteria she used to select comparable unregulated low risk companies and later indicates that the experienced returns on equity of the sample of 21 Canadian low-risk unregulated companies over this period were in the range of 12.25%-13.5%. Further, she states that the comparative risk data indicate that the unregulated Canadian companies are of higher risk than the benchmark BC utility, FEI, which warrants a downward adjustment of 125 to 150 basis points to their returns on equity. As a result, a fair return on equity based on the comparable earnings test is approximately 11.0% to 12.0%.

In Appendix E to her testimony (page E-1), Ms. McShane states "The selection process starts with the recognition that unregulated companies generally are exposed to higher business risk, but lower financial risk, than the typical utility. The selection of unregulated companies focuses on total investment risk, i.e., the combined business and financial risks. The unregulated companies' higher business risks are offset by a more conservative capital structure, i.e., higher equity ratios, thus permitting the selection of samples of reasonable comparable investment risk to utilities."

59.1 If, under the comparable earnings test, the most representative sample of unregulated companies of comparable total risk consisted of 21 <u>low-risk</u> unregulated companies, which were then <u>considered of higher risk than the benchmark BC utility</u>, does it not automatically follow that the benchmark BC utility is also low-risk, at the minimum? If not, please explain why not.

<u>Response:</u>

No. The context is different. The characterization of FEI as low risk was, as Ms. McShane understands it, in relation to other Canadian and BC utilities. The selection of low risk unregulated companies is by reference to the full universe of unregulated companies.

59.2 Why would criteria to define a 'low-risk' company differ between the consumer-oriented industries from which the sample of 21 companies was drawn from and the utility industry?

Response:

With respect to the relevance of the utility selection criteria to the selection of the unregulated companies:

- Since the unregulated companies are not utilities, designation as a utility is not relevant. Similarly, the percentage of utility assets criterion used to select the U.S. utilities is not relevant to unregulated companies.
- The *Value Line* ranking criterion used to select the U.S. utilities is not relevant to Canadian unregulated companies as most of the unregulated companies in Canada are not followed by *Value Line*.
- The business risk score of "Excellent' by S&P is not a relevant criterion for the unregulated companies, for two reasons. First, the use of unregulated companies recognizes that the business risk is higher, offset by lower financial risk. Second many of the unregulated companies are not rated by S&P, at least in part because they carry little debt.
- Whether or not the unregulated companies are involved in a pending merger or acquisition is not relevant, because the unregulated companies' book returns are being measured, which are not affected by merger or acquisition activity. In contrast, the tests applied to the utility sample rely on market prices, which may be unduly affected by merger or acquisition activity.
- The availability of growth forecasts was not relevant to the unregulated companies, as the discounted cash flow test, which relies on those forecasts, was not applied to the unregulated companies.
- As regards the selection of the unregulated companies, given the nature of the test for which the companies were used, the criteria had to include data available over a long enough period and that produced meaningful ROE values. Further, certain selection criteria for the unregulated companies are effectively chosen once the characteristics of the utilities are known, e.g., betas.

60.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 78 and 89

Risk Adjusted Equity Market Risk Premium

On page 89, Ms. McShane states that "Utilities are not investing in a portfolio of securities. They are committing capital to long-term assets. Once the capital is committed, it cannot be withdrawn and redeployed elsewhere. The CAPM does not capture that reality."

On page 78, Ms. Mcshane's evidence says that: "The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor should require…."

60.1 As Ms. McShane's evidence states it is not utilities investing in a portfolio of securities, but equity investors who are looking at a diversified portfolio. Then does it matter from an investor's perspective if the utility is committing capital to long-term assets? If so, why?

Response:

Yes, it does matter that the utility is committing capital to long-term assets. As Ms. McShane stated at lines 2266 – 2267, "Once the capital is committed, it cannot be withdrawn and redeployed elsewhere." The Capital Asset Pricing Model focuses on the contribution of a particular security to a portfolio's risk, where risk is measured as how the price of that security fluctuates with changes in the overall market. It does not focus on the fundamental risks related to the underlying real assets, and the risk that capital invested in real assets will not earn returns that could have been achieved by investing in comparable risk real assets and the risk that the capital invested in real assets will not be recovered.

61.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 79 and 83

Risk Adjusted Equity Market Risk Premium

On page 83, Ms. McShane states that "The 2013-2015 forecast long-term Government of Canada bond yield of 4.0% suggests an equity risk premium, based on historical risk premiums at similar levels of interest rates, of approximately 7.25% to 7.5%."

On page 79, Ms. McShane states that "Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to reflect as broad a range of event types as possible to avoid overweighting periods that represent "unusual" circumstances."

61.1 Doesn't Ms. McShane's estimate of the equity risk premium based on historical risk premiums at similar levels of interest, as opposed to all interest levels over a long period of time, violate the principle Ms. McShane articulates at page 79? If not, why not?

Response:

The references are not contradictory. The estimation of the expected market risk premium from achieved market risk premiums is premised on the notion that investors' expectations are linked to their past experience. As expressed at page 79, by basing the calculations of achieved risk premiums on the longest periods available it is possible to reflect as broad a range of event types yet avoid overweighting periods that represent 'unusual' circumstances. On the other hand, the objective of the analysis is to assess investor expectations for a particular period, whether it be the current economic and capital market environment or, as it is in this case, as forecast for 2013-2015. Hence, as explained at page 83, focus should be placed on periods whose economic characteristics, on balance, are more closely aligned with what today's investors are likely to anticipate.

62.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 80; Appendix I Concentric Report p. 28

Arithmetic and Geometric Averages

On page 80, Ms. McShane displays the historical risk premiums for Canada and the U.S. using arithmetic averages (Footnote 89), and the standard deviation of returns on page 85 Table 14.

On page 28 of the Concentric report (Exhibit B1-9-6, Appendix I), the standard deviation of U.S. ROE decisions between 1994-2010 is reported as 0.53%

62.1 Please provide a table showing risk premiums over Bond Total Returns and over Bond Income Returns, using geometric averages.

Response:

The table below shows the risk premiums over Bond Total Returns and over Bond Income Returns using geometric averages. As discussed in Appendix A of Ms. McShane's testimony, the arithmetic average, not the geometric average, should be used to estimate the expected equity market risk premium.

		Bond Returns:		Risk Premium Over Bond:	
Period	**Stock Returns**	**Total Returns**	**Income Returns**	**Total Returns**	**Income Returns**
Canada					
1924-2011	9.8	6.3	6	3.5	3.8
1947-2011	10.4	6.7	6.7	3.8	3.7
U.S.					
1926-2011	9.8	5.7	5.1	4.1	4.7
1947-2011	10.9	6.1	5.9	4.8	5

62.2 Please comment on the difference between the standard deviation of returns of the equity markets in the US and Canada (as shown in Table 14) and the standard deviation of U.S. ROE decisions.

Response:

In Ms. McShane's opinion, the two standard deviations are entirely unrelated. The values in Ms. McShane's Table 14 measure the standard deviations of annual returns in the market, whereas the value in Mr. Coyne's report measures the standard deviations of returns that are, conceptually, long-run average expected returns. A more relevant comparison is the standard deviation of annual utility equity market returns to those of the overall equity market.

For the comparable periods shown in Ms. McShane's Table 27 (and associated Schedule 18), the standard deviations of the annual returns are as follows:

	Standard Deviation		
	S&P/TSX	**Canadian Utilities**	
1956 to 2011	16.80%	15.50%	
	S&P 500	**U.S. Gas Utilities**	**U.S. Electric Utilities**
1947 to 2011	17.40%	14.90%	16.70%

63.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 84

On page 84 of Ms. McShane's testimony, Ms. McShane displays inflation ranges and their associated returns on table 13.

63.1 Please provide the specific calendar years, inflation rates, nominal equity returns and real equity returns for each year in which inflation was less than 1 percent.

<u>Response:</u>

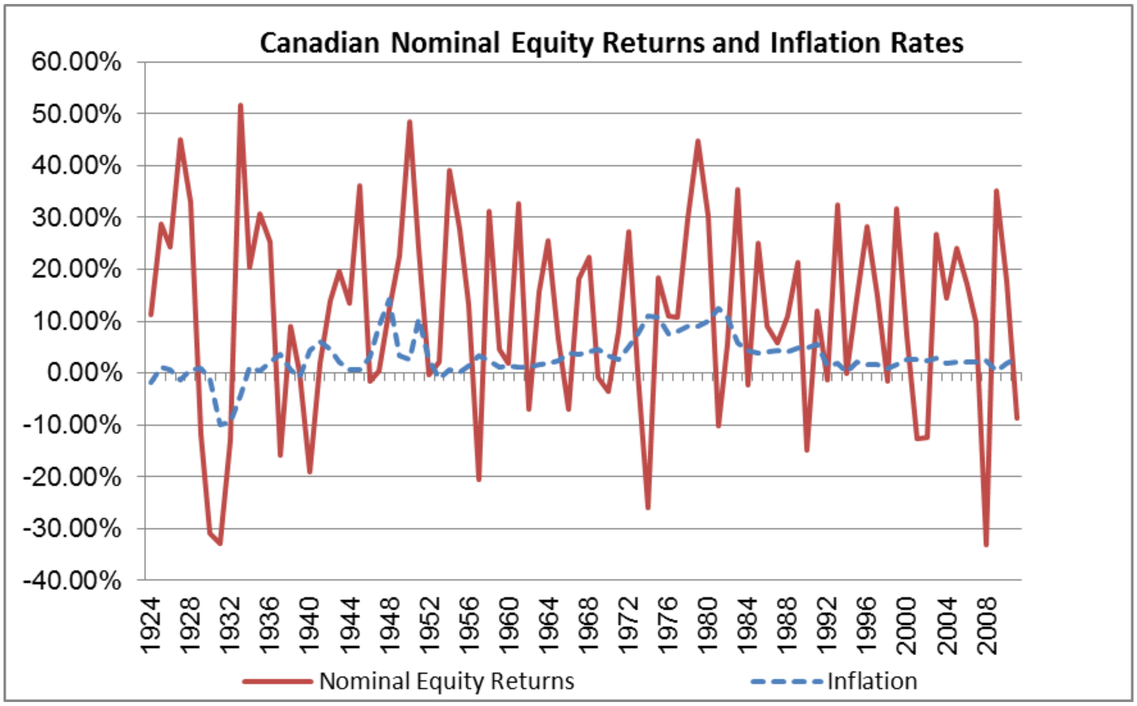
The table below shows the calendar year, inflation rate, nominal equity returns and real equity returns for each year in which inflation was less than 1 percent.

Year	Inflation Rate	Nominal Equity Return	Real Equity Return
1931	-9.85%	-32.96%	-23.11%
1932	-9.41%	-12.92%	-3.51%
1933	-4.36%	51.63%	55.99%
1924	-1.90%	11.25%	13.15%
1927	-1.45%	44.92%	46.37%
1953	-1.00%	2.15%	3.15%
1930	-0.99%	-30.90%	-29.91%
1939	-0.76%	0.19%	0.95%
1994	0.17%	-0.18%	-0.35%
1955	0.18%	27.80%	27.62%
2009	0.30%	35.05%	34.76%
1935	0.46%	30.63%	30.17%
1938	0.54%	9.13%	8.59%
1945	0.64%	36.05%	35.41%
1944	0.65%	13.47%	12.82%
1954	0.65%	39.05%	38.40%
1926	0.73%	24.42%	23.69%
1928	0.74%	32.92%	32.18%

63.2 Please provide a graph of inflation rates and nominal equity returns on a calendar year basis over the historical period of 1924-2011.

Response:

The graph below charts inflation rates and nominal equity returns over the period 1924-2011.



64.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 83-87

Risk Adjusted Equity Market Risk Premium

Ms. McShane's evidence on page 87 states "Given the absence of any material upward or downward trend in the nominal historic equity market returns over the longer-term, the P/E ratio analysis, and the observed negative relationship between real equity returns and inflation, a reasonable estimate of the expected value of the nominal equity market return is approximately 11.5%, based on Canadian equity market returns and supported by U.S. equity market returns."

In footnote 94 on page 83, Ms. McShane states "I analyzed the trends in P/E ratios and equity market returns and determined that there is no indication that rising P/E ratios during the bull market of the 1990s resulted in average equity market returns that are unsustainable going forward." The analysis is summarized in Appendix A.

64.1 Based on the comment in footnote 94 is it correct to conclude that no adjustment was made based on the P/E analysis? If there was an adjustment made please identify it.

Response:

Correct.

65.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 92

Risk Adjusted Equity Market Risk Premium

65.1 With respect to footnote 104 on page 92 please confirm that the earliest data available are for January 1970. If equivalent data exists prior to that date please redo the analysis using all available data.

Response:

Ms. McShane does not have data prior to 1970.

66.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 92-93

Risk Adjusted Equity Market Risk Premium

On pages 92-95, Ms. McShane discusses her one and two factor regression models.

66.1 Please indicate whether or not Ms. McShane tested for possible errors resulting from autocorrelation. If so, what was the resulting value of the Durbin –Watson statistic and what, in Ms. McShane's view does it indicate?

Response:

Ms. McShane did calculate the Durbin-Watson statistics for the regressions involving excess returns. The Durbin-Watson values were 1.94 and 1.96 for the regressions in Tables 17 and 18, respectively, indicating little or no collinearity in the regressions. Further, collinearity is often suspected when the R^2 of the regression is high (above 0.7), the correlation amongst the explanatory variables is above +/- 0.50, and the estimated coefficients are individually statistically insignificant. With relatively low R^2s, statistically significant coefficients and relatively low correlation in both regressions, collinearity was not considered to be a serious problem. It should be noted, however, that the presence of multicollinearity does not bias the estimated coefficients but rather renders inferences from the t-statistics problematic as it narrows standard errors.

66.2 Please confirm that multicollinearity exists whenever a high degree of intercorrelation exists among some or all of the explanatory variables in a regression equation. At page 103 she states that since utility shares are interest sensitive the regression was expanded to capture the impact of movements in long-term Canada bond prices on utility returns. Did Ms. McShane consider that the monthly TSE composite excess return over T-bills and the monthly excess Long Canada bond return over T-Bills might be intercorrelated. Did she test for that and if so what were the results.

Response:

It is confirmed that multicollinearity exists when there is linear relationship between the explanatory variables in data involving economic time series. Please refer to the response to BCUC IR 1.66.1 above.

66.3 Please confirm that specification and measurement errors can result when one or more significant explanatory variables are not included in the regression equation.

Response:

It is confirmed that specification and measurement errors can result when one or more significant explanatory variables are not included in the regression equation. To have an impact on the results, e.g. biasing the estimated coefficients, the excluded variable(s) must be both correlated with the other explanatory variables and, when included, be statistically significant. If a model is mis-specified the ordinary least squares estimators will be biased in the same direction, positive or negative, as the covariance between the included and excluded variables.

66.4 On page 93, Ms. McShane's evidence says that "The intercept in the equation should, in principle, represent the risk-free rate." To what extent will any or all of the potential errors identified above affect the value of the intercept? Moreover, would Ms. McShane agree that if the R2 is worse (i.e., explains less) the intercept arguably explains more, but the confidence in the value suggested by the intercept is less? If not, why not?

Response:

As stated in response to BCUC IR 1.66.1 above, multicollinearity was not considered to be a serious problem in either of the regressions presented in Tables 17 and 18. The correlation between the explanatory variables (Monthly Excess Long Canada Bond Return Over T-Bills and the Monthly TSE Composite Excess Return Over T-Bills) is low, at 0.23. Therefore, the expansion of the regression in Table 17 to include the Monthly Excess Long Canada Bond Return Over T-Bills does not indicate that the initial regression (Table 17) was mis-specified. As a result, with no indication of either multicollinearity or misspecification in the models the estimated coefficients can be used to provide one estimate of the indicated relative risk adjustment.

The R^2 of the regression in Table 17 is lower (28%), i.e., explains less, than the R^2 in Table 18 (37%), while the t-statistic on the intercept is higher (5.4 vs. 5.0). If the model in Table 17 were mis-specified, the confidence in the value of the estimated intercept would be lower due to possible bias. However, there is no indication that the model is mis-specified.

As a final point, the statement at page 93 that "The intercept in the equation should, in principle, represent the risk-free rate" reflects the formulation of the CAPM presented at line 2339 where the utility return should equal:

Risk-Free Rate + Beta X (Equity Market Return - Risk-Free Rate)

The results in Tables 17 and 18, indicating a component of utility return in excess of what the theoretical CAPM would predict are consistent with empirical studies of the CAPM discussed in Appendix A to Ms. McShane's testimony.

67.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 103

Risk Adjusted Equity Market Risk Premium

On pages 103-104, Ms. McShane's evidence analyses the relationship between the government bond yield and the utility equity risk premium, based on data from 1998 to 2012Q1.

67.1 Why was the time period 1998 – 2012Q1 chosen?

Response:

As noted in footnote 119, page 99, "The choice of period 1998-2012Q1 reflects the years during which long-term Canada and U. S. Treasury bond yields have been broadly similar. It is also intended to balance the exclusion of periods that are dissimilar to current relationships between equity costs and government bond yields and the inclusion of sufficient observations to construct a reliable analysis."

67.2 Did Ms. McShane consider basing her analysis using other time periods? If so, please provide the results and discuss why she thinks the results from the 1998-2012Q1 time period are superior.

Response:

Yes, other periods were considered, but the 1998-2012Q1 period was determined to be the most appropriate for the analysis for the reasons, set forth in response to BCUC IR 1.67.1. Ms. McShane did not conduct analysis using other periods, and thus does not have other results to provide.

68.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 102-104

Risk Adjusted Equity Market Risk Premium

On pages 102-104, Ms. McShane discusses her one and two factor regression models used to test the relationship between equity risk premiums and interest rates. On page 102, Ms. McShane states that

"…there is an inverse relationship between long-term government bond yields and the utility equity risk premium."

68.1 On page 103, Ms. McShane's evidence states that she regressed the quarterly allowed ROEs against lagged long-term Treasury bond yields. Did Ms. McShane test for possible errors resulting from autocorrelation? If so, what was the resulting value of the Durbin –Watson statistic and what, in Ms. McShane's view does it indicate?

Response:

Ms. McShane did calculate the Durbin-Watson statistic for the regression of the risk premium indicated by the quarterly allowed ROEs from 1998 to 2012Q1 against long-term Treasury bond yields lagged by six months. The value of the Durbin-Watson statistic was 1.44 (rho of 0.28). At this level, with only 56 observations and one explanatory variable (in addition to the intercept), there is little likelihood of collinearity in the regression. As serial correlation does not impact the estimated coefficients, but biases tests of significance, by narrowing the standard error and thereby increasing the t-statistics, nothing further was done.

68.2 To what extent is it possible or likely that multicollinearity exists when adding long-term A-rated utility/government bond yields as a second explanatory variable (in addition to long-term Treasury bond yields)? Did Ms. McShane test for multicollinearity and if so what were the results?

Response:

No specific test for multicollinearity was conducted, as the correlation between the two explanatory variables, the spread between A-rated utility and government bond yields and long-term government bond yields, was 0.05, indicating that multicollinearity was not a serious problem.

69.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 104, footnote 126

Risk Adjusted Equity Market Risk Premium

On page 104 of Ms. McShane's evidence, Ms. McShane states that "The regressions were solved using the forecast 4.0% 30-year Canada bond yield. For the 30-year A-rated utility/Government of Canada bond yield spread, a spread of 135 basis points was used."

Footnote 126 on page 104 explains Ms. McShane's choice of a 135 basis point yield spread.

> "Represents expectation that the spread between the yield on long-term A rated Canadian utility bonds and Government of Canada bonds will contract from recent levels (approximately 160 basis points at the end of June 2012) as measured by the spread between the yield on the Bloomberg A-rated Canadian Utility 30 Year Index and the benchmark long-term Government of Canada bond) as yields on long-term Government of Canada bonds rise."

69.1 What is the historical average spread between the yield on long-term A-rated Canadian utility bonds and Government of Canada bonds?

<u>Response:</u>

There is no consistent historical series of A-rated Canadian long-term utility bond yields. Based on the Bloomberg A-rated Canadian Utility 30 Year Index (first reported March 2002) and the benchmark long-term Government of Canada bond yield, as referenced in footnote 126 on page 104, the historical average spread was 129 basis points over the period March 2002 to June 2012. Through the end of August 2012 the spread remains at 129 basis points. From the beginning of 2011 to end of August 2012, the average has been 148 basis points.

Based on the CBRS 30-year A rated utility index yields that were maintained from October 1995 to September 2000, combined with the yields on a sample of long-term A-rated utility bonds tracked by Foster Associates Inc. (bond yields obtained from www.GlobeInvestorgold.com) from October 2000 to present, the historical average spread was 129 basis points over the period October 1995 to August 2012, compared to 157 basis points from the beginning of 2011 to August 2012.

70.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 107

Risk Adjusted Equity Market Risk Premium

On page 107, Ms. McShane states that "A 50% sensitivity factor comports with the lower end of the range of the sensitivities of utility equity risk premiums to government bond yield changes estimated in Section VIII.D.3.c above."

70.1 Can Ms. McShane clarify that the analysis she is referring to is at pages 101-104, in section VIII.D.4.d? If not please clarify or refine the reference.

Response:

It is confirmed. The testimony had an incorrect cross-reference.

71.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 111

Risk Adjusted Equity Market Risk Premium

On page 111, Ms. McShane says that "…as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns."

71.1 To what extent is there evidence that investors do believe the forecasts or, conversely, that investors adjust for overly optimistic forecasts?

Response:

The premise of the question appears to proceed on the assumption that the relevant analysts' forecasts are "overly optimistic", which Ms. McShane does not accept. While Ms. McShane acknowledged that, as stated on page 111 of Ms. McShane's testimony, "analysts' earnings growth forecasts as a measure of investor expectations [have] been questioned by some Canadian regulators, as some studies have concluded that analysts' earnings growth forecasts are optimistic", she tested this proposition with respect to the forecasts for her own sample, and found that that there was no support for this proposition. Indeed, the Commission, in the *2009 ROE Decision*, rejected the notion of analyst bias, stating:

> *The Commission Panel has considered the submission of the JIESC concerning "upward bias" of analysts' estimates and considers that no allegations of upward bias have been levelled against utility analysts and that Value Line estimates will be free from any suggestion of upward bias.* ***Accordingly the Commission Panel will not give any weight to suggestions of analyst bias.*** (page 45) [emphasis added]

In respect to whether, more broadly, investors believe the forecasts, the very fact that an extensive investment research industry has developed, and continues to thrive, signals that value is perceived in the forecasts. The extensive bibliography of academic articles on analysts' forecasts is premised on the belief that the forecasts are determinants of market behaviour. If analysts' forecasts were viewed to be of little import in explaining market behaviour, it is unlikely that the vast literature on those forecasts would exist. Despite the "credibility gap" focused on technology stocks in the early 2000s, brokerages continue to employ analysts, and consensus forecasts continue to be compared to actual company results when reported, with stock prices reacting positively when actuals exceed forecasts ("earnings surprises") and vice versa. To Ms. McShane's knowledge, there have been no recent studies that deal specifically with the issue of whether investors believe the forecasts.

72.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 112 and Appendix C, p. C-10

Risk Adjusted Equity Market Risk Premium

On page 112, Ms. McShane states that "The constant growth model applied to the U.S. utility sample using the consensus of analysts' long-term earnings growth forecasts indicates a cost of equity of approximately 9.3% (Schedule 19). The utility cost of equity based on the sustainable growth model is approximately 8.7% (Schedule 20).

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term to migrate to the expected long-run rate of nominal growth in the economy."

On page C-10, Ms. McShane states that in the three-stage DCF test, she used the long-run nominal rate of growth in GDP of 4.9% based on the consensus of economists forecasts for the period 2013-2023.

72.1 By using a long-run DCF model at the bottom of an economic cycle, doesn't Ms McShane potentially overstate the near term cost of capital because of higher expected growth in later years? If not, why not?

Response:

No, for several reasons. First, in the specific case of the U.S. sample, the near-term forecasts are virtually identical to the GDP forecasts, so the question is moot. Second, if the DCF test is conducted at the bottom of the cycle, and the near-term forecasts have not been normalized to reflect expected earnings over a cycle, if anything, the near-term forecasts would be higher, not lower, than the growth rate expected in perpetuity (i.e., the GDP growth rates). Third, the consensus earnings forecasts are intended to reflect the normalized rate of growth over a cycle, so they should not be influenced by the point in the cycle at which those forecasts are made.

73.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 110-113 and Schedules 19-23

DCF Cost of Equity

On pages 110-113, Ms. McShane estimates the DCF cost of equity using a specified sample of US and Canadian utilities which are listed in Schedules 19-23. On page 33, Mr. Engen provides a graph of 30-year credit spreads for a number of publicly traded Canadian utility companies.

73.1 Please confirm that the specified companies used in the DCF cost of equity estimate are predominantly the publicly traded holding companies of the regulated entities.

Response:

It is confirmed that the specified companies used in the DCF cost of equity estimates are predominantly the publicly traded holding companies of the regulated utilities.

73.2 Please provide, in tabular format, the credit ratings for the specified sample of companies and the credit ratings for their related regulated operating companies.

Response:

Please refer to Attachment 73.2.

73.3 Based on the response to the above question, please comment if the credit ratings for holding companies are lower than their related regulated operating companies?

Response:

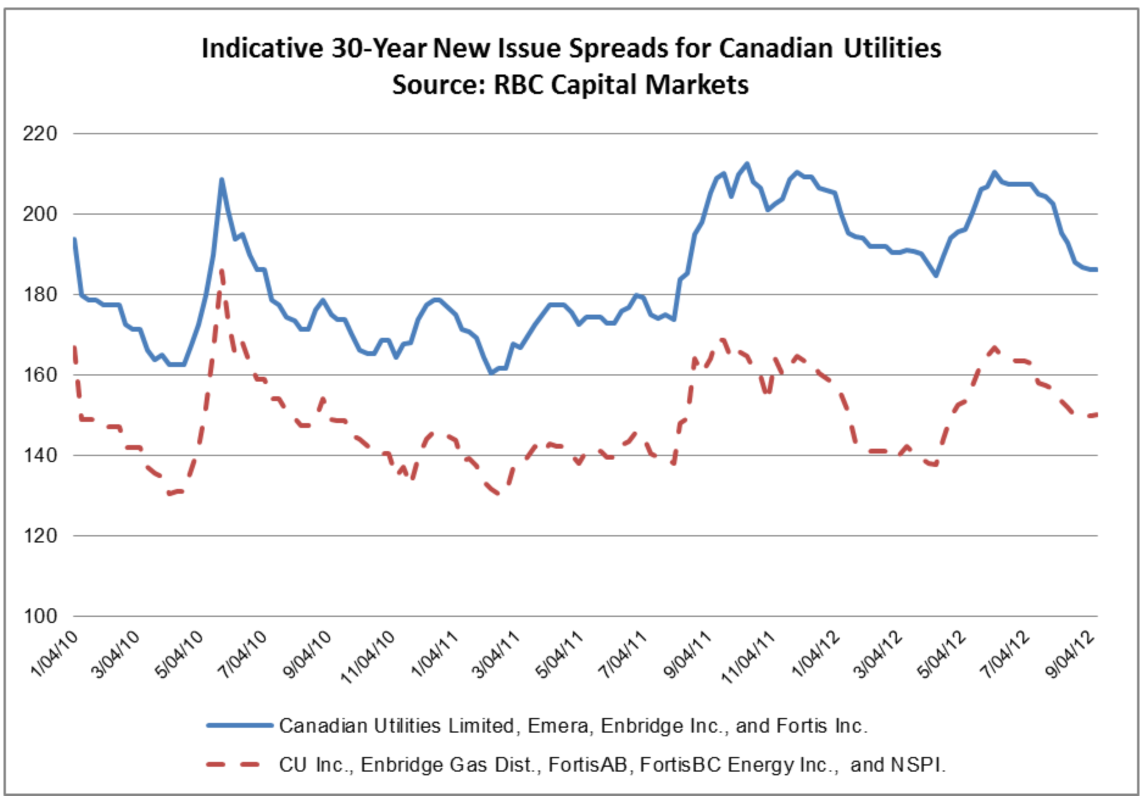
In the case of the S&P ratings for the U.S. utilities, no. For Moody's, for three of the companies, only the publicly-traded entity is rated; two of the utilities only have rated debt at the operating company level; one has the same rating for both the parent and the subsidiary; the remaining six have ratings that are one notch lower at the parent company than at the subsidiary level. For the Canadian utilities' S&P ratings, no. For Moody's, for the two companies which have had Moody's ratings for both the parent and operating companies, the difference is one notch. For

DBRS, for Canadian Utilities, Emera and Enbridge, there is a one notch difference. For Fortis Inc., given the ratings of all the subsidiaries, there is no discernible difference. TransCanada has DBRS ratings only for TransCanada Pipelines.

73.4 For the Canadian sample of utilities, please provide a graph of the 30-year credit spread for the holding companies and their related regulated operating companies.

Response:

The graph below shows the average indicative 30-year credit spreads for Canadian Utilities Limited, Emera, Enbridge Inc., and Fortis Inc. and the average indicative 30-year credit spreads for CU Inc., Enbridge Gas, FortisAlberta Inc., FortisBC Energy Inc. and Nova Scotia Power Inc. from January 2010 to September 10, 2012. TransCanada Corporation is not included as it has not issued any long-term debt; all long-term debt has been issued by TransCanada Pipelines.



73.5 If there is a lower risk premium for the cost of debt for 30 year bonds of the operating companies relative to their related publicly traded holding companies, should there also be a lower risk premium for the cost of equity at the operating company level relative to the holding company?

Response:

The differences in debt ratings, where there is one, and credit spread between the holding companies and the operating companies arise because the debt of the holding companies is subordinated to the debt of the operating companies. The subordination of the debt at the holding company level means that, in the case of bankruptcy or liquidation of the assets, the operating company debt holders have first call on the assets. The holders of the operating company debt are in command if credit problems arise. The holders of the operating company debt control measures taken, e.g., if the firm goes into receivership and is restructured, that determine how much residual value there might be to satisfy claims of the holders of holding company debt. In addition, debt covenants at the operating company level often prohibit providing financial assistance such as lending to, or guaranteeing liabilities of, the holding company without the approval of operating company debt holders. The spreads between yields on debt at the holding and operating company level reflect the value of the senior status and control of the debt holders at the operating company level. This "chain of command" flowing upward from operating company to holding company is unique to debt. In the case of equity, the chain of command flows downward, from holding company to operating company. Consequently, it does not follow that a lower credit spread for the operating company than for the holding company translates to a lower equity risk premium for the operating company than for the holding company. Whether a lower equity risk premium is warranted for an operating company is a function of the lines of business and degree of business risk diversification of the holding company vs. the operating company and the holding company leverage measured in market value terms.

In any event, for Ms. McShane's U.S. utility sample, the reported debt ratings are the ratings for the holding company unless the holding company itself does not have a separate credit rating. As the debt ratings of the holding companies are similar to the ratings of the typical Canadian gas or electric operating utility, there is no basis to even consider an adjustment to their cost of equity. As regards the Canadian utilities, the difference in the cost of long-term debt between the holding companies and the operating subsidiaries has been approximately 35 basis points on average since the beginning of 2010. The only test performed by Ms. McShane that explicitly relies on the cost of equity for the Canadian utility holding companies is the DCF test; the weight given to the DCF test applied to Canadian utilities is relatively small. If the holding companies' higher credit spread were to be considered a proxy for potentially higher overall equity risk, Ms. McShane's overall results would change by less than 10 basis points, too small a difference to change the recommendation.

74.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 115

Risk Adjusted Equity Market Risk Premium

On page 115, Ms. McShane states "The selection should conform to investor perceptions of the risk characteristics of utilities, which are generally characterized by relative stability of earnings, dividends and market prices. These were the principal criteria for the selection of a sample of unregulated companies (from consumer-oriented industries). The criteria for selecting comparable unregulated low risk companies include industry, size, dividend history, capital structures, bond ratings and betas…."

74.1 To what extent should the comparable earning standard adjust for the fact that regulated gas and electric distribution utilities typically have a franchise area that excludes competitors in their core market.

Response:

Ms. McShane does not agree with the premise that a franchise excludes competitors in the core market, as utilities, particularly FEI, compete with other sources of energy in their core markets. Ms. McShane recognizes that regulated utilities have lower business risk than the unregulated companies, in part due to the fact that regulated utilities do have designated franchise areas for specific services. The higher business risk of the unregulated companies, which do not have that benefit, is partly offset by their lower financial risk (higher common equity ratio). Any adjustment to the resulting earnings of the unregulated companies should be for differences in overall (business plus financial) risk between the selected sample of unregulated companies and utilities. Ms. McShane's comparable earnings test includes an adjustment for the differential total risk between the selected sample of unregulated companies and the benchmark utility. There is no need for any further adjustment.

75.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 117-118

Fair ROE for FEI as Benchmark BC Utility

On page 118, Ms. McShane states that "At a minimum, the financing flexibility allowance should be adequate to allow a regulated company to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10 times. At this level, a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 times is approximately 50 basis points. As this financing flexibility adjustment is minimal, it does not fully address the comparable returns standard."

On page 71 of McShane's testimony, Ms. McShane states that "The proxy companies used for the purpose of estimating the cost of equity for the benchmark BC utility have market-to-book ratios of approximately 1.7X (U.S. sample) to 2.6X (Canadian sample), well above the market-to-book ratio of 1.0 that conceptually would equate the return on book value (in dollar terms) to the return estimated by reference to the market-based DCF or equity risk premium tests."

75.1 Please explain the rationale for choosing a financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 times when the proxy companies used for estimating the cost of equity for the benchmark BC utility have market/book ratios of 1.7X to 2.6X?

Response:

The rationale is that, while the actual market/book ratios of the companies are above 1.0, the discounted cash flow and risk premium results are "bare-bones" costs, i.e., the return which conceptually, if applied to the book value of equity, would cause the utility market/book ratio to equal 1.0. In Ms. McShane's judgment, a financing flexibility allowance sufficient to maintain a market/book range of 1.05-1.10 provides the minimum cushion warranted to prevent the impairment of financial integrity. That adjustment is approximately 50 basis points. A reduction in the market/book ratio of the utility to a level below 1.0 is an indicator of the impairment of financial integrity.

75.2 Please calculate the financing flexibility allowance that would be adequate to maintain a market/book in the range of 1.7X to 2.6X?

Response:

The actual measured market/book ratios of utilities reflect a myriad of factors, including expected rate base growth; returns expected from all operations, not just those governed by allowed ROEs; the perceived ability to achieve earnings on regulated operations that are different from the allowed ROEs; differences between historical cost GAAP accounting and economic values of underlying assets, going concern value; and the tenor of the overall equity market (i.e., utility shares will trade on the basis of relative, not absolute, values). If the DCF formula (set out in Ms. McShane's Appendix F, F-3, footnote 42) which underpins the estimate of the 50 basis points referenced in response to BCUC IR 1.75.1 were used in conjunction with the 1.7 to 2.6 market/book ratios, the result is nonsensical. The indicated adjustments are approximately 3.2% for a market/book ratio of 1.7X and 5.8% at a market/book ratio of 2.6X.

75.2.1 Would the resulting financing flexibility allowance be consistent with the comparable returns standard?

Response:

No. As discussed in Appendix F and as set out in the formulas in Schedules 26 and 27, the financing flexibility adjustment for a utility is intended to translate a return on market value into a return on original cost book value. As presented in Appendix F, Table F-1, the incremental return required to fully account for the difference between market value and book value capital structures for both the benchmark sample and the sample of Canadian utilities, i.e. to fully address the comparable returns standard, is estimated in the range of 100 to 200 basis points, mid-point of 150 basis points. Please note that Ms. McShane has recommended reliance on equity risk premium tests, DCF tests and the comparable earnings test. In that case, a financing flexibility adjustment of 50 basis points was recommended. The recommendation of a higher financing flexibility adjustment was presented as an alternative, to apply if only the market-derived cost of equity (equity risk premium and DCF) tests were to be given weight. In that case, the recommended adjustment is 100 basis points, consistent with an implied market/book ratio, at the sample utilities' retention rates of 35% to 40%, of approximately 1.15X to 1.20X.

76.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 116 and Schedule 25; Exhibit B1-9-6, Appendix E, p. 32

Comparable Earnings Test

On page 116 and Schedule 25, Ms. McShane provides ROE information for 21 Canadian low risk unregulated companies for the period 1995 to 2011, which is used in the comparable earnings test. Ms. McShane adjusts the ROE downwards by 125 to 150 basis points to recognize the unregulated companies' higher risk using the typical spread between Moody's BBB-rated long-term industrial bond yields and long-term A-rated utility bond yields and the relative betas.

On page 32, Mr. Engen provides bond spread information of the generic 'A' bonds as of July 6, 2012:

5-year =150 bps, 10-yr = 202 bps, long end = 241 bps.

76.1 Please elaborate on the method and data used to estimate the risk adjustment.

Response:

As stated in Appendix E, page E-4, the period 2004-2011 was selected as the appropriate period over which to calculate experienced returns as nominal growth is forecast to be only slightly higher than that experienced over the earlier period. In estimating the adjustment to the returns on equity shown in Table E-2 for the low risk Canadian unregulated companies, two calculations were made. The adjustment is based on the mid-point of these two calculations.

The first calculation is the average monthly spread between yields on Canadian BBB-rated long-term corporate bonds and the yield on the Bloomberg A-rated Canadian Utility 30 Year Index over the period 2004 to 2011. The footnote at page 116 incorrectly references the Moody's data series. The BBB-rated long-term corporate bond yield series is the DEX Corporate BBB Long Term Bond Index. The average monthly spread between the two series over the period 2004 to 2011 was 75 basis points.

To ensure that the adjustment was not understated, the second estimate used the CAPM model to adjust the indicated return on equity for the unregulated sample. From Schedule 14, page 1 of 6 and Schedule 24, the median adjusted betas for the period 2004-2011 are as follows:

	2004-2011
Canadian Utilities [1/]	0.48
Canadian Unregulated	0.64
Relative Beta (0.48/0.63)	75%

[1/] Average of annual medians.

Using the relative betas and the long-term forecast for the 30-year Canada bond of approximately 5.0%, as set forth on page 30 of Ms. McShane's testimony, the adjusted ROE was calculated as shown in the table below:

	Table E-2 ROEs	Adjusted Premium
	(1)	(2) = Relative Beta * (Col. 1 - 5.0%)
Average	13.2%	6.2%
Median	12.3%	5.5%
Average of Annual Medians	13.5%	6.4%
Average	**13.00%**	**6.0%**
Forecast 30 Year Canada Bond Yield		5.00%
Adjusted ROE		**11.0%**
Indicated Adjustment (basis points)		**200**

The midpoint of the two calculated adjustments was approximately 137 basis points, or in the range of 125 to 150 basis points.

76.2 Please provide historical data for the Moody's BBB-rated long-term industry bond yields and the long-term A-rated utility bond yields.

Response:

As noted in response to BCUC IR 1.76.1, the footnote at page 116 incorrectly references the Moody's data series. The BBB-rated long-term corporate bond yield series is the DEX Corporate BBB Long Term Bond Index. The Bloomberg and DEX series provided in response to this question are proprietary and under strict-use licence. Therefore, the data are being provided confidentially under separate cover to the Commission only for the purposes of this proceeding, and cannot be provided to other parties under the terms of the license. Please see Attachment 76.2.

76.3 The risk premium for corporate bonds versus a similar maturity risk free government bond appears to grow larger as the bond maturity rises based on the information provided by Mr. Engen. Please confirm that risk premiums typically rise as the maturity of the instrument lengthens.

Response:

It is confirmed.

76.4 Should the relative equity risk premium between a BBB rated industrial and an A rated utility be higher than the associated bond risk premium?

Response:

The adjustment was higher than the spread, as explained in response to BCUC IR 1.76.1.

77.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. A-7

On page A-7, Ms. McShane quotes from the *Triumph of the Optimists*, which discusses an example of returns that can vary between +25% and -20% to demonstrate the difference between the arithmetic mean return of 2.5% and the geometric mean return of 0%. The authors conclude that "The 2 ½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns."

77.1 What is the approximate volatility and standard deviation of the returns in the example provided?

<u>Response:</u>

The example and numbers provided by the authors in the *Triumph of the Optimists* were for illustrative purposes only to demonstrate why the arithmetic average, as opposed to geometric average, is the appropriate measure for the estimation of the cost of equity. The illustrative numbers, comprised of a series of two (+25 and -20), are not "real" return data. The text from the *Triumph of the Optimists* was provided by Ms. McShane as independent support for the conclusion that arithmetic, not geometric averages, should be used when estimating the market risk premium from historic market data.

77.2 How does this compare to the standard deviation of U.S. ROE decisions as shown in the concentric Energy Advisors report in Exhibit B1-9-6, appendix I, page 28.

<u>Response:</u>

There is no basis for comparison as the values provided in the *Triumph of the Optimists* are not real data.

77.3 How does this compare to the standard deviation of Canadian ROE decisions?

<u>Response:</u>

Please refer to the response to BCUC IR 1.77.2.

78.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, p. 117

On page 117, the topic of flotation costs is discussed.

78.1 It is recognized that flotation costs are widely accepted across Canadian regulatory decisions. Please elaborate on the process and data used to estimate the flotation costs.

Response:

The preamble to this question states "It is recognized that flotation costs are widely accepted across Canadian regulatory decisions." To clarify, the discussion at page 117 concerns the broader topic of the financing flexibility adjustment, which incorporates, but is not limited to, flotation costs. Ms. McShane's testimony states that "it is the normal practice of Canadian regulators to add an adjustment for financing flexibility to the estimated market-based utility cost of equity." (lines 2983 to 2985).

Ms. McShane defines flotation costs at page F-1, where she states:

> *"The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle."*

A review of Canadian cost of capital decisions indicates that regulators sometimes use the term flotation costs to refer solely to flotation costs as defined in point (1) above, sometimes to refer more broadly to the financing flexibility allowance and sometimes they use the term financing flexibility adjustment.

Ms. McShane's responses to this series of questions are premised on the assumption that the references to flotation costs are as defined as in point (1) in the citation above from Ms. McShane's Appendix F-1.

Ms. McShane is only aware of three recent decisions other than the 2009 ROE decision that have addressed the question of flotation costs in the more narrow context defined above. All were decisions of the Régie de l'énergie, for Gaz Métro in Régie de l'énergie, Décision D-2009-156, December 7, 2009 and Décision D-2011-182, November 25, 2011) and for Gazifère (Régie de l'énergie, Décision D-2010-147, November 26, 2010. In Decision D-2009-156 for Gaz Métro, the Régie established the allowance for issuance costs at 30 to 40 basis points after a review of Gaz Métro's actual equity issuance costs since 1993. However, the 30 to 40 basis point allowance does not appear to have been based on the actual issuance costs. Instead, the magnitude of the actual issuance costs incurred was used to assess the reasonableness of a 30 to 40 basis point allowance. In Decision D-2011-182, the Régie referred back to the 2009 examination of flotation costs in adopting the same 30 to 40 basis point range. In Décision D-2010-147 for Gazifère, the Régie noted that it did not have data on actual issuance costs for the company, as unlike Gaz Métro, Gazifère does not directly issue equity in the capital market. The Régie approved a theoretical flotation cost allowance of 50 basis points.

78.2 Please discuss the circumstances that cause the flotation costs to change.

Response:

Flotation costs as defined in response to BCUC IR 1.78.1 above would change as a result of changes in the magnitude of underwriter and administrative fees associated with a particular issue and the type of issuance, i.e. whether the equity issued is a "bought deal" or fully marketed deal. The magnitude of flotation costs would also change if there were a systematic change in the extent to which the share price was diluted (market pressure) when new shares are issued into the market.

78.3 Please discuss any trends or changes in flotation costs over the last 10 years.

Response:

Ms. McShane has not undertaken any studies of flotation costs as defined in response to BCUC IR 1.78.1, and is unable to comment on the trends in those costs over the past 10 years.

78.3.1 What level of flotation costs have been accepted by the various energy utility regulatory tribunals in Canada over the past 10 years?

Response:

The table below shows the trends in the allowed level of flotation costs and/or financing flexibility adjustments where applicable. Manitoba and Saskatchewan are excluded as they have no investor-owned utilities whose allowed returns are set in the traditional manner. In New Brunswick, the only utility that is regulated on a rate of return/rate base approach is Enbridge

Gas New Brunswick (EGNB). In its 2010 cost of capital decision for EGNB, the regulator allowed 50 basis points based on the evidence of the experts that an amount for flotation costs was necessary. To Ms. McShane's knowledge, that was the first time the New Brunswick regulator had addressed the issue. Nova Scotia and Prince Edward Island are excluded as the decisions reviewed are silent on the issue. With respect to the National Energy Board, there have been only three cost of capital decisions in the past ten years, for TransCanada Pipelines in 2002 and 2004 and for TQM in 2009. In its 2002 decision, the NEB did not address the issue of flotation costs, concluding that its RH-2-94 formula continued to provide appropriate ROEs for TCPL. The 2004 decision dealt with capital structure only. The 2009 TQM decision, which adopted the After-tax Weighted Average Cost of Capital approach, did not address flotation costs.

Jurisdiction	Year of Decision	Allowance Approved	Description
British Columbia	1994	50 bps	covers risk of dilution and cost of new share issues in "other than extraordinary market circumstances"
	2006	25 bps explicitly added to DCF	will not automatically add 50 basis points, but will use judgment each time. Decision does not specify whether allowance added to tests other than DCF
	2009	25 bps DCF, CAPM, and ERP and an additional 50 bps to CAPM	25 basis points for financing and market pressure costs arising at the time of the sale of new equity. The 50 basis points additional for CAPM described as for the "fairness" principles
Alberta	2004	50 bps	appropriate for "flotation costs and financing flexibility"
	2009	50 bps	flotation allowance to "account for administrative costs and issuance costs for the investment banker, any impact of under-pricing a new issue and the potential for dilution."
	2011	50 bps	issuance costs as an element of flotation allowance added to both CAPM and DCF test results
Ontario	2002	50 bps	Described as an "allowance for financial flexibility"
	2006	50 bps	"..for floatation and transaction costs", implicit in the equity risk premium. This "has been the case ever since the Board first introduced the premium in the early 1990s, and that similar treatment is used by other Canadian regulators."
	2009	50 bps	the equity risk premium "includes an implicit 50 basis points for transactional costs."

Jurisdiction	Year of Decision	Allowance Approved	Description
Quebec	2011 (Gaz Métro)	30-40 bps	Refer to the response to BCUC IR 1.78.1 above
	2010 (Gazifère)	50 bps	Refer to the response to BCUC IR 1.78.1 above
	2009 (Gaz Métro)	30-40 bps	Refer to the response to BCUC IR 1.78.1 above
	2007 (Gaz Métro)	30 bps	issuance costs and other costs of accessing market not examined in detail in case, maintained 30 basis points established in 1999. The 1999 decision states that the 30 basis points previously accepted were maintained.
Newfoundland and Labrador (Newfoundland Power)	1998/99	50 bps	to "cover underwriting costs, the risk of dilution of share value and unforeseen circumstances"
	2003	0	Board noted 2 of 3 experts did not make an allowance and believed the application of financing flexibility adds a degree of subjectivity. The issue is best considered within the context of the equity risk premium test
	2007	N/A	return on rate base was a negotiated settlement
	2009	50 bps	"appropriate to add an allowance for financing flexibility"

79.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, Schedule 3 p. 1 of 2; Schedule 5, pp. 1 to 2

Preferred Shares

Ms. McShane in Schedule 3 page 1 of 2 – Equity Return Awards and Capital Structures Adopted by Regulatory Boards for Canadian Utilities includes columns for Debt, Preferred Stock, and Common Stock Equity. Schedule 5 also includes a column for Preferred Stock.

79.1 Please confirm that many utility holding companies have issued preferred shares in the last 5 years. Please provide a general overview.

Response:

Ms. McShane is aware that Canadian Utilities Ltd., Emera, Enbridge Inc. and Fortis Inc. have issued preferred shares in the past five years. Canadian Utilities Ltd. issued perpetual preferred shares in June and July of 2012, taking advantage of a brief opening in that market. Both issues were used to redeem outstanding issues. Emera Inc. issued $250 million of five-year rate reset preferred shares in May 2012. Fortis Inc. issued $250 million of five-year rate reset preferred shares in January 2010. Enbridge Inc. announced a $400 million five-year rate reset preferred share issue in September 2012, issued $450 million of five-year rate reset preferred shares in July 2012, U.S. $400 million of five-year rate reset preferred shares in May 2012, $350 million of five-year rate reset preferred shares in March 2012 and $500 million of five-year rate reset preferred shares in January 2012.

79.2 With regards to Schedule 3 page 1 of 2, please elaborate on the historical presence of preferred equity in utility companies.

Response:

The following utilities on Schedule 3 had some preferred shares in their regulated capital structure as of their most recent decision establishing capital structure: ATCO Electric, ATCO Gas, Enbridge Gas, Gaz Métro, Pacific Northern Gas-West, Union Gas, Newfoundland Power and Nova Scotia Power. Gaz Métro's preferred shares are deemed preferred shares, i.e., they have not actually issued preferred shares. PNG redeemed its preferred shares after it was acquired by AltaGas Ltd., so that it would no longer incur the costs of being a reporting issuer. The outstanding preferred shares of Enbridge Gas, Union Gas and Newfoundland Power are perpetual preferred shares that were issued more than 25 years ago. Nova Scotia Power's preferred share and debt components on Schedule 3 are out of date. Nova Scotia Power redeemed one of its preferred share issues in 2009; its most recent approved regulated capital structure contains 58.8% debt and 3.6% preferred shares. The remaining preferred shares were issued in 2000. CU Inc., the company which raises debt and preferred shares on behalf of its utility operating entities (the ATCO Utilities), is the only company which has issued new preferred shares in more than a decade. Preferred shares were a more common component of utility capital structures prior to the repeal of the Public Utility Income Tax Transfer Act (PUITTA) in the mid 1990s. Prior to repeal of the statute, utilities issued perpetual preferred shares, which provided support to credit metrics. Under PUITTA, the federal income taxes that were collected in the utilities' revenue requirement associated with the preferred share dividends were rebated to the provinces, and then, in some cases (e.g., Alberta), were rebated to customers. In the mid-1990s, after PUITTA was repealed and the Canadian Institute of Chartered Accountants (CICA) changed the accounting treatment for some categories of preferred shares, requiring them to be reported as liabilities, preferred share issuance by utilities became quite limited.

79.3 With regards to Schedule 3 page 1 of 2, please elaborate on the recent activity of preferred equity in utility operating companies (not holding companies). If there has been little recent activity, please comment on why utility operating companies have not issued preferred equity relative to the extent of utility holding companies?

Response:

Please refer to the response to BCUC IR1.79.2, with respect to recent activity by utility operating companies. In regard to why operating companies have not issued preferred shares to the same extent that holding companies have, the preferred market generally has frequently been closed to new issues of any kind. Operating companies seek to maintain relatively stable proportions of various forms of capital in their capital structure and thus need to be able to depend on a market being open when they need to raise capital. There has been very limited market demand for perpetual preferred shares. The principal demand has been for five-year rate reset issues, whose cost is subject to change every five years. The dividend is only fixed for five years, after which it is reset at a specified spread to the five-year Canada bond. In the only case in recent years where the issue of preferred shares in a utility's capital structure has been addressed by a regulator, for the ATCO Utilities, the regulator considered whether preferred shares were a cost-efficient replacement for debt. It is Ms. McShane's understanding that the bulk of the recent issuances of five-year reset preferred shares by holding companies have been undertaken as a short-term means of adding a form of equity to their balance sheet during a period of high capital expenditures. Once the assets being financed are in service, and begin to produce cash flow, common equity will increase via retained earnings and the preferred shares can be redeemed.

79.4 Please confirm that BC Gas Utility Ltd. (now FortisBC Energy Inc.) and PNG previously had preferred equity in their capital structure.

Response:

Confirmed. FEI (then BC Gas Utility) agreed, as part of the revenue requirements negotiated settlement for 1998-2002 to redeem its retractable preferred shares, treated as debt for accounting and credit rating purposes, when they became redeemable in 1999 and 2000 and replace them with debt. PNG redeemed its outstanding preferred share issue earlier this year, as stated in response to BCUC IR 1.79.2.

79.5 In the opinion of Ms. McShane, please comment on preferred equity in a utility's capital structure including its purpose, appropriateness, regulatory treatment, accounting treatment, credit rating agency treatment, and nature of funding source relative to debt and common equity.

Response:

Since the market for preferred shares is virtually limited to five-year rate reset preferred shares, Ms. McShane has focused her response to the question on that type of preferred shares. Given the characteristics of those preferred shares, they are appropriately viewed as a replacement for debt, however, are typically less efficient than debt due to tax and rate considerations. Ms. McShane is not aware of any instances for Canadian utilities where it would be appropriate to add preferred shares to the capital structure to replace (reduce) common equity. Please refer to the response to BCUC IR 1.14.6.

To Ms. McShane's knowledge, there have been no decisions in recent years for any of the utilities with "heritage" preferred shares in the capital structures regarding how regulators treat or view preferred shares. Ms. McShane understands from discussions with Nova Scotia Power that its preferred shares are viewed by its regulator as debt. Preferred shares are also considered to be a replacement for debt for the ATCO Utilities. PNG has applied to the Commission to replace its recently redeemed perpetual preferred issue with a combination of debt and equity, to maintain a total equity ratio of close to 50% as DBRS had indicated was required to maintain the BBB(low) debt rating. No decision had been issued as of September 18, 2012.

As regards accounting treatment, Nova Scotia Power's preferred shares, which are redeemable fixed dividend preferred shares, exchangeable at the option of the holder into Emera common shares, are treated for accounting purposes as mezzanine financing, outside of equity. The "heritage" fixed dividend perpetual preferred shares of Enbridge Gas *et. al*. and the preferred shares of CU Inc. are treated for accounting purposes as part of shareholders' equity.

As regards credit rating agency treatment, the debt rating agencies give them different equity credit, depending on the specific features of the issue. For example, S&P and Moody's give the five-year reset preferred shares 50% equity credit.

80.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, Schedule 3 p. 1 of 2; Schedule 5, pp. 1 to 2

CU Inc. - Preferred Shares

In Schedule 3, page 1 of 2 of Ms. McShane's evidence illustrates ATCO Gas with a 7.91 percent portion for Preferred Stock. Also it shows ATCO Electric Transmission at 10.19 percent and ATCO Electric Distribution at 10.05 percent.

CU Inc. issued a Short Form Prospectus, New Issue, dated November 24, 2010 for $75 million, 3,000,000 shares with 25.00 par value per share to yield 3.80 percent per annum. The PDF of the prospectus is located at:

http://www.canadianutilities.com/CU-Inc/Documents/prospectus_Cumulative_Redeemable_Preferred_Shares_Series_4.pdf

Page 4 of the CU Inc. prospectus states:

> **"USE OF PROCEEDS**
>
> The estimated net proceeds (after deducting the Underwriters' Fee) to be received by the Corporation from the sale of the Series 4 Preferred Shares are $72,750,000, assuming that no Series 4 Preferred Shares are sold to institutions. The Corporation intends to use the proceeds to purchase preferred shares to be issued by its operating subsidiaries, ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd. It is expected that these subsidiaries will use the proceeds to fund a portion of their 2010 capital expenditure programs."

80.1 Please explain the relationship between CU Inc. and its operating subsidiaries ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd.

Response:

CU Inc. is the parent of ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd. CU Inc. is the debt and preferred financing vehicle for the two subsidiaries.

80.2 Please explain how the operating subsidiaries are allocated debt and preferred shares from CU Inc. Do the regulated operating subsidiaries account for the debt and preferred shares with the interest rates (for debt) and dividend rates (for preferred shares) without markup from CU Inc.

Response:

CU Inc. raises debt and preferred equity funds on behalf of the two subsidiaries. Debt and preferred shares are issued by CU Inc. based on the requirements of the two subsidiaries for capital expenditures and maintenance of the regulated capital structures. Those issues are allocated to the subsidiaries on that basis. The subsidiaries enter into back-to-back agreements with CU Inc. on the same terms as CU Inc. raised the funds in the public markets.

80.3 What is the reasoning why CU Inc. issued preferred shares? How do new issuances of preferred shares advantage or disadvantage existing debt holders and existing common shareholders of CU Inc.?

Response:

CU Inc. raises preferred shares to support its credit metrics and to maintain its existing credit ratings, currently A(high) by DBRS and A by S&P. It uses preferred shares as a replacement for debt. The preferred shares advantage debt holders as they support credit metrics but are subordinate to debt. They have no impact on the common equity shareholders.

80.4 How does the Alberta Utilities Commission (AUC) take into account the preferred equity of CU Inc. for the capital structures of the regulated utilities by the AUC? Please elaborate and provide any relevant decisions.

Response:

In the 2004 Generic Cost of Capital Decision (Decision 2004-052), the first generic cost of capital proceeding, the predecessor to the AUC evaluated the common equity ratios of the utilities as if they had no preferred shares. In that decision, the Board concluded that:

> *"The Board has recognized in previous decisions that during the period of time when income tax rebates were in place, it was prudent to utilize preferred share financing in place of debt.*
>
> *However, the Board considers that there may be merit in further consideration of the appropriateness of the continuing use of preferred shares as a form of financing, to*

> *understand the redemption options and to fully explore the related implications and options."* (page 55)

The Alberta regulator later considered the matter in the ATCO Utilities Common Matters Proceeding, and in Decision 2006-100, found that:

> *"The Board considers the evidence provided by AU and its experts persuasive that the discontinuance of the use of preferred shares could be expected in the present market conditions to increase AU's debt costs by approximately 10 basis points. The Board also notes that AU's evidence indicated that the impact could be as high as 60 basis points. Therefore the Board finds that the continued use of preferred shares is cost effective at this time.*
>
> *Therefore, the Board accepts that some level of preferred shares can to be utilized by AU at this time."* (page 20)

A copy of the relevant excerpts from Decision 2004-052 and a copy of Decision 2006-100 are provided in Attachment 80.4.

81.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide

Exhibit B1-9-6, Appendix G, pp. 8, 9

Market Values of a Firm's Debt and Equity

Dr. Vander Weide opines that economists measure a firm's capital structure in terms of the market values of its debt and equity and investors measure the expected return on their investment portfolios using market value weights rather than book value weights.

81.1 Notwithstanding the relative costs of debt and equity, is it not true that different companies search for optimal capital structure appropriate to their respective economic sector and their respective stage of maturity?

Response:

Dr. Vander Weide agrees that companies generally consider industry sector and stage of maturity, among other variables, when choosing their optimal capital structure. In this regard, Dr. Vander Weide notes that: (1) his proxy groups of utilities are in the same industry sector (utility sector) and stage of maturity (mature) as FEI; and (2) his proxy groups of US utilities have significantly higher equity ratios than FEI.

82.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide

Exhibit B1-9-6, Appendix G, p. 8

Fair Rate of Return Standard

On page 8 of Dr. Vander Weide's testimony, Dr. Vander Weide notes that "…the cost of equity is greater than the cost of debt."

82.1 Please confirm that this is because equity investments are perceived by investors to be generally riskier than debt. If not, please explain why not?

Response:

Confirmed.

83.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide
Exhibit B1-9-6, Appendix G, p. 19
Comparable Risk Utilities

On page 19 of Dr. Vander Weide's testimony, Dr. Vander Weide states "…(2) reasonable estimates of expected growth rates are available for these companies, whereas the same data are not available for the Canadian utilities";

83.1 Please explain what is meant by "reasonable estimates of expected growth rates"; what sources of reasonable estimates of expected growth were considered; and why alternatives sources of 'reasonable estimates' were rejected?

Response:

In referring to a "reasonable estimate" of expected growth, Dr. Vander Weide means a growth estimate that reflects investors' growth expectations for the proxy companies. For the reasons discussed on page 28 of his evidence, Dr. Vander Weide believes that analysts' projections of future EPS growth are the most reasonable estimate of investors' expected growth rates for the companies in his proxy groups of utilities. Dr. Vander Weide uses the mean analysts' EPS growth forecasts published by I/B/E/S Thomson Reuters because the I/B/E/S growth forecasts have been shown to be more highly correlated with stock prices than either historical or retention growth estimates. As discussed on page 30 of his evidence, Dr. Vander Weide also believes that the mean I/B/E/S growth forecast is a more reliable proxy for investors' growth estimates if there are at least two analysts' growth forecasts included in the I/B/E/S mean.

83.2 What sources of reasonable estimates of expected growth rates for Canadian companies are available and why were they rejected?

Response:

Dr. Vander Weide is aware that information on expected long-term growth forecasts for Canadian companies may now be available from Reuters.com and Yahoo.com. However, Dr. Vander Weide has purchased analysts' long-term growth forecasts for many years from I/B/E/S Thomson Reuters, and there generally have been few analysts reporting long-term EPS growth forecasts for Canadian utilities. Given the lack of long-term growth forecasts for the Canadian utilities and the small number of publicly-traded Canadian companies with a high percentage of assets associated with natural gas and electric distribution activities, Dr. Vander Weide did not apply the DCF model to Canadian utilities.

84.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide

Exhibit B1-9-6, Appendix G, p. 22

Comparable Risk Utilities

On page 22 of Dr. Vander Weide's testimony, Dr. Vander Weide states "…the risk of investing in a company's stock is best measured by the expected variability in the return on the stock investment."

84.1 Over what time period is Dr. Vander Weide referring to when discussing the expected variability in the return on the stock investment? Please explain.

Response:

Dr. Vander Weide does not have a specific time horizon in mind in the referenced statement. Rather, the referenced statement is a general statement that refers to the proper measurement of the risk of investing in a company's stock regardless of the investor's time horizon. However, in practice, Dr. Vander Weide believes that investors measure the risk of investing in stocks over relatively long horizons because stocks are long-term investments with no stated maturity. The essential long-run nature of stock investments is true even if investors expect to sell stock in the short run because the price at which the stock can be sold depends on the expected cash flows from investing in the stock over all future years over the life of company whose stock is sold.

84.2 In the sentence above, is Dr. Vander Weide referring to the absolute variability in the return on the stock investment or to the variability relative to other potential investments?

Response:

Dr. Vander Weide's statement refers to the absolute variability in the return on the stock investment.

84.2.1 If the variability is relative to other potential investments, do investors look at the entire universe of investments available to them or to a subset, and if so, which subset.

Response:

Please refer to the response to BCUC IR 1.84.2.

85.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide

Exhibit B1-9-6, Appendix G, p. 24; Exhibit A2-21 OEB Report of the Board on the Cost of Capital (December 11, 2009)

Comparable Risk Utilities

Dr. Vander Weide quotes on page 24 of his testimony, the National Energy Board, as saying "…that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008."

85.1 Can Dr. Vander Weide confirm that the NEB also said in RH-1-2008: "In assessing the comparability of U.S. LDC returns, the Board's view regarding the higher short-term risks of U.S. LDCs meant that, overall, the Board viewed the regulated LDC activities of this group as somewhat higher risk than TQM." (RH-1-2008, p. 68).

Response:

Confirmed.

Dr. Vander Weide quotes on p. 24 of his testimony, from the Ontario Energy Board's "Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. That quote states in part that "In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed." (Exhibit A2-21)

85.2 Can Dr. Van Dr. Weide confirm that the OEB also said in that section that "The Board notes that Concentric did not rely on the entire universe of U.S. utilities for its comparative analysis. Rather, Concentric carefully selected comparable companies based on a series of transparent financial metrics, and the Board is of the view that this approach has considerable merit. Commenting on Concentric's analysis, Union Gas noted that no one else in the consultation performed this kind of detailed analysis of U.S. comparators. The use of a principled, analytical, and transparent approach to determine a low risk comparator group from a riskier universe for the purpose of informing the Board's judgment was supported by various participants in the consultation." (OEB Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, p. 22)

Response:

Confirmed.

85.3 As Dr. Vander Weide was also a participant in the OEB proceeding, can he describe how the universe of U.S. companies he has selected for inclusion in his analysis in the current BCUC proceeding differs from the Concentric selected comparables used in the OEB proceeding?

Response:

Dr. Vander Weide's evidence is similar to Concentric's evidence in the OEB proceeding in that both Dr. Vander Weide and Concentric begin their analyses of comparables by comparing the risk of investing in U.S. utilities to the risk of investing in Canadian utilities. From these assessments, Dr. Vander Weide and Concentric both conclude that business and operating risks of U.S. and Canadian utilities are similar because they operate in similar economic environments, are regulated under similar regulatory philosophies, and have similar regulatory cost adjustment mechanisms. Dr. Vander Weide's evidence is also similar to Concentric's evidence in that Dr. Vander Weide and Concentric both base their selection of proxy companies on transparent financial metrics and both give substantial weight to the results of cost of equity models applied to U.S. natural gas and electric utilities. The relatively minor differences in Dr. Vander Weide's and Concentric's comparable companies result from slight differences in proxy company selection criteria. As described in his evidence in this proceeding, Dr. Vander Weide uses a larger and a smaller group of U.S. utilities to estimate FEI's cost of equity. As he describes in his filed evidence on page 29, for his larger group of utilities, Dr. Vander Weide selects U.S. publicly-traded natural gas and electric utilities that:

> *(1) paid dividends during every quarter and did not decrease dividends during any quarter of the past two years; (2) have at least two analysts included in the I/B/E/S mean growth forecast; (3) are not in the process of being acquired; (4) have a Value Line Safety Rank of 1, 2, or 3; and (5) have an investment grade S&P bond rating.*

For his smaller group of utilities, Dr. Vander Weide selects those utilities from his larger group that "have at least 80 percent of total assets devoted to regulated utility operations and that have an S&P bond rating of BBB or higher." [Vander Weide Appendix G, page 29]

As described in Concentric's report in the OEB proceeding, Concentric selected natural gas utilities with: (1) S&P credit ratings greater than or equal to BBB and less than or equal to A+;

and (2) greater than sixty percent revenue from regulated operations [Concentric OEB report, Appendix C, page C-1]. Concentric selected electric utilities with credit ratings equal to or greater than A- and greater than sixty percent revenue from regulated operations. [Concentric OEB report, Appendix C, page C-2]. Concentric also reduced their electric utility cost of equity result by forty basis points to reflect what, in their opinion, is the risk difference between integrated electric operations and electric distribution-only operations.

In summary, both Dr. Vander Weide and Concentric rely on similar transparent financial metrics to select comparable utilities, reach similar conclusions regarding the usefulness of applying cost of equity models to U.S. comparables to estimate the cost of equity for Canadian utilities, and reach similar conclusions regarding the fair rate of return for Canadian utilities.

86.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide

Exhibit B1-9-6, Appendix G, p. 27 and Exhibits 6 and 7

Comparable Risk Utilities

On page 27 of Dr. Vander Weide’s testimony, Dr. Vander Weide states that “The quarterly DCF model requires an estimate of the dividends, d1, d2, d3, and d4, investors expect to receive over the next four quarters. I estimate the next four quarterly dividends by multiplying the previous four quarterly dividends by the factor, (1 + the growth rate, g).”

86.1 How sensitive is the estimate of the return expected by investors to the growth estimates?

Response:

Because the DCF model states that a company’s cost of equity is equal to the dividend yield plus the growth rate, the DCF-estimated cost of equity is sensitive to the estimates of investors’ growth expectations. In this regard, the DCF is similar to other cost of equity models, such as the CAPM, which require estimates of unknown variables. Specifically, the CAPM is highly sensitive to estimates of the risk-free rate, the beta, and the expected risk premium on the market portfolio. Thus, in the case of the DCF model, the dividend yield is directly observable from stock prices and dividends, but the growth term is not directly observable. In the case of the CAPM, not one of the terms is directly observable (risk-free rate is observable, but not clear whether use short or long or actual or forecast).

86.2 Please provide sensitivity analyses of Exhibits 6 and 7 showing the model result if the growth rate is increased and decreased by respectively 15 percent, 25 percent and 50 percent.

Response:

For the reasons discussed in response to 86.1, Dr. Vander Weide does not believe that the requested calculations provide helpful information for the Commission to evaluate DCF model results compared to results of other models such as the CAPM. All cost of equity models require estimates of unknown parameters, and model results are sensitive to the estimates used. In addition, Dr. Vander Weide notes that the long-term growth forecast he uses in his DCF model for each company is an average of all the contributing analysts’ growth forecasts, and it is unlikely that the average analysts’ long-term growth forecast would differ by the percentages suggested in this question. Nonetheless, the requested information is provided. The table below shows the model results if growth rates are increased by 15 percent, 25 percent, and 50 percent; the model results change by the same percentage in the opposite direction if growth rates are changed downward by the same percentages.

Table 1
Change in Model Results When Growth Changes by 15%, 25%, and 50%
Exhibit 6 Utilities

LINE NO.	COMPANY	GROWTH	G*115%	G*125%	G*150%	AS FILED MODEL RESULT	MODEL RESULT 115% G	MODEL RESULT 125% G	MODEL RESULT 150% G
1	AGL Resources	3.57%	4.11%	4.46%	5.36%	8.6%	9.1%	9.5%	10.5%
2	Alliant Energy	6.35%	7.30%	7.94%	9.53%	10.8%	11.8%	12.5%	14.1%
3	Amer. Elec. Power	3.53%	4.06%	4.41%	5.30%	8.8%	9.3%	9.7%	10.7%
4	Atmos Energy	4.37%	5.03%	5.46%	6.56%	9.0%	9.7%	10.2%	11.3%
5	CenterPoint Energy	4.18%	4.81%	5.23%	6.27%	8.5%	9.2%	9.6%	10.7%
6	CMS Energy Corp.	5.96%	6.85%	7.45%	8.94%	10.4%	11.4%	12.0%	13.6%
7	Consol. Edison	3.15%	3.62%	3.94%	4.73%	7.5%	8.0%	8.3%	9.2%
8	Dominion Resources	5.40%	6.21%	6.75%	8.10%	9.7%	10.5%	11.1%	12.5%
9	DTE Energy	4.29%	4.93%	5.36%	6.44%	8.9%	9.5%	10.0%	11.1%
10	Duke Energy	3.51%	4.04%	4.39%	5.27%	8.5%	9.1%	9.5%	10.4%
11	FirstEnergy Corp.	3.15%	3.62%	3.94%	4.73%	8.2%	8.7%	9.1%	9.9%
12	G't Plains Energy	9.75%	11.21%	12.19%	14.63%	14.6%	16.2%	17.2%	19.8%
13	Hawaiian Elec.	8.03%	9.23%	10.04%	12.05%	13.5%	14.7%	15.6%	17.8%
14	NextEra Energy	5.38%	6.19%	6.73%	8.07%	9.3%	10.2%	10.7%	12.1%
15	NiSource Inc.	9.63%	11.07%	12.04%	14.45%	14.0%	15.5%	16.5%	19.1%
16	Northeast Utilities	6.06%	6.97%	7.58%	9.09%	9.4%	10.4%	11.0%	12.6%
17	Northwest Nat. Gas	3.25%	3.74%	4.06%	4.88%	7.4%	7.9%	8.2%	9.1%
18	Pepco Holdings	4.85%	5.58%	6.06%	7.28%	11.1%	11.9%	12.4%	13.7%
19	Piedmont Natural Gas	4.55%	5.23%	5.69%	6.83%	8.7%	9.4%	9.9%	11.1%
20	Pinnacle West Capital	6.22%	7.15%	7.78%	9.33%	11.1%	12.1%	12.8%	14.4%
21	PNM Resources	9.25%	10.64%	11.56%	13.88%	12.5%	13.9%	14.9%	17.3%
22	Portland General	4.13%	4.75%	5.16%	6.20%	8.7%	9.3%	9.8%	10.9%
23	Public Serv. Enterprise	3.60%	4.14%	4.50%	5.40%	8.4%	9.0%	9.4%	10.3%
24	SCANA Corp.	4.63%	5.32%	5.79%	6.95%	9.3%	10.0%	10.5%	11.7%
25	Sempra Energy	7.05%	8.11%	8.81%	10.58%	10.7%	11.8%	12.6%	14.4%
26	Southern Co.	5.58%	6.42%	6.98%	8.37%	10.2%	11.1%	11.7%	13.2%
27	TECO Energy	4.11%	4.73%	5.14%	6.17%	9.4%	10.1%	10.5%	11.6%
28	Vectren Corp.	5.00%	5.75%	6.25%	7.50%	10.2%	11.0%	11.6%	12.9%
29	Westar Energy	5.80%	6.67%	7.25%	8.70%	10.9%	11.8%	12.4%	14.0%
30	WGL Holdings Inc.	4.60%	5.29%	5.75%	6.90%	8.8%	9.6%	10.0%	11.3%
31	Wisconsin Energy	5.35%	6.15%	6.69%	8.03%	8.6%	9.5%	10.0%	11.4%
32	Xcel Energy Inc.	5.27%	6.06%	6.59%	7.91%	9.5%	10.3%	10.9%	12.3%
33	Average					9.8%	10.7%	11.3%	12.7%

Table 2
Change in Model Results When Growth Changes by 15%, 25%, and 50%
Exhibit 7 Utilities

LINE NO.	COMPANY	GROWTH	G*115%	G*125%	G*150%	AS FILED MODEL RESULT	MODEL RESULT 115% G	MODEL RESULT 125% G	MODEL RESULT 150% G
1	AGL Resources	3.57%	4.11%	4.46%	5.36%	8.6%	9.1%	9.5%	10.5%
2	Alliant Energy	6.35%	7.30%	7.94%	9.53%	10.8%	11.8%	12.5%	14.1%
3	Amer. Elec. Power	3.53%	4.06%	4.41%	5.30%	8.8%	9.3%	9.7%	10.7%
4	Atmos Energy	4.37%	5.03%	5.46%	6.56%	9.0%	9.7%	10.2%	11.3%
5	Consol. Edison	3.15%	3.62%	3.94%	4.73%	7.5%	8.0%	8.3%	9.2%
6	DTE Energy	4.29%	4.93%	5.36%	6.44%	8.9%	9.5%	10.0%	11.1%
7	G't Plains Energy	9.75%	11.21%	12.19%	14.63%	14.6%	16.2%	17.2%	19.8%
8	Northeast Utilities	6.06%	6.97%	7.58%	9.09%	9.4%	10.4%	11.0%	12.6%
9	Northwest Nat. Gas	3.25%	3.74%	4.06%	4.88%	7.4%	7.9%	8.2%	9.1%
10	Piedmont Natural Gas	4.55%	5.23%	5.69%	6.83%	8.7%	9.4%	9.9%	11.1%
11	Pinnacle West Capital	6.22%	7.15%	7.78%	9.33%	11.1%	12.1%	12.8%	14.4%
12	Portland General	4.13%	4.75%	5.16%	6.20%	8.7%	9.3%	9.8%	10.9%
13	Southern Co.	5.58%	6.42%	6.98%	8.37%	10.2%	11.1%	11.7%	13.2%
14	TECO Energy	4.11%	4.73%	5.14%	6.17%	9.4%	10.1%	10.5%	11.6%
15	Vectren Corp.	5.00%	5.75%	6.25%	7.50%	10.2%	11.0%	11.6%	12.9%
16	Westar Energy	5.80%	6.67%	7.25%	8.70%	10.9%	11.8%	12.4%	14.0%
17	WGL Holdings Inc.	4.60%	5.29%	5.75%	6.90%	8.8%	9.6%	10.0%	11.3%
18	Wisconsin Energy	5.35%	6.15%	6.69%	8.03%	8.6%	9.5%	10.0%	11.4%
19	Xcel Energy Inc.	5.27%	6.06%	6.59%	7.91%	9.5%	10.3%	10.9%	12.3%
20	Average					9.5%	10.3%	10.9%	12.2%

87.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide

Exhibit B1-9-6, Appendix G, p. 28

Comparable Risk Utilities

Dr. Vander Weide states on page 28 that he uses the I/B/E/S growth estimates because they "…(1) are widely circulated in the financial community, (2) include the projections of multiple reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors."

87.1 Please describe in more detail how the IBES forecasts are determined, specifically:

(a) When were the analysts' forecasts used by Dr. Vander Weide prepared?

Response:

Dr. Vander Weide's studies use data through May 31, 2012, and the analysts' forecasts used by Dr. Vander Weide in his cost of equity studies were provided by the analysts' at mid-May 2012.

(b) Was there any screening of the analysts whose forecasts were used for each of the companies in the samples, by either I/B/E/S or by Dr. Vander Weide?

Response:

Dr. Vander Weide does not screen the analysts whose forecasts contribute to the mean forecast; he uses the mean growth forecasts provided by the I/B/E/S database. As discussed in Answer 75, page 28 of his written evidence, I/B/E/S reports the analysts' EPS growth forecasts and provides the mean and standard deviation of the forecasts received for each firm. To the best of his knowledge, I/B/E/S simply reports the mean and standard deviation of the forecasts they receive from analysts.

(c) Was the growth rate used provided directly by the analysts' forecasts or did Dr. Vander Weide calculate the growth rate from other data in the forecasts, such as target price or dividend forecast? If so, how was the calculation done?

Response:

Dr. Vander Weide uses the mean of the analysts' forecasts as reported by I/B/E/S. Dr. Vander Weide does not calculate the mean, nor does he perform any other calculations regarding the mean forecast.

88.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide

Exhibit B1-9-6, Appendix G, p. 42 and Exhibit 14

Comparable Risk Utilities

On page 42, Dr. Vander Weide states that “…the average Value Line utility beta at the time of my studies is 0.73, whereas the historical ratio of the average utility risk premium to the average S&P 500 risk premium is 0.92 (5.21 ÷ 5.67 = 0.92) (see Exhibit 13). “

88.1 Can Dr. Vander Weide confirm that his calculation of the historical risk premium ratio is actually shown in Exhibit 14?

Response:

Confirmed.

88.2 Please describe in more detail how the Value Line utility beta is calculated, including what set of utilities it uses and the time period over which it is calculated? Is the historical risk premium ratio as calculated by Dr. Vander Weide the same as a beta value? If not, please explain how the two differ.

Response:

Value Line calculates a utility beta for each utility company that it covers. Value Line describes its beta calculation as follows:

> The beta coefficient is derived from a least-squares regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The betas are adjusted for their long-term tendency to converge toward 1.00.

Yes, Dr. Vander Weide’s historical risk premium ratio is the same as a beta value. However, this beta value is calculated differently than the Value Line beta. Specifically, Dr. Vander Weide begins with the basic CAPM equation, described in Answer 119, page 41, of his written evidence:

$$ER_i = R_f + \beta_i \left\lfloor ER_m - R_f \right\rfloor,$$

Where ER_i is the expected return on security or portfolio *i*, R_f is the risk-free rate, $ER_m - R_f$ is the expected risk premium on the market portfolio, and β_i is a measure of the risk of investing in security or portfolio *i*.

Dr. Vander Weide solves the basic CAPM equation for β_i, obtaining:

$$\beta_i = (ER_i - R_f) \div (ER_m - R_f)$$

Dr. Vander Weide then uses the average historical risk premium on the S&P Utilities as his estimate of $ER_i - R_f$ and the long-run average risk premium on the market (S&P 500) as his estimate of $ER_m - R_f$. Finally, Dr. Vander Weide estimates beta by dividing his estimate of the risk premium on the S&P Utilities by his estimate of the risk premium on the S&P 500.

88.3 In previous testimony, how many times has Dr. Vander Weide used the Value Line utility beta to calculate the required rate of return for a utility? How many times has he discarded it in favour of a historical risk premium ratio calculated as shown in Exhibit 14?

Response:

Since Dr. Vander Weide does not maintain records on his recommendations in the proceedings in which he presents expert testimony, he is unable to count the number of times he has used Value Line utility betas to calculate the required rate of return for a utility. However, as a general rule, Dr. Vander Weide recognizes that the CAPM underestimates the cost of equity for companies with betas significantly less than 1.0. Therefore, he gives little weight to CAPM calculations for utilities with betas that are significantly less than 1.0. In recent years, Dr. Vander Weide has also recognized that the average Value Line utility beta frequently understates the beta derived from the historical risk premium ratio calculated as shown in Exhibit 14.

88.4 If Dr. Vander Weide has calculated a utility risk premium ratio previously using the general method shown in Exhibit 14, has he used the time period and the same data sets? If not, how does this calculation differ from those previous calculations?

Response:

Dr. Vander Weide has previously begun with the same time period and data sets, but extends his data set for another year when additional data become available. There is no change in his methodology.

88.5 Granted that the historical ratio of the average utility risk premium to the average S&P 500 risk premium is 0.92, does Dr. Vander Weide believe that, on a common sense basis, utilities are about as risky as the average of the market? Why or why not?

Response:

As he discusses in response to Answer 124, pp. 43 -44, Dr. Vander Weide's evidence that the historical 0.92 ratio of the average utility risk premium to the average S&P 500 risk premium is consistent with one or both of two conclusions: (1) actual utility betas are significantly higher than published historical betas; or (2) the CAPM fails to explain actual utility returns in the marketplace. Dr. Vander Weide believes, on a common sense basis, that both conclusions are true.

88.5.1 In Dr. Vander Weide's opinion, which companies in the market would share the same risk as Canadian LDCs with monopoly service territories and deferral accounts for most cost and revenue fluctuations that are beyond the direct control of the LDCs?

Response:

Dr. Vander Weide's comparable groups of U.S. natural gas and electric companies also have "monopoly service territories" and cost adjustment mechanisms "for most cost and revenue fluctuations that are beyond the direct control of the company". Thus, in Dr. Vander Weide's opinion, his groups of natural gas and electric utilities are similar in risk to the Canadian LDCs.

89.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide

Exhibit B1-9-6, Appendix G, p. 43 and Exhibit 15

Comparable Risk Utilities

On page 43, Dr. Vander Weide states that "…the results for Canadian utilities are similar to the results for U.S. utilities in the sense that the average historical risk premiums on Canadian utility stocks are higher than would be indicated by the betas for Canadian utility stocks."

89.1 Please calculate the historical risk premium ratio for Canadian utilities using the method in Exhibit 14 and the data in Exhibit 15 (for both the S&P/TSX Canadian Utilities Index and the BMO Capital Markets Utility Group.

Response:

The historical risk premium ratio using the S&P/TSX Canadian Utilities Index is 1.46 (4.66 ÷ 3.20 = 1.46). The historical risk premium ratio using the BMO Capital Markets Utility Group is 2.61 (8.77 ÷ 3.36 = 2.61).

90.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide

Exhibit B1-9-6, Appendix G, p. 46, Table 4

Comparable Risk Utilities

Table 4 on page 46 provides the deemed equity ratios for Canadian Utilities.

90.1 Please provide a supplementary table showing the date applicable to the deemed equity ratio for each company and the corresponding allowed ROE at that time.

Response:

COMPANY	DEEMED EQUITY RATIO	ROE	DECISION	DATE
AltaGas	43.0%	8.75%	Decision 2011-474	Dec-11
ATCO Electric Disco	39.0%	8.75%	Decision 2011-474	Dec-11
ATCO Gas	39.0%	8.75%	Decision 2011-474	Dec-11
Enbridge Gas	36.0%	9.42%	EB-2009-0084	11-Dec-09
ENMAX Disco	41.0%	8.75%	Decision 2011-474	Dec-11
EPCOR Disco	41.0%	8.75%	Decision 2011-474	Dec-11
FortisAlberta	41.0%	8.75%	Decision 2011-474	Dec-11
Terasen (FortisBC Energy)	40.0%	9.50%	G-158-09	Dec-09
Gaz Métro	38.5%	8.90%	D-2011-182, R-3752-2011 Phase 2, 2011 11 25	Nov-11
Gazifère	40.0%	8.29%	D-2010-147, D-2011-829	Nov. 2010, Dec. 2011
Heritage Gas Ltd.	45.0%	11.00%	NSUARB-NG-HG-R-11 2011 NSUAR 183	Nov. 24, 2011
Newfoundland Power	45.0%	8.80%	ORDER NO. P.U. 17(2012)	15-Jun-12
Nova Scotia Power	40.0%	9.20%	NSUARB-NSPI-P-902 NSPI-P-202 2011 NSUARB 184	Nov-11
Pacific Northern Gas	40% - 45%	9.9% - 10.15%	G-158-09, G-84-10	Dec. 2009, May 2010
Union	36.0%	9.58%	EB-2009-0084	11-Dec-09

90.2 Please add a column to table 4 to indicate which of the utilities are being regulated under Performance Based Regulation (PBR) and the duration of their PBR.

Response:

The information is included in the table below.

Company	Performance Based Regulation	PBR Duration
AltaGas	Yes	2013 -2017
ATCO Electric Disco	Yes	2013-2017
ATCO Gas	Yes	2013-2017
Enbridge Gas	Yes	2008-2012
ENMAX Disco	Yes	2007-2013
EPCOR Disco	Yes	2013-2017
FortisAlberta	Yes	2013-2017
Gaz Metro	Yes	2007-2012
Gaziféreh	Yes	2006-2015
Heritage Gas Ltd.	No	N/A
Newfoundland Power	No	N/A
Nova Scotia Power	No	N/A
Pacific Northern Gas	No	N/A
Terasen (FortisBC Energy)	No	N/A
Union	Yes	2008-2012

91.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide

Exhibit B1-9-6, Appendix G, p. 46

Comparable Risk Utilities

On page 46, Dr. Vander Weide states that "I present evidence on market value equity ratios as well as book value equity ratios because financial risk depends on the market value percentages of debt and equity in a company's capital structure rather than on the book value percentages of debt and equity in the company's capital structure."

91.1 With the data on market and book values for your samples of U.S. utilities, please provide the average market-to-book ratios for the samples.

Response:

Dr. Vander Weide provides evidence In Exhibit 20 and Exhibit 21 on the market value equity ratios for the publicly-traded utilities in his comparable U.S. utility groups. He provides evidence on allowed equity ratios for utility subsidiaries in decisions made since January 1, 2010, through June 30, 2012. However, Dr. Vander Weide does not present evidence on the book value equity ratios of the publicly-traded utilities in his comparable utility groups. Thus, it is not possible to calculate market-to-book ratios from the data provided in Dr. Vander Weide's written evidence. Nonetheless, the market-to-book ratios for the publicly-traded companies in Dr. Vander Weide's comparable utility groups are shown in the following tables.

Table 3
Market-to-Book Ratios for Exhibit 6 Comprehensive Group of U.S. Utilities

LINE NO.	COMPANY	MARCH - MAY 2012 AVE. STOCK PRICE	2011 YEAR-END BOOK VALUE PER SHARE	PRICE TO BOOK VALUE
1	AGL Resources	38.82	28.33	1.37
2	Alliant Energy	43.65	27.14	1.61
3	Amer. Elec. Power	38.18	30.33	1.26
4	Atmos Energy	31.91	24.98	1.28
5	CenterPoint Energy	19.63	9.91	1.98
6	CMS Energy Corp.	22.25	11.92	1.87
7	Consol. Edison	58.67	39.05	1.50
8	Dominion Resources	51.34	20.08	2.56
9	DTE Energy	55.49	41.41	1.34
10	Duke Energy	21.20	17.05	1.24
11	FirstEnergy Corp.	46.10	31.75	1.45
12	G't Plains Energy	19.98	21.74	0.92
13	Hawaiian Elec.	25.94	15.95	1.63
14	NextEra Energy	62.51	35.92	1.74
15	NiSource Inc.	24.39	17.63	1.38
16	Northeast Utilities	36.39	22.65	1.61
17	Northwest Nat. Gas	45.41	26.08	1.74
18	Pepco Holdings	18.86	18.79	1.00
19	Piedmont Natural Gas	30.66	13.78	2.22
20	Pinnacle West Capital	47.65	34.98	1.36
21	PNM Resources	18.42	19.62	0.94
22	Portland General	25.03	22.07	1.13
23	Public Serv. Enterprise	30.58	20.30	1.51
24	SCANA Corp.	45.33	29.92	1.52
25	Sempra Energy	61.93	41.00	1.51
26	Southern Co.	45.11	20.32	2.22
27	TECO Energy	17.63	10.50	1.68
28	Vectren Corp.	29.02	17.89	1.62
29	Westar Energy	27.86	22.03	1.26
30	WGL Holdings Inc.	40.02	23.49	1.70
31	Wisconsin Energy	35.76	17.19	2.08
32	Xcel Energy Inc.	26.84	17.43	1.54
33	Average			1.56

Table 4
Market-to-Book Ratios for Exhibit 7 Smaller Group of U.S. Utilities

LINE NO.	COMPANY	MARCH - MAY 2012 AVE. STOCK PRICE	2011 YEAR-END BOOK VALUE PER SHARE	PRICE TO BOOK VALUE
1	AGL Resources	38.82	28.33	1.37
2	Alliant Energy	43.65	27.14	1.61
3	Amer. Elec. Power	38.18	30.33	1.26
4	Atmos Energy	31.91	24.98	1.28
5	Consol. Edison	58.67	39.05	1.50
6	DTE Energy	55.49	41.41	1.34
7	G't Plains Energy	19.98	21.74	0.92
8	Northeast Utilities	36.39	22.65	1.61
9	Northwest Nat. Gas	45.41	26.08	1.74
10	Piedmont Natural Gas	30.66	13.78	2.22
11	Pinnacle West Capital	47.65	34.98	1.36
12	Portland General	25.03	22.07	1.13
13	Southern Co.	45.11	20.32	2.22
14	TECO Energy	17.63	10.50	1.68
15	Vectren Corp.	29.02	17.89	1.62
16	Westar Energy	27.86	22.03	1.26
17	WGL Holdings Inc.	40.02	23.49	1.70
18	Wisconsin Energy	35.76	17.19	2.08
19	Xcel Energy Inc.	26.84	17.43	1.54
20	Average			1.55

92.0 Reference: Testimony on Cost of Capital for the FBCU by Dr. Vander Weide

Exhibit B1-9-6, Appendix G, p. 116, Exhibit 23

Comparable Risk Utilities

On page 116, in Exhibit 23 of Dr. Vander Weide's evidence, Dr. Vander Weide states that researchers at State Street Financial Advisors updated his study using data through year-end 2003.

92.1 Please provide a copy of the updated study.

<u>Response:</u>

Attachment 92.1 contains a copy of the updated study.

93.0 Reference: Testimony by Dr. Vander Weide and Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix G, p. 24; and Appendix I

Comparable Risk Utilities

Dr. Vander Weide quotes on page 24 of his testimony, from the Ontario Energy Board's "Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. That quote states in part that

> "In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed."

93.1 Can Concentric confirm that it is the firm referred to in the following quote from the OEB Report?

> "The Board notes that Concentric did not rely on the entire universe of U.S. utilities for its comparative analysis. Rather, Concentric carefully selected comparable companies based on a series of transparent financial metrics, and the Board is of the view that this approach has considerable merit. Commenting on Concentric's analysis, Union Gas noted that no one else in the consultation performed this kind of detailed analysis of U.S. comparators. The use of a principled, analytical, and transparent approach to determine a low risk comparator group from a riskier universe for the purpose of informing the Board's judgment was supported by various participants in the consultation." (OEB Report of the Board on the cost of Capital for Ontario's Regulated Utilities, p. 22)

Response:

Confirmed.

93.1.1 If so, can Concentric provide a description of the "…series of transparent financial metrics" that the OEB refers to in its report?

Response:

Concentric selected its gas and electric utility proxy groups based upon screening criteria, to assemble a group of like risk companies. The screening criteria employed were as follows:

1. Begin with the universe of Value Line natural gas or electric distribution companies, depending on whether the proxy group is being selected for an electric utility or a gas utility;

2. All are currently publicly traded and paying dividends as recent market data must be available to calculate the DCF and CAPM;

3. Utilities with S&P credit ratings (include all utilities with credit rating the same or higher than the target company or companies);

4. Utilities with greater than 60 percent regulated operations, as measured by the percentage of regulated utility revenue to total consolidated revenue for 2006 through 2008;

5. At least 60 percent of regulated revenue was derived from either natural gas or electricity distribution operations for 2006 through 2008, depending on whether the proxy group is being selected for an electric utility or a natural gas utility; and lastly

6. Excluded any utility that is currently the target of an acquisition or merger since the stock price may not be representative of its underlying utility operations.

Concentric also examined the relative risk profiles of the Ontario and proxy group utilities on a variety of operating and financial performance metrics, to assess the relative risk profiles of the groups compared to that of the subject company. To that end, Concentric reviewed the following risk metrics:

Operating Risk Profile:

1. Credit rating(though primarily financial, does take into account certain operating characteristics that may affect the utility's ability to meet debt commitments);
2. Regulated revenues (for a measure of scale);
3. Number of distribution customers (to provide another measure of scale);
4. Percent industrial revenue to total revenue (to assess the level of risk associated with potential large fluctuations in load due to fuel switching, bypass, or business closures);
5. Net property, plant and equipment (as another measure of size of the company);
6. Percent FFO to CapEx (reflecting the company's ability to meet its current levels of capital expenditures);

7. The competitive market environment the utility operates in;
8. Authorized return; and
9. Equity Ratio.

Financial Risk Profile:

1. Revenue;
2. Embedded Debt Cost;
3. Actual Debt / Capital Ratio;
4. EBIT Interest Coverage Ratio;
5. FFO / Interest Coverage; and
6. FFO / Debt.

Regulatory Risk Profile:

1. Volume Variability Protection (Weather Normalization, Revenue Decoupling, Straight Fixed Variable Rate Design, Tiered Rates, etc.);
2. Fuel and Purchased Power Cost Adjustment Mechanisms (Purchased Gas Adjustment, Fuel Cost Pass Through, Timeliness of Recovery);
3. Ratemaking mechanisms to address regulatory lag (Forward Test Year, Forecasted Test Year, Adjusted Historic Test Year, Special Purpose Rate Proceedings, Other);
4. Ratemaking mechanisms that promote financial stability (Allowed ROE, Equity Ratio, Earnings Sharing Mechanisms, Ring Fencing);
5. Ratemaking mechanisms to address escalating costs (O&M Tracker, Inflation Adjustments);
6. Major Cost recovery (CWIP in Rate Base, Preapproval of Construction Costs, Cost Trackers); and
7. Other Cost recovery (Cost Recovery of minor costs and expenses through deferral accounts, riders and cost trackers).

94.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, pp. 2-3

Generic Business Risk Categories and Factors

FBCU states that "Ms. McShane has described in her evidence categories of utility business risk that can be applied to utilities generally, which are repeated below for ease of reference: Market/Demand risk, Competitive risk, Supply risk, Operating Risk, Political risk, Regulatory risk."

Table 1. Business Risk Categories and Risk Factors Addressed in this Appendix

Business Risk Category	Risk Factors
Business Profile	• Type of utility • Energy product offering • Size of utility • Service area • Customer profile
Economic Conditions	• GDP • Housing starts • Unemployment
Energy Price	• Commodity price • Commodity price volatility • Upfront and installation costs
Market Shifts	• New technology and energy forms • Perception of energy • Housing types • Changes in energy use • Changes in customer additions
Energy Supply	• Availability of supply • Security of supply
Operating	• Infrastructure integrity • Third party damages • Unexpected events
Political	• Energy policies and legislation • GHG emissions reductions • Carbon tax • Aboriginal rights
Regulatory	• Regulatory approvals • Regulatory uncertainty and lag • Deferral accounts • Administrative penalties

94.1 Please discuss the applicability of each of the eight business risk categories and 29 risk factors, included in Table 1 (page 3) reproduced above, to FEI/FAES's regulated TES projects such as Delta School District No. 37 (DSD), Tsawwassen Springs Development, and PCI Marine Gateway that have had their business risks assessed on a case by case basis to determine their respective cost of capital.

Response:

The FBCU respectfully submit that BCUC IRs 1.94.1 through 1.94.3.2 are out of scope. The FBCU understand that the purpose of the first Phase of this GCOC is to identify the benchmark, assess its characteristics and make a determination on the fair return for the benchmark. The Commission made clear in Order No. G-72-12, p.8 that there is some latitude to review the characteristics of other Affected Utilities, but the relevance of that information in Phase I arises because the Commission Panel "has not yet defined the low risk benchmark utility":

PNG submits that it should not be required to file the documents referred to in the Company-Related Documents section in the MFR document because the material is not considered by PNG to be relevant to the determination of the ROE and capital structure for a benchmark utility. The Commission Panel disagrees. The Commission Panel has not yet defined the low-risk benchmark utility for which to determine rates. In the Commission Panel's view, the characteristics of all the utilities comprising each Affected

Utility in B.C., as well as information pertaining to their respective operating environment, will serve as reference points and are relevant and required at this time.

FAES and its TES projects are not Affected Utilities, and there is no realistic prospect that FAES or a TES project such as Tsawwassen Springs, PCI Marine Gateway or Delta School District will serve as the benchmark utility. The information sought in BCUC IR 1.94.1 through 1.94.3.2 is only relevant in defining the risk premium for TES projects, which the Commission has determined will be the subject matter of either another Phase of this proceeding or a separate proceeding. The FBCU will require an opportunity to present comprehensive evidence on those matters, and the FBCU respectfully submit that it is more appropriate to address these questions to FBCU once the FBCU have had the opportunity to do so.

Ms. McShane defines "Market/Demand risk" as: "Market demand risks relate to the size of the market for the utility's services and the ability of the utility to capture market share. Market demand risks reflect the demographics of the service area, including the diversity of the economy, economic growth potential, geography/weather, customer concentration, customer spending patterns, customer mix, and customer preferences."

94.2 Given this definition, how would the FBCU assess the market demand risk for each of the following TES projects, on an individual basis: DSD, Tsawwassen Springs Development and PCI Marine Gateway?

Response:

Please refer to the response to BCUC IR 1.94.1.

94.2.1 For each of these three projects, if the FBCU believe that market demand risk is present, please explain why.

Response:

Please refer to the response to BCUC IR 1.94.1.

Ms. McShane defines "Competitive risk" as: "Competitive risk refers to the business risk arising from competition for customers and load due to the existence of alternatives to, or potential for substitutes for, the utility's services. Competitive risks would include a utility's cost structure; e.g., a high cost structure has the potential to lead to customer and load attrition and to the development of lower cost alternatives."

94.3 Given this definition, how would the FBCU assess the competitive risk for each of the following TES projects on an individual basis: DSD, Tsawwassen Springs Development and PCI Marine Gateway?

Response:

Please refer to the response to BCUC IR 1.94.1.

94.3.1 For each of these three projects, if the FBCU believe that competitive risk is present, please explain why.

Response:

Please refer to the response to BCUC IR 1.94.1.

94.3.2 Once FEI has succeeded in negotiating long-term contracts with TES customers (e.g., DSD, Tsawwassen Springs Development, PCI Marine Gateway), would the FBCU agree that these customers are captive with no energy supply alternatives for the duration of the long-term contract, therefore eliminating competition risk altogether?

Response:

Please refer to the response to BCUC IR 1.94.1.

The FBCU have identified generic risk factors applicable to each category or sub-category of business risk in Table 1 (page 4). In Table 2 (page 5), the FBCU have ranked the business risk categories as they apply to FEI and provided a summary assessment of whether the risk to FEI associated with particular risk factors is higher/lower/same as in 2009.

94.4 Please explain why FBCU have not ranked the two business risk categories "Business Profile" and "Economic Conditions" that are included in Table 1, along with their risk factors. Please also provide the risk status since 2009 and the ranking of those risks.

Response:

The business profile section is an overview of FEI's business and its overall risk profile, which is impacted and or influenced by all the other risk factor categories that follow. The economic conditions section was intended to provide a high-level overview of economic conditions in context of FEI's business. Rather than considering it as a risk factor in its own right, the FBCU considered it to be influencing the risk factor "market/demand risk".

95.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H

Net Income

95.1 For each of the last 10 years, please provide a table of FEI's awarded ROE (%) and net income from utility operations as approved by BCUC ($), along with the actual achieved ROE and net income from utility operations.

Response:

Please see the following table.

	ROE				Utility Net Income ($000s)				
	Allowed[1] (a)	Actual Pre-ESM (b)	Actual Post-ESM[2] (c)		Allowed[1] (d)	Actual Pre-ESM (e)	Actual Post-ESM[2] (f)	Variance[3] (g)	% Variance (h)
2002	N/A	9.73%	N/A		N/A	70,980	N/A	N/A	N/A
2003	9.42%	10.23%	N/A		70,584	75,914	N/A	5,330	7.6%
2004	9.15%	9.34%	9.25%		69,460	71,125	69,946	486	0.7%
2005	9.03%	10.78%	9.91%		71,399	85,697	78,728	7,329	10.3%
2006	8.80%	10.47%	9.64%		77,195	89,527	82,380	5,185	6.7%
2007	8.37%	10.73%	9.55%		72,502	91,112	81,094	8,592	11.9%
2008	8.62%	10.64%	9.63%		75,574	92,050	83,324	7,750	10.3%
2009	8.99%	11.89%	10.44%		79,984	102,419	89,935	9,951	12.4%
2010	9.50%	9.42%	N/A		96,305	95,115	N/A	(1,190)	-1.2%
2011	9.50%	10.15%	N/A		99,908	104,084	N/A	4,176	4.2%

Notes:

[1] N/A indicates that an approved revenue requirement did not exist for that year

[2] Post-ESM only applicable for the years when FEI was under PBR (2004 - 2009)

[3] Variance calculated as column (f) less column (d) in PBR years; or column (e) less column (d) in non-PBR years

95.1.1 Please explain any positive or negative variances between awarded and achieved net income from utility operations greater than 5 percent in any year.

Response:

As shown in the response to BCUC IR 1.95.1, in the year 2003, and in the PBR years of 2005 through 2009, net income from utility operations was 5 percent or more than awarded. During the PBR period, O&M and capital were set through a formula that was designed to result in savings that were then shared with customers, resulting in earnings that were above the earnings that were awarded by the Commission. An explanation for each of those years is provided below.

2003

O&M variance $5.2M and lower depreciation $0.7M, tax timing differences $0.4M; offset by lower revenue $1M primarily due to lower late payment charges/connection fees

2005

O&M variance due to use of formula for setting allowed O&M $6.3M, lower depreciation due to use of formula for setting allowed capital $1.8M and income tax timing differences $0.5M; offset by lower revenue $0.7M primarily due to use of formula for setting late payment charges/connection fees, and tax shield on CCA $0.6M

2006

O&M variance due to use of formula for setting allowed $5.7M and lower depreciation due to use of formula for setting allowed capital $1.7M; offset by lower revenue $1.4M due to lower volumes and use of formula for setting late payment charges/connection fees, and tax shield on CCA $0.7M

2007

O&M variance due to use of formula for setting allowed $6.6M and lower depreciation due to use of formula for setting allowed capital $4.8M; offset by lower revenue $1.8M due to lower volumes and use of formula for setting late payment charges/connection fees, and tax shield on CCA $1M

2008

O&M variance due to use of formula for setting allowed $4.7M and lower depreciation due to use of formula for setting allowed capital $4.6M; offset by lower revenue $0.5M due to use of formula for setting late payment charges/connection fees, and tax shield on CCA $1M

2009

O&M variance due to use of formula for setting allowed $3.9M and lower depreciation due to use of formula for setting allowed capital $3.5M and prior year tax adjustments $3.2M; offset by lower revenue $0.1M due to use of formula for setting late payment charges/connection fees, and tax shield on CCA $0.5M

95.1.2 During this period did the BCUC award any costs to FEI for imprudence? If so, please explain the circumstances and the impact to FEI's net income.

Response:

FEI assumes the question was intended to refer to a disallowance for imprudence. During this period, the BCUC did not order any costs to be removed from the cost of service as a result of imprudence. However, in Order No. G-98-05, the Commission did not approve the recovery of IPC development costs of $5.8 million pre-tax from ratepayers, and therefore that amount was expensed as a non-regulated cost in FEI (then Terasen Gas Inc.).

Although it pre-dated the period requested in the question, the acquisition of the Lower Mainland Gas Division assets from BC Hydro in 1988 resulted in a significant disallowance of approximately $177 million of costs that could not be included in rate base. These costs continue to be amortized over the life of the assets resulting in a reduction in earnings.

95.1.3 Did FEI make any applications to the BCUC during this period for exceptional circumstances and costs that FEI wished to be protected from outside of the annual rate setting? If so, please explain each application and the disposition by the BCUC.

Response:

Outside of the regular rate setting process, FEI applied for and received approval of a deferral account for the ABC T-project (Order No. G-27-02), and for the recovery of costs associated with the implementation of HST (Letter No. L-96-10). As discussed in response to BCUC IR 1.95.1.2, FEI applied for but was denied recovery of IPC costs.

Although part of the annual rate setting process, during the term of the PBR Period, FEI received special treatment for Exogenous Factors. Customers' rates were adjusted for those exogenous factors that were beyond the control of FEI including: judicial, legislative or administrative changes, orders and directions; catastrophic events, by-pass or other similar events imposed on FEI which were not reflected in the 2003 base upon which subsequent year's rates were set. Also included in Exogenous Factors were changes in Generally Accepted Accounting Principles, standards and policies. Changes in revenue requirements resulting from directions from the Commission were also to be treated as Exogenous Factors.

FEI applied for and received Exogenous Factor treatment during the years 2004 to 2009 for:

Government Policy Changes and Legislative Changes

- Ontario Securities Commission Compliance Costs
- PST Reassessment re Southern Crossing Pipeline
- Carbon Tax Implementation
- Olympic Security Costs
- Unforecast annual changes to income tax rates
- Changes resulting from directions of the Commission
- BCUC Levies

GAAP Changes

- Accounting Guideline AcG 15 Consolidation of Variable Interest Entities
- Inventories
- IFRS Implementation Costs

95.1.4 Based on this information, please comment on FEI's perception of its overall risk to net income from regulatory operations in BC.

Response:

Whether the concept of exogenous factors is explicitly defined in a rate setting agreement, the utility always has the opportunity to apply to the Commission for relief from items of an uncontrollable nature. Whether through an exogenous factor within an existing agreement or a separate application, there is a risk that items for which FEI seeks recovery in this manner, or items that go through the regular revenue requirements review, will be denied recovery. The existence and the use of these mechanisms is appropriately reflected in the allowed ROE awarded to the Company.

An embedded mechanism (like exogenous factor treatment) tends to reduce uncertainty on costs that are outside of FEI's management control. During the PBR period, this enabled FEI and its management team to focus on realizing cost reductions that were within management's control with the savings shared with its customers.

The availability of these exogenous factor-type mechanisms provide an appropriate means to allow the utility to recover its prudently incurred cost of service, by allowing for recovery of costs that are beyond management's control. They do not, however, reduce the risk associated with those items where the utility has some degree of control; neither do they guarantee the recovery of costs. Therefore, they have a limited impact on the overall risk to net income.

96.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H

Revenue Requirement Risk

96.1 Please provide a one page summary table of FEI's awarded 2011 revenue requirement by major cost categories and expected revenue by customer class. At minimum, the cost of service categories should include:

a) Cost of gas

b) Operations and maintenance expenses

c) Depreciation and amortization expenses

d) Other revenue

e) Taxes

f) Financing costs

g) ROE

h) Margin revenue by customer class (residential, commercial, industrial, other)

Response:

FEI interprets the term "awarded 2011 revenue requirement" to mean the 2011 revenue requirement which underpinned the delivery rates determined by FEI's 2010-2011 Revenue Requirements Application as approved by BCUC Order G-141-09 and BCUC Order G-158-09. Please refer to the summary table below.

	FEI 2011 Approved Revenue Requirements	$ Thousands
1	Cost of Gas	$ 989,627
2	Operations and Maintenance Expenses	$ 184,625
3	Property and Sundry Taxes	$ 50,211
4	Depreciation and Amortization Expenses (incl. Removal Provision)	$ 99,878
5	Other Operating Revenue	$ (24,394)
6	Income Taxes	$ 32,516
7	Other Expenses (NSP Provision)	$ 1,025
8	Financing Costs	$ 108,504
9	ROE	$ 99,909
10	Total Revenue (sum of rows 1 through 9)	$ 1,541,901
11	Margin Revenue (sum of rows 2 through 9)	$ 552,274
	Margin Revenue by Customer Class	
12	Residential	$ 331,183
13	Commercial	$ 154,247
14	Industrial	$ 66,844
15	Total Margin Revenue (same as row 11)	$ 552,274

96.1.1 For each cost and revenue category, please identify the cost or revenue and any risk mitigation features allowed by BCUC such as RSAM, cost of gas deferral and incentive, interest rate deferral, net income sharing, etc. Please identify what percentage of the cost or revenue for each category is covered by the risk mitigation feature.

Response:

This response also addresses BCUC IR 1.96.1.2.

As discussed in Appendix H, the existence of deferral accounts has not significantly changed the overall business risk of FEI over time. As described in Section 10.3 of the Application (Appendix H), approved deferral accounts have reduced the short-term earnings volatility, but not the long-term risks. The majority of deferral accounts have been put in place to ensure forecast variances do not result in costs being inappropriately borne by customers or by the companies, and are mainly used to mitigate the rate impacts and rate volatility for customers.

Please refer to the tables below which include the FEI cost and revenue categories and the percentage of revenues/costs covered by deferral accounts.

Table 1: FEI Cost Categories and Deferral Accounts

2011 FEI Approved Revenue Requirement

	Revenue Requirement Item	Revenue Requirement			Revenue Requirement Covered by Deferrals			
		$000's	% of Revenue Requirement[1]	% of Delivery Margin[2]	($000's)[3]	% of Category[4]	% of Revenue Requirement[5]	% of Delivery Margin[6]
Line	Particular	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Cost of Gas	$ 989,627	64.2%	N/A	$ 989,627	100.0%	64.2%	N/A
2	Operation & Maintenance Expenses	184,625	12.0%	33.4%	16,741	9.1%	1.1%	3.0%
3	Property and Sundry Taxes	50,211	3.3%	9.1%	50,211	100.0%	3.3%	9.1%
4	Depreciation and Amortization Expenses (incl. Removal Provision)[7]	99,878	6.5%	18.1%	-	0.0%	0.0%	0.0%
5	Other Operating Revenue	(24,394)	-1.6%	-4.4%	(2,400)	9.8%	-0.2%	-0.4%
6	Income Taxes[8]	32,516	2.1%	5.9%	-	0.0%	0.0%	0.0%
7	Other Expenses (NSP Provision)	1,025	0.1%	0.2%	-	0.0%	0.0%	0.0%
8	Financing Costs	108,504	7.0%	19.6%	106,577	98.2%	6.9%	19.3%
9	ROE	99,909	6.5%	18.1%	-	0.0%	0.0%	0.0%
10	**Total Revenue Requirement**	**1,541,901**	**100.0%**	**100.0%**	**1,160,756**		**75.3%**	**31.0%**
11	**Total Delivery Margin Revenue Requirement**	**552,274**			**171,129**			

Notes:

1 Category amount in column 1 divided by total (line 10) of column 1
2 Category amount in column 1 divided by total (line 11) of column 1
3 Amounts reflect the 2011 forecast amortization
4 Amounts covered by deferrals: in O&M pertaining to OPEB, pension, insurance, BCUC levies; SCP mitigation other revenue; long term debt expense account
5 Column 4 divided by Line 10, Column 1
6 Column 4 divided by Line 11, Column 1
7 Deferral on depreciation expense variance was not in place in 2011. Amortization expense reflects previous years and as such is not applicable for this analysis.
8 Income tax variations due to changes in regulation are captured in the Income Tax Variance deferral

Table 2: FEI Revenue Categories and Deferral Accounts

Delivery Margin Revenue by Customer Class	Delivery Margin Revenue $000's	% of Total
Residential[1]	$ 331,183	60.0%
Commercial[1]	154,247	27.9%
Industrial	66,844	12.1%
Total Delivery Margin Revenue Requirement	**552,274**	**100.0%**

[1]Residential and Commerical revenues are protected for use rate changes through the RSAM mechanism but are not protected for differences in actual and forecasted customers. FEI is unable to quantify the % of revenue covered by the RSAM on an approved basis.

Please refer to the table below for an overall assessment of the risk to each cost and revenue category based on the percentage of the category covered by deferral accounts. FEI's historic variance between actual and awarded costs and sales are not an indication of riskiness, but rather reflect FEI's continued focus on managing the costs and revenues that can be controlled. Further, when the 11 years in which FEI was under performance based regulation are excluded, the cumulative variance between FEI's achieved return and allowed return on equity from 1994 to 2011 is minimal at approximately 2 per cent.[5] Thus, the overall risk assessment is not affected by the historic variance between actual and awarded costs and sales.

Table 3: Risk Assessment Based on Deferral Account Coverage

Revenue Requirement Item	Deferral Account	Overall Risk Assessment Based on Deferral Accounts	Explanation
Cost of Gas	• Commodity Cost Reconciliation Account (CCRA) • Midstream Cost Reconciliation Account (MCRA) • Revelstoke Propane Cost Deferral Account	Low	With 100% of the category covered by the noted deferral accounts, FEI has rated this category as low
Operation & Maintenance Expenses	• Pension & OPEB Variance Deferral • Insurance Variance Deferral • BCUC Levies Variance Deferral	High	With approximately 9% of the category covered by the noted deferral accounts, FEI has rated this category as high
Property and Sundry Taxes	• Property Tax Deferral	Low	With 100% of the category covered by the noted deferral account, FEI has rated this category as low
Depreciation and Amortization Expenses (incl. Removal Provision)	• Actual amortization of deferrals are set to equal the approved amounts	High	With 0% percent of this category covered by deferral accounts in 2011, FEI has rated this category as high. Please refer to note 7 of table 1 above

[5] Please refer to BC Util Cust-FBCU IR 1.2.4, the sum of column (e) for the years 1994 through 1997, 2003 and 2010-2011 as compared to the sum of column (h) for those same years.

Revenue Requirement Item	Deferral Account	Overall Risk Assessment Based on Deferral Accounts	Explanation
Other Operating Revenue	• SCP Mitigation Revenues Variance Deferral Account	High	With approximately 10% of the category covered by the noted deferral account, FEI has rated this category as high
Income Taxes	• Tax Rate Variance Account	Moderate	Although a percentage cannot be quantified in table 1, FEI has rated as moderate to reflect that the deferral account will capture tax rate changes
Other Expenses (NSP Provision)		Low	Although a percentage cannot be quantified in table 1, FEI has rated as low to reflect that generally items do not exist in this category and if so are likely flow through in nature
Financing Costs	• Interest Variance Deferral	Low	With approximately 98.2% of this category covered by a deferral account, FEI has rated as low. Please note that variances in the actual debt level on the short-term debt are not covered by the deferral.
Revenue			
Residential	• Revenue Stabilization Adjustment Mechanism	Moderate	FEI has rated as moderate because the RSAM captures variances in use per customer and does not capture variances in customer additions. Please see paragraph below for further discussion on the RSAM account.
Commercial	• Revenue Stabilization Adjustment Mechanism	Moderate	FEI has rated as moderate because the RSAM captures variances in use per customer and does not capture variances in customer additions. Please see paragraph below for further discussion on the RSAM account.
Industrial		High	As there are no deferral accounts pertaining to industrial customers, FEI has rated this category as high

Please also refer to Exhibit B-1-9-6, Appendix H, Section 3 for a discussion on the overall risk assessment associated with Residential, Commercial and Industrial sales. Although the Residential and Commercial customer groups are covered for variances in use per customer by the Revenue Stabilization Adjustment Mechanism (RSAM), this account provides short term risk mitigation and it does not provide for recovery of the return on, or of, capital in the longer-term. Further, the RSAM does not reduce risks associated with longer-term reductions in consumption, which longer-term risks are a significant aspect of the Company's business risk.

96.1.2 Please provide an overall assessment of the risk to each cost and revenue category based on the risk mitigation features and FEI's historic variance between awarded and actual costs and sales.

Response:

Please refer to the response to BCUC IR 1.96.1.1.

97.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, pp. 5-6

Commodity Risk

On page 5, FEI provides a snapshot of its business risks and concludes on page 6 that "Considered together, FEI business risk and regulatory risk is best characterized as being similar - no lower, and perhaps somewhat higher- than what it was in 2009."

97.1 Would FEI agree that the large drop in natural gas commodity prices and the expected low prices into the future, compared to expected large increases in tier 2 electricity rates, provides the single largest change in business risk for FEI? If not, please explain.

Response:

This response also addresses BCUC IRs 1.2.1, 1.2.1.1, 1.6.2 (b), 1.98.1, 1.99.1, 1.101.1, and 1.106.1 as well as BCPSO IR 1.1.1.

While FEI agrees that the operating cost advantage of natural gas versus electricity compared to the 2009 levels has improved due to the decline in natural gas commodity prices and the increase to electricity rates, FEI does not agree that it was the single largest change in business risk for FEI since 2009. In fact, the decline in commodity price has had little impact on FEI's overall business risk, mainly due to two reasons:

- Firstly, as discussed in Section 5 of Appendix H, natural gas commodity price is one factor impacting price competitiveness of natural gas in BC relative to electricity. Other factors include natural gas price volatility, the relative purchase and installation costs of natural gas appliances compared to electric appliances. As such, even with lower commodity prices, there has not been a significant improvement in FEI's throughput levels (with the exception of industrial load) for space and water heating, which is FEI's core business.
- Secondly, as evident in Appendix H, there are also non-price competitive factors (climate change and energy policies, customer perception of energy and the shift towards smaller, higher density housing), that impact FEI's throughput levels and it is due to these factors that despite the decline in natural gas commodity prices, FEI continues to face business risk trends similar to those identified in 2009.

Each of these reasons are further discussed below. In addition, recent operational and research results will be explored that suggest the business risk FEI faces continues to increase.

Energy Price Risk Factors

There are a number of factors that impact the price competitiveness of natural gas in BC relative to electricity and these include natural gas commodity cost relative to electricity, natural gas price volatility, and relative installation costs of natural gas equipment compared to electric equipment. Despite the fact the natural gas commodity cost relative to electricity has improved over the last few years due to lower commodity prices, the other two factors continue to impact the operating price advantage of natural gas over electricity in BC.

Natural Gas Commodity Prices

Natural gas commodity prices have declined and therefore improved the operating cost of natural gas over electricity in recent years. As stated on page 17 of Appendix H, the operating cost advantage has been partially offset by the carbon tax increases in the same period (from approximately $0.50/GJ in 2008 to $1.50/GJ in 2012). Furthermore, as demonstrated by Figure 22 and 28 of Appendix H, despite the lower commodity price environment over the last couple of years, there has been little change in residential average use per customer and customer additions. Therefore it is difficult to separate what influence lower commodity prices have had on consumption levels from other cost or non-price related factors. The exception is for the industrial sector, whereby, as stated on page 36 of Appendix H, FEI experienced a modest increase in throughput in the industrial sector as some industrial customers have fuel switched towards natural gas to take advantage of the lower natural gas prices compared to their alternatives.

In comparing the natural gas price to electricity, the expected increases in step 2 electricity rates may further enhance the operating price advantage of natural gas. However, there is uncertainty regarding future natural gas prices as discussed in Section 5.1 of Appendix G of the Application and there is no guarantee that this operating price advantage will continue to this degree in the future. It is also worth mentioning the fact that step 2 electricity rates do not apply to all energy consumption (e.g. step 1 applies to water heating). Specifically, many newly constructed homes, which are typically smaller and more energy efficient, consume most of their consumption at the step 1 electricity rate. This is especially true for hot water heating applications in which almost all of a typical residential consumer's consumption is at the step 1 rate. Further, step 1 electricity rates are not expected to increase as much as step 2 electricity rates, and as such, FEI will continue to be especially challenged in retaining and attracting load for hot water heating applications.

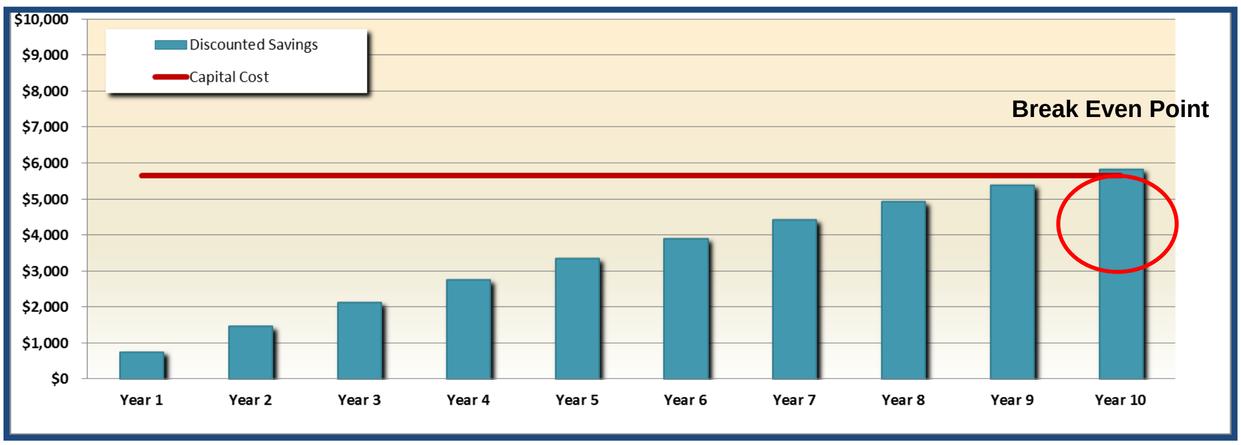
Natural Gas Price Volatility

As discussed in Section 5.2 of Appendix H, many of the past risk mitigation strategies to reduce price volatility are no longer in place and therefore a greater portion of FEI's supply portfolio is subject to market price fluctuations. Therefore, the risk associated with market price volatility is considered to be higher than in 2009, somewhat offsetting the lower risk associated with the drop in natural gas prices.

Upfront and Installation Costs

As discussed in Section 5.3 of Appendix H, natural gas equipment is significantly more expensive than electrical equipment for space heating and this higher upfront capital costs of natural gas end-use applications erodes natural gas' operating cost advantage as compared to electricity and can influence energy choices, particularly because builders and developers tend to be more influenced by capital costs alone. Figures 14 and 15 from Appendix H show that when capital cost is added to the cost of delivered energy (natural gas or electric), the difference in annual costs is much smaller. In fact, as demonstrated in the figure below, if a customer were to calculate when they would break even by using natural gas they would find it takes approximately 10 years to recover the additional cost of natural gas equipment via savings from the operating cost differential between natural gas and electricity.

Capital Cost Recovery for Gas Furnace and Hot Water Tank



Thus, the continued difference in capital cost for natural gas equipment in comparison to electricity equipment means that from a total cost perspective, natural gas may not have a competitive advantage over electricity and as such it is not favored in certain applications, particularly within the multi-family dwellings. As stated in Appendix H (page 24), the impact to the rate comparisons of natural gas against electricity depends on the customer's consumption levels for electricity. For example, water heating load may be better compared to Step 1 electricity rates because it generally has a flat yearly profile versus space heating which would have a winter profile (Step 2).

Previous research conducted in 2010 suggested that builders and developers also install electric baseboard heating solutions because they do not require venting or ducting and they allow for greater floor plan design flexibility. These findings were further affirmed in 2012 when a cross section of builders and developers indicated that:

> *"The two most significant barriers to choosing gas are the up-front capital cost requirements and greater complexity of the installation, relative to electricity. This can be especially challenging in lower cost developments and also MURBs (multi-unit*

residential buildings), where space is at a premium and additional ducting can compromise the utilization of limited floor space."[6]

This means that regardless of any commodity price advantage, FEI will continue to be challenged in capturing new customers.

Non-Energy Price Risk Factors

The decline in commodity price has not resulted in a favorable impact to throughput levels mainly due to other non-price factors, such as climate change and energy policies, as well as risks related to market shifts (such as customer perception of energy and housing types), which are significantly higher since 2009 and all of which continue to challenge FEI in retaining and attracting customers even in the current lower commodity price environment.

Energy Policies and Legislation

As discussed in Section 9 of Appendix H, since 2007 energy policies at the Provincial level have focused on energy efficiency and role of renewable and alternative energy, and more specifically discouraged the use of carbon based fuels, including natural gas (regardless of the energy price differences). Despite new policy developments in the Province in promoting the role of natural gas in the transportation sector, the role of natural gas in its traditional market of space and water heating continues to be challenged by the climate change and energy policies and more local and municipal governments are mandating certain renewable energy solutions in new developments.

In addition, as mentioned on page 12 of Appendix H, regulations and standards such as the proposed changes to National Minimum Efficiency Standards for domestic water heating systems impact and reduce natural gas consumption and use per customer account over time. FEI forecasts that approximately 50,000 water heaters will fail annually. In 2016, natural gas water heaters will require a 0.67 EF and a dedicated electrical plug. In 2020, the minimum EF rises to 0.80. These efficiency standards coupled with higher capital and installation costs for natural gas hot water tanks will dramatically shift the cost advantage to electric models.

Customer Perception of Energy

As discussed in Section 6.2 of Appendix H, whereas energy price may have played a role in customers' energy choices historically, more and more customers are now moving away from choosing natural gas as energy of choice and demanding greener alternatives. In 2011 research conducted by FEI, it is evident that customer commitment to natural gas dropped sharply from 2007 scores. [7] Customers' interest in alternative energy options such as geo-

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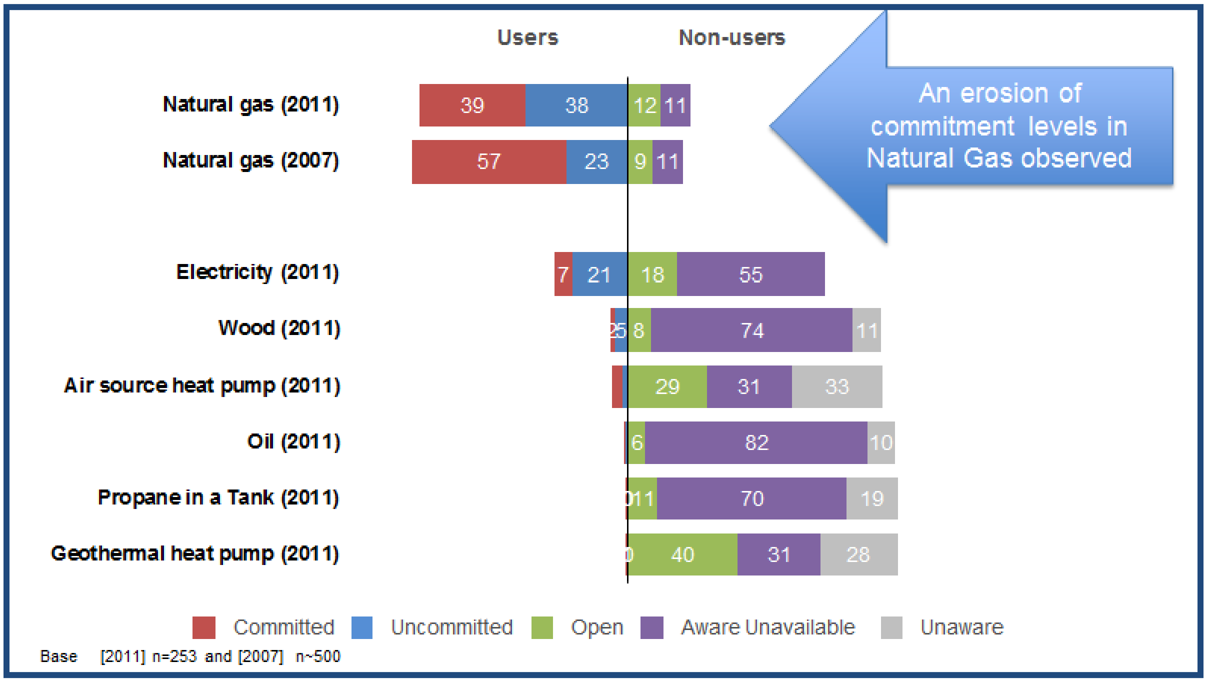
[6] Customer Attachment Study, Ipsos, July 2012, 12-029608-01, pp. 2.

[7] Commitment is calculated using a TNS Global Research approach called the Conversion Model™. This approach measures four dimensions of consumer loyalty as follows:

- Overall rating: How do users and aware non-users rate each energy source?

exchange and air-source heat pumps exceeds that of natural gas or electricity. These results are portrayed in the figure below.

Lower Mainland Space Heating Preferences (2011 versus 2007)



These results reveal that despite the decline in natural gas commodity prices, FEI consumers do not look at natural gas for space heating as favourably as they did in 2007.

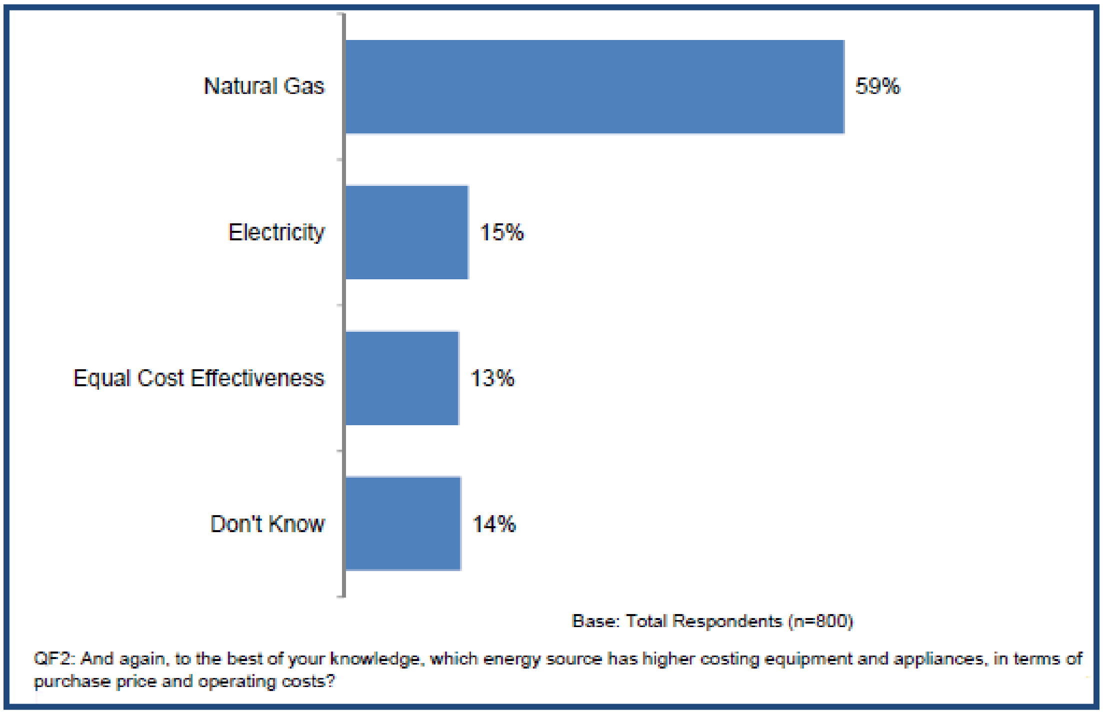
Other results from this same study further illustrate the mounting obstacles that natural gas faces. While a large minority (one in three customers) is either unclear or convinced that electricity is as or more cost effective for heating applications than natural gas, the majority (two in three) believe that natural gas is more expensive in terms of equipment price and ongoing operating costs[8]. This latter result is depicted in the figure below.

- Attitude to alternatives: How do all the alternative energy sources compare?
- Involvement: How important a decision is energy choice?
- Ambivalence: Are there many, few or no reasons to change from energy source currently used?

This research approach segments consumers into four primary groups. Existing natural gas customers can be committed users, people that are not likely to be swayed from using natural gas; or uncommitted. For example, Uncommitted natural gas users are reasonably ambivalent to natural gas and could easily be swayed to choose a competitive energy option. Likewise, there are two non-user groups. These two groups are called Open and secondly, Unavailable non-users. "Open" consumers are willing to consider an alternate energy option. However, those "Unavailable" will not consider the energy as a possible solution.

[8] Energy Source Usage Preferences Study – Topline Results, TNS Canada, December 2011 (R1786), pp. 33, 34.

Energy Source Considered More Expensive for Equipment and Operation



FEI is of the opinion that a contributing factor to some customer misconceptions can be found in results from a 2012 study called, "Alternatives for Managing Natural Gas Price Volatility." This study was undertaken to explore rate alternatives that focus on delivering choice for customers that want rate volatility reduction. To ensure customers understood the different options explored, the study evaluated customers' current understanding of the FortisBC natural gas bill. "Findings suggest that less than half of businesses (45%) and even fewer residents (35%) gave responses indicating that they feel confident that they understand the difference between delivery and commodity charges (assigning a rating of either 4 or 5 on a 5-point scale)."[9] Even after providing customers with the description of the bill charges, a large minority (42% of residential customers, and 33% of business customers) indicated ongoing confusion about their natural gas bill. This finding suggests that many consumers are ill-equipped to effectively compare natural gas and electric heating system costs. Pricing signals available through market commentary or through a comparison of one's electric and gas bills is unlikely to drive an informed investment decision because billing and energy terminology are not well understood by many consumers.

Housing Types and Builder Decision Making

As discussed in Section 6.3 of Appendix H, natural gas has a low penetration rate in multi-family dwellings and the increase in multi-family housing starts in recent years has a significant impact

[9] Alternatives for Managing Natural Gas Price Volatility, Sentis Research, September 10, 2012, pp. 7.

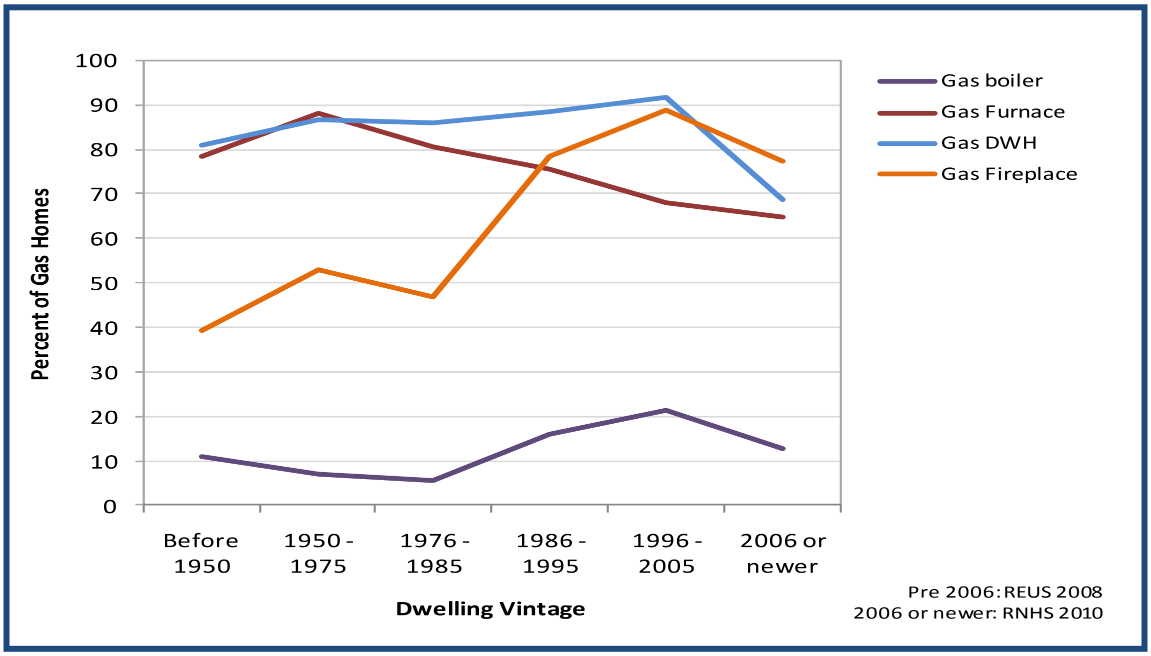
on natural gas use and capture rates. As stated on page 31 of Appendix H, the main underlying factor that influences the declining capture rates of natural gas is that builder decisions are being driven by capital cost savings and the ability to sell more useable living space. As installing natural gas application is economically unfavorable over electric equipment, natural gas will continue to be challenged.

While several of the research references in this response relate qualitative findings, the rapid change in natural gas use in the home is best demonstrated in results from a 2010 FortisBC study called Residential New Construction Research. This report underscores the rapid changes and increased risk FEI currently faces. It evaluated the space and domestic water heating fuels and equipment and other natural gas end-uses in homes built between 2006 and 2010. Results reveal tremendous differences from historic end-use research results. Specifically:

- The proportion of new homes using baseboard heaters is up significantly despite being the least desirable method of space heating from a homeowner's perspective.
- The proportion of gas homes with a gas furnace continues to decline.
- Air Source Heat Pumps ("ASHPs") are installed in 18% of gas homes built since 2005, with the incidence highest on Vancouver Island and in the Interior. As a result, gas is shifting to a secondary space heating role.
- Eight in every ten homes with ASHPs use either a gas furnace or gas fireplace as the other heating method.
- Geothermal is making inroads, with 4% of new homes reporting a geothermal heat pump system.

The figure below depicts the rapid erosion FEI has experienced in natural gas homes relying upon gas solutions for space heating, DWH, boilers and fireplaces.

Gas End-Use Trends – Gas Space & Water Heating



In summary, natural gas commodity price is just one factor that influences the overall price competitiveness of natural gas relative to electricity. Other factors include natural gas price volatility, purchase and installation costs of natural gas appliances, climate change and consumer perception of energy alternatives, energy policies and building codes, and the dramatic shift to higher density housing, especially MURBs. In aggregate, these factors support FEI's assertion that it continues to face business risk similar to that identified in 2009. As such, the FEU do not agree that the recent decline in natural gas commodity prices has been the biggest change to business risk since 2009.

98.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, p. 9

Total Throughput

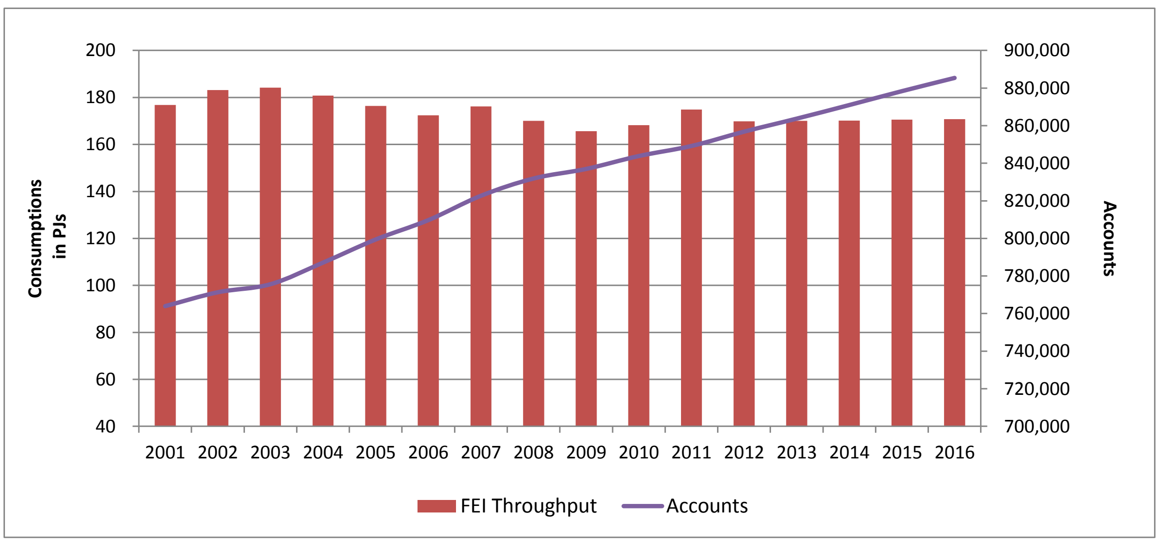
Figure 4 provides historic normalized throughput and customer counts.

98.1 Please update the figure to add FEI's expected throughput and customer counts through 2016 including expected sales to transportation customers.

Response:

The following figure includes FEI's expected throughput and customer counts through 2016.

2001 through 2011 represent actual data. 2012 and 2013 are forecasts from the 2012-2013 RRA filing. 2014-2016 are forecasted values from an internal forecast developed at the same time as the 2012-2013 RRA forecast. The 2014-2016 forecasted values will be updated during the upcoming Long Term Resource Plan and future RRA forecast cycles but represent our best estimates at this time. The values for 2014-2016 were developed using our traditional short term forecast methodologies.



98.2 Based on existing FEI residential gas rates and BC Hydro residential tier 2 rates (excluding basic charge) what is the operating margin between these fuels for an annual use 100 GJ residential customer and an annual use 75 GJ residential customer?

Response:

The table below summarizes the difference in operating margin between BC Hydro's RIB Step 1 and Step 2 electric rates[10] and FortisBC Energy Inc.'s residential natural gas rates[11] for annual consumption amounts of 75 GJ and 100 GJ. The results are also provided for assumed thermal conversion efficiencies for gas appliances of 60% and 90% which provide a reasonable range of efficiencies for the mix of newer and older appliances being used by gas consumers in BC.

		Natural Gas Rate ($/GJ)	Equivalent Electricity Rate ($/GJ)		Operating Margin Advantage of Natural Gas over Electricity by Efficiency ($ per Year)	
			60% Efficiency	90% Efficiency	60% Efficiency	90% Efficiency
BC Hydro RIB Step 1 Rate	75 GJ	$ 11.253	$ 11.90	$ 17.85	$ 49	$ 495
	100 GJ	$ 10.780	$ 11.90	$ 17.85	$ 112	$ 707
BC Hydro RIB Step 2 Rate	75 GJ	$ 11.253	$ 17.83	$ 26.75	$ 493	$ 1,162
	100 GJ	$ 10.780	$ 17.83	$ 26.75	$ 705	$ 1,597

The FBCU have provided the operating margins for a comparison to the BC Hydro RIB Step 1 residential rate as well as the Step 2 rate since both are appropriate reference points for comparing natural gas and electricity as competing energy sources. In practice the majority of residential customers would be at a blend of the Step1 and Step 2 rates for their space and water heating energy requirements, so a straight comparison of natural gas against the Step 2 rate does not provide a realistic picture. Smaller or more energy-efficient dwellings such as townhouses and condominiums may be capable of getting some or all of the energy needed for space heating from BC Hydro's Step 1 block. Furthermore, many homes, regardless of size, may incur only Step 1 rates for their water heating application. This means the Step 1 rate is a relevant comparator that must be considered. With current trends in development focusing on greater energy efficiency and smaller footprint dwellings the relevance of the Step 1 rate in gas and electricity comparisons may increase.

As can be seen in the table the operating margin advantage of natural gas, using 75 GJ or 100 GJ as the annual consumption, can vary from a relatively small amount of $49 per year relative to the BC Hydro Step 1 rate (at 75 GJ/year) to a relatively large amount of $1,597 per year relative to the Step 2 rate assuming 100 GJ per year. Similar to the discussion above, building trends and improved energy efficiency in the existing building stock will also affect the consumption levels that should be assumed in making the comparison between gas and electricity operating costs. In this context, lower levels of consumption such as 50 GJ per year

[10] The current BC Hydro RIB Step 1 and Step 2 rates are $0.0680/kWh and $0.1019/kWh respectively. The current BC Hydro rate rider of 5% is added to these amounts. The conversion factor of 277.78 kWh/GJ is then applied, followed by the assumed relative efficiency factor of natural gas appliances. The calculations assume that either 100 GJ or 75 GJ is the quantity of natural gas needed to meet the customer's energy requirements. If that same load is served by electricity at a higher efficiency (i.e. 100% assumed) less electrical energy is needed to meet the same end use need. Therefore the electricity rates are scaled down by the efficiency factors of the gas appliances of 60% or 90% to get the equivalent electricity rate.

[11] Current natural gas rates are: Commodity Rate - $2.977/GJ, Midstream Rate - $1.365/GJ, Delivery Charge - $3.527/GJ, Carbon Tax - $1.4898/GJ and Basic Charge - $0.389/day, (or $1.894/GJ at 75 GJ/year, $1.421/GJ at 100 GJ/year).

(or less) will be increasingly relevant in making operating cost comparisons and larger amounts such as 100 GJ will cease to be appropriate. FEI's discussion and analysis in Exhibit B1-9-6, Appendix H, page 33 and 34 (especially Figure 23) of the use per customer ("UPC") for new residential customers added in 2008-2010 compared with existing customers supports this assertion. In that discussion the normal UPC for the residential class as a whole is 85 GJ per year while for new customers added in the 2008-2010 period the normal UPC is 45 GJ per year.

Beyond simple operating cost comparisons the FBCU also believe that the additional upfront capital costs and higher ongoing maintenance costs for gas appliances relative to electrical ones represent a barrier to using gas either in new construction or continuing to use gas in existing installations when appliances need to be replaced. When these higher upfront capital costs and extra maintenance costs are considered the operating cost advantage frequently turns into a deficit or at least diminishes significantly. As discussed in the response to BCUC IR 1.97.1, builders and developers are incented to keep capital costs down as they may not be fully recovered in the price of the home. In addition, as customer use rates continue to decline on average and new customers attach at much lower use rates, the opportunity for the volume-based operating cost savings to recover the higher maintenance and upfront capital cost and cost differentials will diminish. The impact of higher capital and maintenance costs on the competitiveness of natural gas relative to electricity is discussed in detail in Exhibit B1-9-6, Appendix H, section 5.3. In particular Figures 15 and 17 illustrate that, with incremental upfront capital and ongoing maintenance costs considered, gas is uncompetitive against the RIB Step 1 electricity rate and is modestly favourable relative to the RIB Step 2 rate.

98.3 In 2016, assuming BC Hydro residential tier 2 rates rise by an average 10 %/yr in 2013, 2014, 2015 and 2016 and natural gas commodity prices rise to $4.50/GJ, please estimate the operating margin of natural gas vs. tier 2 electric prices for the customers in the question above. (If FEI does not agree with the cost parameters of this question, please also provide FEI's estimate and underpinning reasons.) Does FEI agree that the current large price advantage of natural gas service to residential customers will increase over the next 5 years?

Response:

The relative price advantage currently realized by natural gas over electricity is on an operating cost basis only. As stated in the response to BCUC IR 1.98.2 FEI believes that both the BC Hydro RIB Step 1 and Step 2 rates are relevant comparators that should be considered in assessing the operating cost advantage or disadvantage of natural gas relative to electricity. As noted in response to BCUC IR 1.97.1, other factors, such as the higher upfront capital costs of natural gas installations and appliances, also influence the competitive position of natural gas negatively relative to electricity, in spite of any improvements in the operating costs relative to electricity.

FEI cannot predict if the current relative operating cost advantage of natural gas service would improve over the next 5 years. Certainly, this could happen if electric rate increases outpace increases in natural gas market prices however there is a high degree of uncertainty of the extent that this could happen. First, natural gas prices are subject to dynamic market supply and demand factors, and exhibit a high degree of volatility, as discussed in Section 5.1 of Appendix H of the Application. It is widely accepted that current market price levels are not sustainable and future increases are inevitable. As per Figure 11 of Appendix H of the Application, current market price forecasts indicate that natural gas prices could be higher than $5.00/GJ within five years, as supply and demand becomes more balanced. Also, as Figure 13 of Appendix H of the Application illustrates, there is a 95% degree of confidence that natural gas prices will remain within a range of about $1.50/GJ and $10/GJ over the next five years, indicating that there is the potential for prices to move higher.

Second, there is significant uncertainty on the level of electricity rate increases that will be realized by customers over the next 5 years as this is driven not only by BC Hydro's costs but also by public policy. Regardless, FEI does not believe that the above stated assumption that BC Hydro Step 2 rates will rise by 10%/year for each of 2013, 2014, 2015, and 2016 is a likely outcome. Although in the past BC Hydro has issued forecasts of large general rate increases going forward, the provincial government's 2011 review of BC Hydro and its public statements about the intention to control or reduce future rate increases have added a lot of uncertainty to the magnitude of future rate increases and as to manner to which they would be applied to the Step 1 or Step 2 rates in the future. Currently the manner in which BC Hydro's general rate increases are applied to the Step 1 and Step 2 rates is set out in the 2011 RIB Rate Re-pricing Decision (BCUC Order No. G-45-11). Although BC Hydro's detailed models are needed to determine precisely how the increase will be applied to each of the step rates, in general the Step 2 rate will increase by a percentage greater than the general rate increase and the Step 1 rate at a percentage less than the general rate increase, subject to the Step 1 increase being no less than the rate of inflation. This is illustrated with the approved F2012 rate increase where the Step 1 rate increased by 2% (i.e. inflation) and Step 2 by 5.9%, yielding an average rate increase of 3.91% for F2012 (which was the approved general rate increase). Based on the assumption that BC Hydro's general rate increases will be greater than inflation over the next several years FEI has provided two cases for the RIB rates in the tables below. Both cases assume that the Step 1 rates will increase by inflation or 2%/year over the 4 year period (based on the constraint in the RIB Re-pricing Decision.) The first case assumes that the Step 2 rate increases by 5% per year. The second case assumes that the Step 2 rate increases by 10% per year.[12] FEI has assumed that natural gas commodity rates increase to $4.50/GJ as indicated in

[12] The 5% per year and 10% per year increase assumptions for the Step 2 rates are illustrative and are not based on an underlying forecast of BC Hydro general rate increases.

the question, while the delivery charge, midstream rate and carbon tax are kept the same as 2012 levels for the purposes of the calculations below.

Case 1: Step 1 Rate Increases by Inflation (i.e. 2%/year), Step 2 Rate Increases by 5% per year

		Natural Gas Rate ($/GJ)	Equivalent Electricity Rate ($/GJ)		Operating Margin Advantage of Natural Gas over Electricity by Efficiency ($ per Year)	
			60% Efficiency	90% Efficiency	60% Efficiency	90% Efficiency
BC Hydro	75 GJ	$ 12.78	$ 12.88	$ 19.32	$ 8	$ 491
RIB Step 1	100 GJ	$ 12.30	$ 12.88	$ 19.32	$ 58	$ 702
BC Hydro	75 GJ	$ 12.78	$ 21.68	$ 32.51	$ 667	$ 1,480
RIB Step 2	100 GJ	$ 12.30	$ 21.68	$ 32.51	$ 937	$ 2,021

Case 2: Step 1 Rate Increases by Inflation (i.e. 2%/year), Step 2 Rate Increases by 10% per year

		Natural Gas Rate ($/GJ)	Equivalent Electricity Rate ($/GJ)		Operating Margin Advantage of Natural Gas over Electricity by Efficiency	
			60% Efficiency	90% Efficiency	60% Efficiency	90% Efficiency
BC Hydro	75 GJ	$ 12.78	$ 12.88	$ 19.32	$ 8	$ 491
RIB Step 1	100 GJ	$ 12.30	$ 12.88	$ 19.32	$ 58	$ 702
BC Hydro	75 GJ	$ 12.78	$ 26.11	$ 39.16	$ 1,000	$ 1,979
RIB Step 2	100 GJ	$ 12.30	$ 26.11	$ 39.16	$ 1,381	$ 2,686

Both cases indicate that to the extent the RIB Step 1 rate is the relevant comparator the operating cost differentials do not improve. To the extent that the RIB Step 2 rate is the relevant comparator FEI agrees that the operating cost advantage of natural gas over electricity would increase over the next five years if these assumptions on natural gas commodity costs and electric rate increases were to be realized.

99.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, p. 13

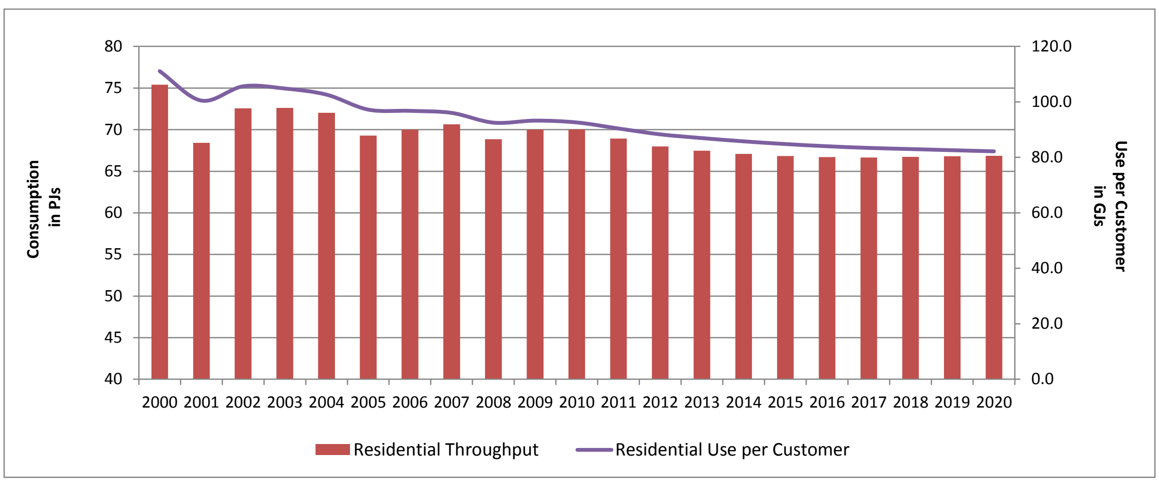
Forecast Residential Throughput Levels

Figure 7 provides a residential throughput forecast from the 2010 Conservation Potential Review.

99.1 Please provide another table of FEI's own forecast of total residential throughput levels from 2000 through2020 reflecting existing and expected future natural gas and electricity prices. On the right axis of the same figure please provide the annual average expected consumption of existing residential customers and new residential customers. Please make explicit all underlying assumptions.

Response:

The following figure provides FEI's throughput and use per customer from 2000 to 2020 for the residential sector. The forecast data from 2012 to 2020 is based on 2010 Resource Plan. Note that gas and electricity price forecasts were not discrete inputs into the 2010 Resource Plan model due to both the difficulty with which these prices can be forecast and the lack of useable correlations (elasticities) between gas cost and demand for natural gas.



For greater clarity, in the decision on the 2010 LTRP the BCUC ordered:

- A description of the new end-use forecasting methodology, how it compares with FEI's traditional demand forecasting approach, and reconciliation of the results of the two different approaches.

- The development of a most likely or reference case demand forecast and outline of the underlying assumptions taking into account potential legislative, regulatory or market transformation changes.
- An integration of the reference case demand forecast with the EEC scenarios and a description of the impacts.
- A detailed outline of New Initiatives and their impact on future demand and GHG reduction targets backed by rigorous analysis of potential scenarios.
- A description of the impact of each scenario on future resource requirements with consideration of the variables which could further affect these scenarios.

Finally, FEI is directed to provide an estimate of the extent to which its proposed programs and initiatives will contribute to the achievement of British Columbia's energy objectives.

As a result of these directives by the BCUC the long term forecast methodology is being reviewed and updated to reflect these directives from the BCUC.

The following assumptions were identified in the 2010 LTRP on pages 76 through 83. Note that these assumptions may change during the development of the upcoming 2013 LTRP.

- Current projections from B.C. Stats estimate the province will add approximately 1.5 million new residents over the course of the next 20 years which will bring the current population of 4.5 million to 6.0 million by 2030.
- The aggregate effect on the Utilities is expected to be an increase of approximately 150,000 customers over this same period, bringing the total number of customers to slightly above 1.1 million by the end of the planning period.
- Declining residential use per customer rates is a phenomenon affecting mature natural gas utilities across North America. This same trend has been observed in most of the Fortis Utilities' service territories except FW.
- The main drivers of this continuing UPC decline include the renewal of existing furnace stock, changes to building codes and standards, and also a shift in housing type from single family dwellings to multifamily dwellings.
- This analysis of furnace age indicates a large portion of the standard efficiency furnaces will be retiring and be replaced with high efficiency furnaces in the coming years. This will have a significant impact on the Utilities' residential average use per customer, particularly in the Lower Mainland which has the largest customer base and the oldest stock of heating equipment among the Utilities service areas. Depending on the housing type and region, we estimate that a typical standard efficiency furnace consumes

approximately 17 to 20 GJ more per year than higher efficiency furnaces. A shift in the existing mix of furnaces from standard efficiency (currently the largest portion) to high efficiency will lead to a significant decrease in residential average use per customer.

- Based on the 2008 REUS, we estimate that standard efficiency furnaces will be completely phased out from its existing customer base sometime between 2017 and 2020 depending on the region. The Utilities estimate the decline in overall residential average use per customer from shifting furnace efficiency to be an approximate 2% per year for the next 3 to 5 years.
- The impact of the continued dominance of multifamily dwellings in the housing market is an estimated decline in residential average use per customer by approximately 0.1 to 0.2 GJ per year.
- The integrated, alternative energy solutions for thermal energy demand being implemented by the Fortis Utilities and others are expected to have only a small impact on natural gas demand initially, growing to a more substantial impact over the longer term.
- Going forward, as more customers engage in efficiency improvements and adopt alternative energy solutions, we expect use rates to trend downward.

100.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, p. 13

Business Profile

Figure 7 on page 13, the FBCU provide an outlook for FEI's residential throughput levels in PJs and in Table 5, the FBCU provide FEI's NGT Demand in GJs.

100.1 Please complete the following table and discuss the extent to which the forecast increase in total NGT demand (a new initiative) over the 2012-2017 period is expected to offset the forecast decrease in residential throughput (a core FEI service) over the same period.

	2012	**2013**	**2014**	**2015**	**2016**	**2017**
A Residential throughput (GJ)						
B Total NGT Demand (GJ)						
Sum of A+B						

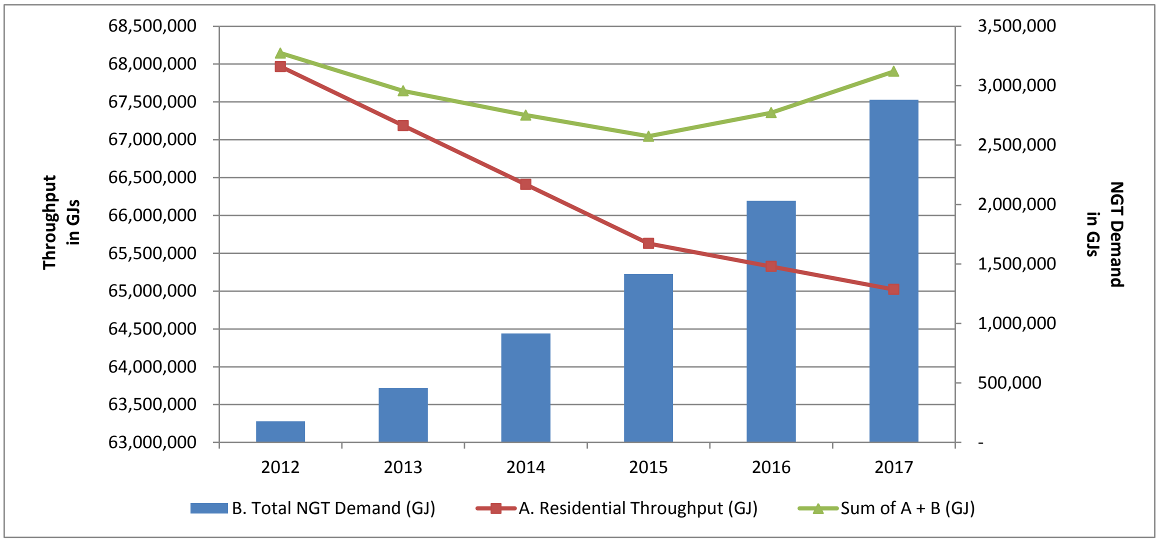
Response:

The following table provides FEI's residential throughput and NGT demand forecast. Residential throughput from 2012 to 2017 corresponds to Figure 7 on page 13, which is provided in the 2010 Conservation Potential Review.

	2012	**2013**	**2014**	**2015**	**2016**	**2017**
A. Residential Throughput (GJ)	67,966,410	67,187,505	66,408,600	65,629,695	65,325,198	65,020,700
B. Total NGT Demand (GJ)	178,000	457,938	917,156	1,416,097	2,032,387	2,882,387
Sum of **A + B** (GJ)	68,144,410	67,645,443	67,325,756	67,045,792	67,357,585	67,903,087

Although FEI believes that the NGT program provides a cost-effective transportation fuel alternative, it is still a relatively new business offering and therefore involves a certain amount of uncertainty. Rate Schedule 16 is currently operating as a pilot program, with an end date of December 31, 2014. This impacts FEI's ability to promote and grow the NGT program, as customers are hesitant to commit to a rate schedule with a temporary status.

Assuming NGT demand grows as expected, the decrease in residential throughput will be partially offset from 2012 to 2014. By 2015 the NGT demand could outpace the decline in residential throughput, as demonstrated in the figure below. The sum of residential throughput and NGT demand could cease to decline by 2015 due to the growing NGT demand. Please note that the NGT demand is shown on the secondary vertical axis.



The comparison on the basis of volumes only tells part of the story. While NGT volumes are forecast to increase, NGT revenue will not offset the declining residential revenues occurring over the same period. NGT rates are lower on a per GJ basis than core customer rates (this is particularly true for customers that select Rate Schedule 25 for their CNG service) and as such a single GJ sold to a NGT customer makes a lesser contribution to delivery margin than would be the case if that same GJ were sold for residential space and water heating load.

So, while the addition of NGT load could undeniably be a positive development, FEI's core market declines in throughput will continue to represent a challenge.

100.2 As the energy industry is evolving and FEI is responding to the changes by undertaking new initiatives, please explain why it remains critical for FEI to attract and retain customers in the traditional heating markets, when FEI can grow the emerging NGT business, a sector that is a priority for the BC Government, as illustrated by the 2012 B.C.'s Natural Gas Strategy.

Response:

As indicated in Appendix H, FEI is and will continue to be a natural gas distribution utility with core business to serve space and water heating in residential and commercial sectors and as such attracting and retaining customers in the traditional space and water heating market is important for existing and new customers. Declining throughput levels mainly due to declining annual use rates from existing customers and the declining rate of capture of the new construction market, particularly in the multi-family sector, impact customer delivery rates and increase FEI's business risk. Although, all else equal, new initiatives, including the NGT initiative, have the potential to partly offset or partly mitigate the increase in FEI's business risk, they do not reduce FEI's current business risk, in absolute terms, and as such do not replace FEI's core business due to, for instance:

- NGT initiative is in early stages of development in the market place and at this point there is not significant uptake in the market. Although the NGT market has promise there is still uncertainty as to how much of the potential will materialize.
- The margin contribution from NGT is likely less than the contribution for space and water heating from the core market given that NGT most likely will be customers that have a lower rate per GJ for delivery service than space and water heating customers, particularly Rate Schedule 1 customers.

101.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, pp. 11 and 20

Market Shares in Alberta and Ontario

Table 4 on page 11 shows market shares for natural gas and electricity in these provinces and Figure 12 (page 20) shows the operating cost differences.

101.1 Recognizing that the operating cost differential between natural gas and electricity is likely to widen in BC for the next several years, would FEI agree that its market share should also improve towards that in Alberta and Ontario? If not, why?

Response:

No, FEI does not agree that an increasing spread between natural gas and electricity rates in BC over the next several is likely to lead to an improvement in market share for natural gas towards that of Alberta and Ontario. Please also refer to the response to BCUC IR 1.97.1

Firstly, there are a number of factors that, together and in combination, influence market share of each energy form and operating cost is only one factor in market share of the energy. In BCUC IR 1.97.1 FBCU have highlighted the effects on gas capture rates of the higher upfront capital costs and ongoing maintenance costs for gas appliances relative to electrical ones. The building trends towards smaller footprint dwellings and greater energy efficiency have also been discussed. Builders and developers are concerned about the potential usable space occupied by furnaces and ducting for gas heating systems and whether they will be able to recoup the higher capital costs in their selling price. Further, recent government policy and regulations in BC with respect to appliance efficiency requirements are creating challenges for using gas in certain end uses such as water heating. Lastly, BC has a different political environment, resulting in carbon taxes for example, that have served to dampen the desire for natural gas. Each of the foregoing issues creates challenges for the gas market share going forward that an improvement in the cost natural gas relative to electricity in BC is unlikely to overcome.

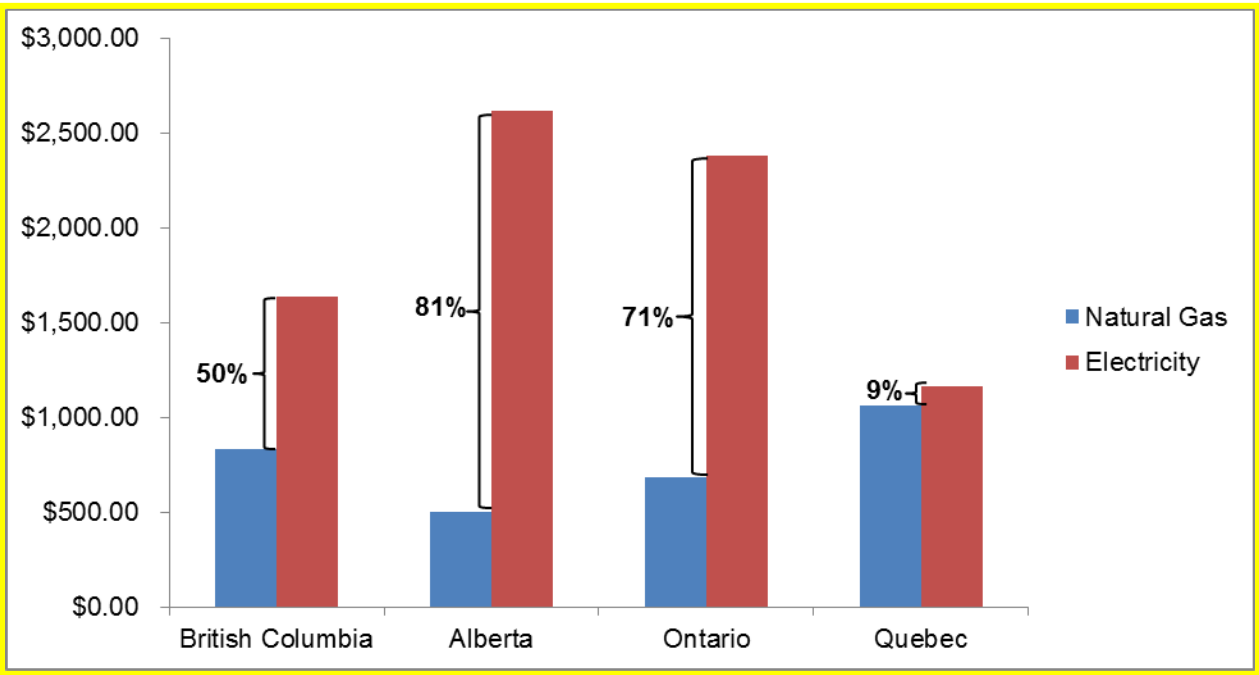
Secondly, even with higher expected electricity prices in the next few years, the spread between electricity and natural gas is expected to continue to be smaller in BC. This is due to the fact that the price of electricity is much higher in Alberta and Ontario and as such natural gas will continue to have a better operating cost advantage against electricity in those provinces than in British Columbia. Alberta and Ontario also face cost pressures with respect to their electricity supply and electricity rate increases in those jurisdictions is also likely to accentuate the price signals consumers there see already with regard to the costs of natural gas versus electricity. Alberta and Ontario have also colder winters than in BC (particularly relative to the Lower Mainland and southern Vancouver Island, the main population centres in BC) meaning thermal energy use rates are higher in those provinces and the savings available to consumers from using natural gas for thermal energy are commensurately higher.

101.2 Please update Figure 12 for estimated bills based on annual use rates of 75 GJ and 100 GJ.

Response:

Please see the figures below reflecting annual use rates of 75 GJ and 100 GJ respectively. Please note that calculations are based on the most recent rates, as at September 1, 2012.

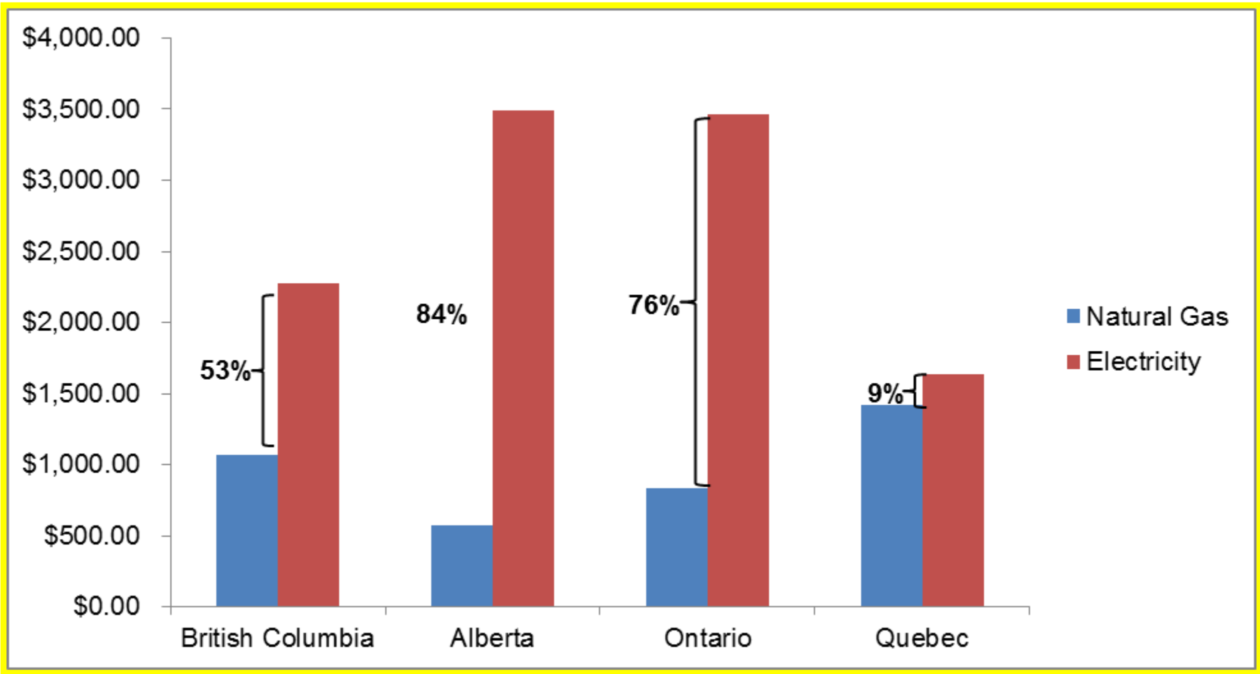
Natural Gas versus Electricity based on 75 GJ's:



Notes:

- The efficiency of gas equipment is assumed to be 90% relative to 100% for electricity to determine equivalent electricity.
- Estimate bills calculated based on annual use rate of **75 GJs.**
- All rates are exclusive of applicable franchise fees and taxes (with the exception of carbon tax).
- Calculations based on rates applicable as at **September 1, 2012.**
- The annual electric rates do not include the fixed monthly charges since it is assumed that a household already pays the basic electric charge for non-heating use.

Natural Gas versus Electrcity based on 100 GJ's:



Notes:

- The efficiency of gas equipment is assumed to be 90% relative to 100% for electricity to determine equivalent electricity.
- Estimate bills calculated based on annual use rate of **100 GJs.**
- All rates are exclusive of applicable franchise fees and taxes (with the exception of carbon tax).
- Calculations based on rates applicable as at **September 1, 2012.**
- The annual electric rates do not include the fixed monthly charges since it is assumed that a household already pays the basic electric charge for non-heating use.

102.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, p. 17

Natural Gas Price Forecasts

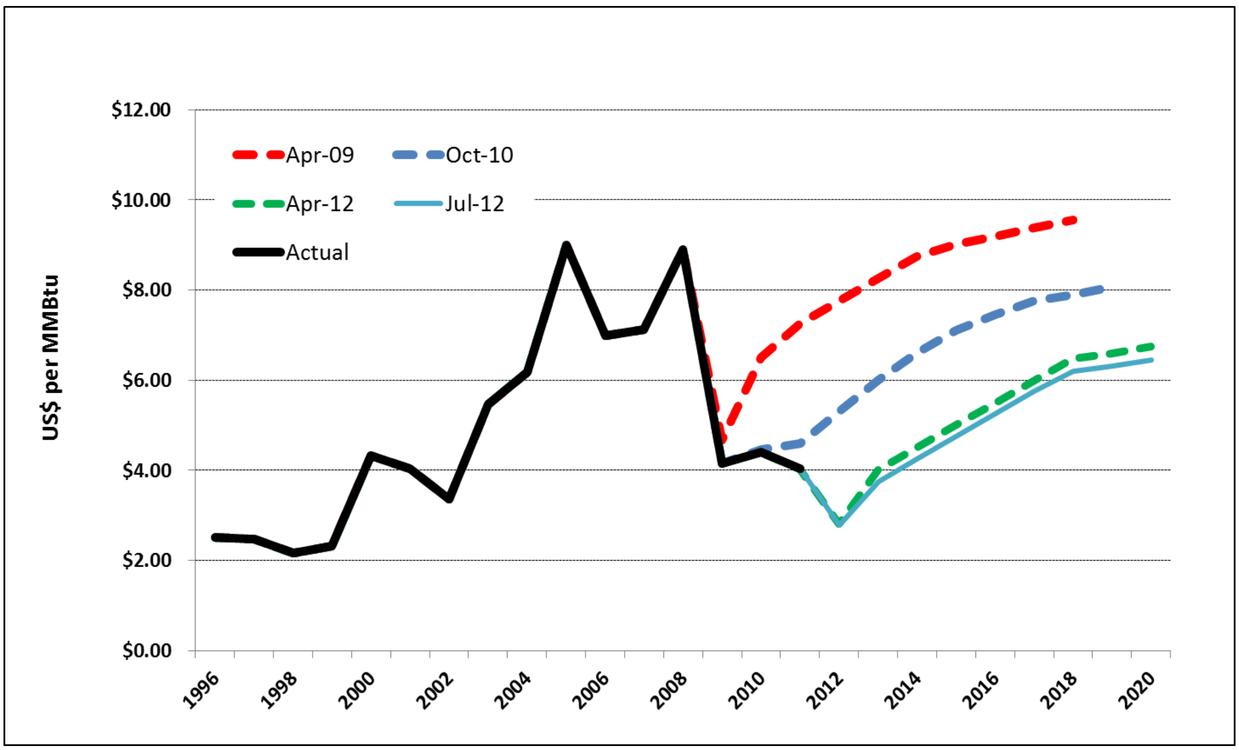
Figure 9 provides a comparison of forward prices of natural gas.

102.1 Please update the figure to include a September strip forecast.

Response:

The data for Figure 9 from page 17 of Appendix H is from GLJ Petroleum Consultants ("GLJ"), which provides independent third party annual price forecasts. GLJ releases its long term price forecasts quarterly on January 1, April 1, July 1, and October 1 of each year.

Therefore, the most recent annual price forecast from GLJ is from July 1, 2012. The figure below is updated to include the July 1, 2012 forecast.



102.2 What is the source of the forecasts?

Response:

Please refer to BCUC IR 1.102.1. Note also that Figure 9 provides a comparison of GLJ's long term annual price forecast at different points in time based on a comprehensive analysis of oil and gas supply and demand data and market trends, and is not a comparison of "forward prices of natural gas". GLJ's current and historical quarterly price forecasts can be viewed at http://www.gljpc.com/.

Please also note that GLJ was erroneously identified as a source for the data included in Figure 8 instead of Figure 9. The other sources identified for Figure 8 are correct.

103.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, p. 17

Natural Gas Price Stability

In a recent decision attached to Order G-120-11, the BCUC stated the following "…However, we also note that in light of the recent exploitation of shale gas, the likelihood for more stable natural gas prices is significantly greater and the risk of dramatically higher natural gas prices, excepting short periods of price disconnects, is significantly lower than it has been in many years."

103.1 Does FEI agree with this statement? If not, why?

Response:

FEI does agree that the current natural gas supply outlook is more favourable as the market has gained greater certainty on the potential of North American shale gas developments. This has resulted in lower gas price outlooks and reduced likelihood that gas prices will increase to the peak levels seen in the 2008 in the near to medium term. However, FEI does not accept that this development significantly increases the likelihood of more stable natural gas prices nor does it significantly reduces the risk that gas prices could be dramatically higher than current depressed levels. In fact, FEI expects that there will continue to be a high level of price volatility as markets adapt to the new natural gas supply and demand market dynamics. For example, as stated on page 18 in Section 5.1 of Appendix H, between the end of March 2012 and the end of July 2012, NYMEX spot prices have increased from below $2.00 to over $3.00 US/MMBtu; in only a matter of four months prices have increased by over 50%.

As discussed in Section 5.1 of Appendix H of the Application, FEI notes that while North American natural gas prices are at their lowest levels in many years due to surplus supply, both producers and end use markets will adapt their consumption and production patterns so that, over time, supply and demand will ultimately rebalance. As the supply and demand balance tightens, natural gas commodity prices are likely to rise from their current levels.

Furthermore, as discussed in the response to BCUC 1.105.1, there continues to be a wide range for potential market prices in the future. As discussed within Section 5.2 of Appendix H of the Application, many of FEI's past risk mitigation strategies to reduce volatility are no longer in place and therefore a greater portion of FEI's supply portfolio is subject to market price fluctuations. As a result, FEI has assessed the risk associated with price volatility to be higher than in 2009 despite the currently lower market natural gas prices.

104.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, p. 19

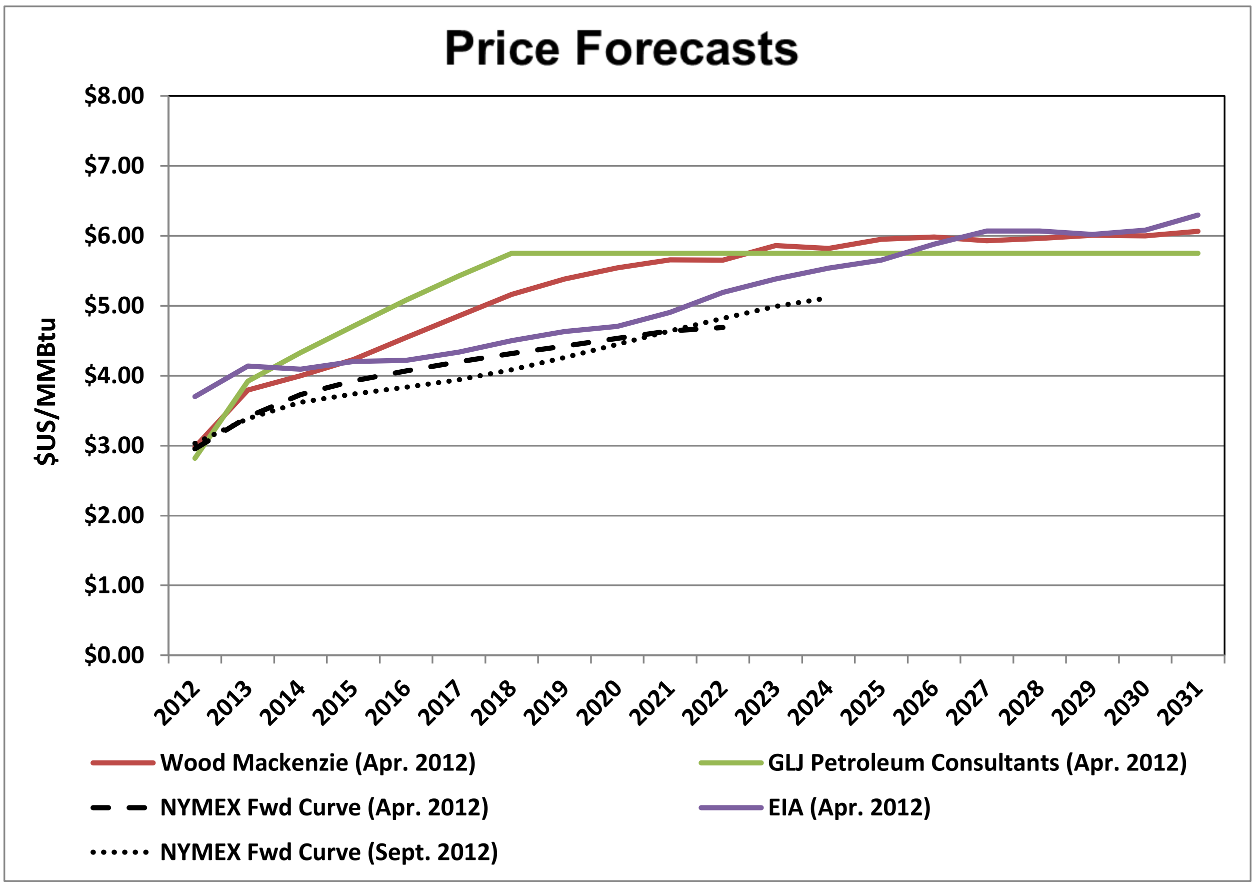
Natural Gas Price Forecasts

Figure 11 provides a comparison of forward prices of natural gas.

104.1 Please update the figure to include the most recent forward prices for NYMEX (Henry Hub).

Response:

The figure below has been updated to include the NYMEX forward curve as of September 4, 2012.



105.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, p. 22

Natural Gas Price Forecasts

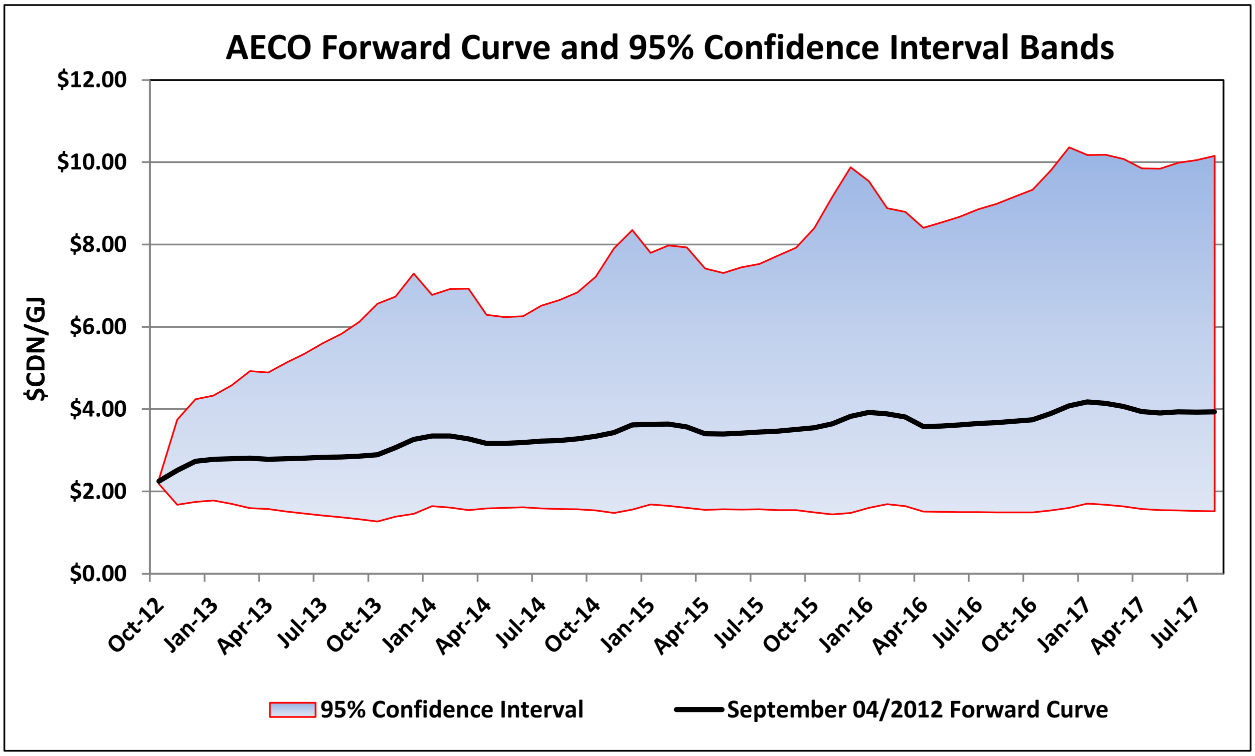
Figure 13 provides a comparison of forward prices of natural gas.

105.1 Please update the figure for a September forward curve and confidence interval?

Response:

Rather than a comparison of forward prices, figure 13 shows the forward AECO/NIT price range using implied volatility, which is derived from the prices for options for AECO/NIT using prices as of April 30, 2012. The figure below provides an update using the September 4, 2012 forward curve and confidence interval using implied volatilities from August 31, 2012. (FEI obtains the market-based volatilities from a third party on a monthly basis only).

As the figure illustrates, recent implied volatility in the market indicates that AECO/NIT prices for November 2014, for instance, with a 95% confidence interval, will be between about $8.00 CDN/GJ and $1.50 CDN/GJ. This indicates that the potential for significant market price volatility still exists in the marketplace and there is significant uncertainty regarding future natural gas prices.



106.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, pp. 24-25

Natural Gas vs. Electricity Price Equivalents

Figures 14 and 15 provide comparisons of natural gas and electricity costs.

106.1 Don't these figures demonstrate that natural gas now has a large price advantage over electric tier 2 prices and a growing total cost advantage over electricity?

Response:

Figures 14 and 15 demonstrate that natural gas currently has a price advantage over electric step 2 prices and that this advantage has grown over the last few years. For this reason, the FBCU have assessed FEI's risk associated with Commodity Price as "Lower" than in 2009 (see p.5 of Appendix H).

Although the risk associated with Commodity Price is properly classified as "Lower" than in 2009, in fact there is no certainty that this competitive advantage will continue in the future. While natural gas prices are currently at their lowest levels in years, prices in the future are expected to increase as the supply and demand balance tightens (per Section 5.1 of Appendix H of the Application). Also, natural gas does not have a price advantage over the step 1 electricity price when capital cost differences are considered (as per Figure 15). For space heating, while some larger homes may pay for electricity based primarily on the Step 2 rate, many homes will pay a combination of the Step1 and Step 2 rates and many smaller homes will pay for electricity based only on the Step 1 rate. Also, as discussed in Section 5.3 of Appendix H of the Application, it is more appropriate to use the Step 1 rate, rather than the Step 2 rate, when comparing costs for hot water heating applications, regardless of the size of the home.

106.2 What is FEI doing to market this advantage?

Response:

Please also refer to the response to BCUC IR 1.97.1 regarding commodity cost differential between natural gas and electric.

The FBCU has not committed to a "mass market" media campaign to better educate and inform end-use customers of this cost advantage. While the FBCU recognizes that end use commodity cost is not the only factor customers consider when making an energy decision, the FBCU do believe that with better understanding of the bill, commodity prices and long term savings, existing customers could view natural gas more favourably if they realize how their bill has declined as a result of the decline in natural gas price especially as compared with electricity.

As also noted in BCUC IR 1.97.1, customer commitment levels to natural gas has declined, along with market share, from 2007 to 2011. As a result of these learning's, the FBCU is reviewing its marketing efforts to better communicate all the advantages of natural gas, not just price, to our customers. Some of these efforts include:

- Sales Team – the FBCU sales team is the driving force, playing a significant and major role in "getting the word out" directly to our major builders and developers and informing them of the price differential. Though recent discussions with this "B2B" customer group, FBCU has been informed that buildings/developers are not in the business of selling our natural gas product. This group does not believe there is enough customer demand, especially in the entry level market, to provide a return for their investment in the incremental costs involved with providing natural gas. Builders and developers are looking to FortisBC to inform the general public of not only the price differential in energy, but also the lifestyle benefits of natural gas and create demand for our product in their buildings. This requires a specific and well executed marketing effort by FBCU. Additionally, the FBCU is working with developers on specific projects to communicate the advantages of natural gas.
- Broad Based Media - The FBCU is currently investigating the option of a broad based media campaign to advertise the benefits of natural gas should there be budget available. The FBCU recognize the sensitivity, from both a Commission and corporate perspective, when it comes to broad based media. As such the FBCU has not used broad based media recently. However, broad based media, such as television is the most efficient channel to communicate advantages of natural gas to the end use customer.

As noted above and in response to BCUC IR 1.97.1, educating potential customers on the operating price advantage is only one step towards success. Current FBCU research indicates that most potential new customers make decisions based on capital cost more than operating costs. It is vital that FBCU shows potential customers the true long-term value of purchasing and installing natural gas equipment. To this end FBCU is investigating how to mitigate the up-front capital cost of both new gas appliances as well as the cost to connect to the system. This could be in the form of incentives, and/or a finance or lease program.

107.0 Reference: FEI Business Risk

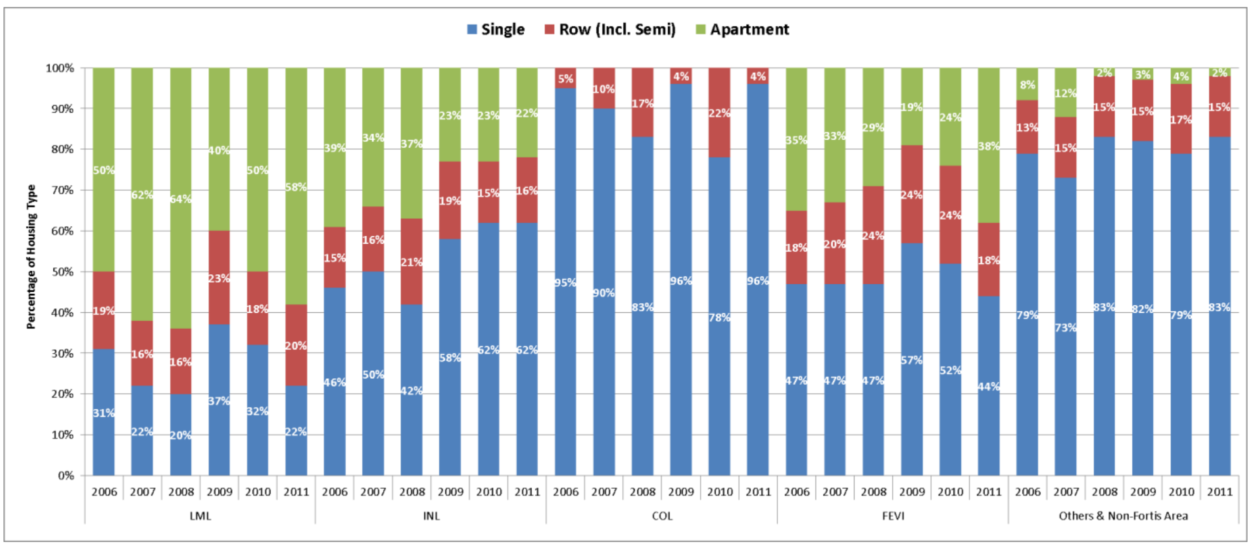
Exhibit B1-9-6, Appendix H, pp. 30-31

Market Shifts – New Technology and Energy Forms – Higher Risk Status since 2009

On page 30, the Evidence of the FBCU regarding Business Risk facing FEI indicates that single family dwelling housing starts have been declining in BC while multi-family housing starts have experienced strong growth, specifically since the declines in 2009. In footnote 25, FBCU states The average consumption for single family detached is about 105 GJ, for duplex is 85 GJs, for row/townhouses is 70 GJs, for mobile homes is 60 GJs, and for apartments is 30 GJs, as per Residential End Use Study, November 30, 2009.

107.1 Please expand Figure 19 on page 30 to show housing starts by types (e.g. singles, row, apartments, and total) and by region in BC starting from 2006.

Response:



For an interpretation of the results please see BCUC IR1 107.1.1.

107.1.1 Does the re-stated Figure show any risk implications that may affect FEU's different service areas? Please explain.

Response:

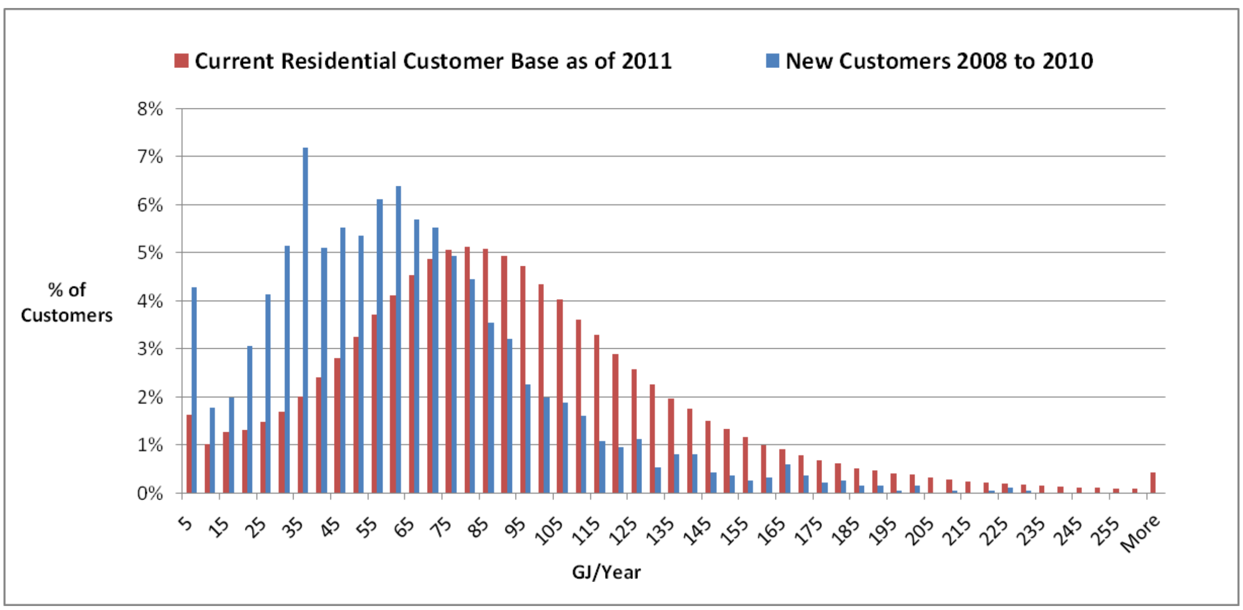
The re-stated Figure provided in BCUC IR 1.107.1 shows a decrease in single family dwellings built in the Lower Mainland and on Vancouver Island since 2009. The Lower Mainland and Vancouver Island accounted for 71% and 12% respectively of BC's housing starts in 2011. The implication is that FEU is facing a challenge attaching new single family customers to the system. While multi-family construction remains strong FEU continues to have a low capture rate in this sector. Inland and Columbia service areas, although adding mostly single family dwellings, only account for 8% of BC's housing starts in 2011 and therefore the impact to FEU is not significant.

107.2 Please clarify whether the average consumption in footnote 25 applies to FEI customers only, or represents average natural gas customers in BC.

Response:

The average consumption in footnote 25 represents the average for all existing natural gas customers in BC.

As shown in the following chart the UPC from new customers is declining compared to the existing customer base. While 62% of new customers use 65 GJs or less, nearly 40% of existing customers use 95 GJs or more. Only 15% of FEI customers added since 2008 use 95 GJs or more annually.



The data used to conduct 2008 Residential End Use Study was collected from over 2,200 residential customers in the Lower Mainland, Vancouver Island, Interior, Whistler and Fort Nelson regions.

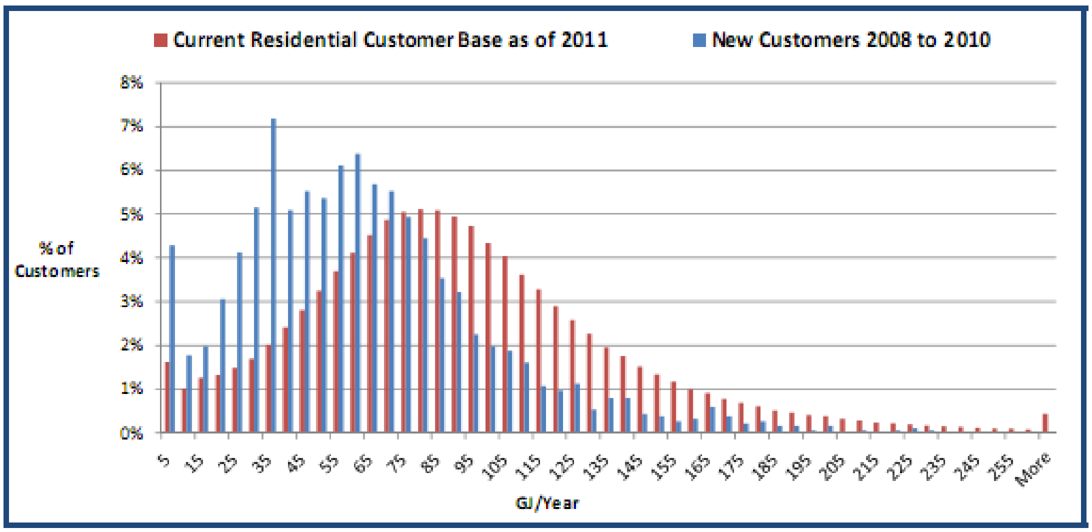
108.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, pp. 31-34

Market Shifts – Changes in Energy Use – Higher Risk Status since 2009

On page 31, the Evidence of the FBCU regarding Business Risk facing FEI states that "FEI is facing declining annual use rates from its existing customers, primarily in the residential sector. This has a direct impact on throughput levels."

Figure 23. FEI's Residential Frequency Distribution



On page 34, the FBCU further state that "natural gas consumption in the residential sector will naturally decline by an additional 2 percent from 2010 to 2030 in the absence of continued demand-side management. The CPR [Conservation Potential Review] also estimated that an additional total reduction in demand of 5 percent by 2030 is mostly likely if new demand-side measures are implemented."

108.1 Since new residential customers have a lower UPC, and in light of the CPR's forecast, do the FBCU believe that the utilities can mitigate risks by limiting new additions of low use residential customers or modifying the current Main Extension Tests to avoid subsidy of low use residential customers? Please explain.

<u>Response:</u>

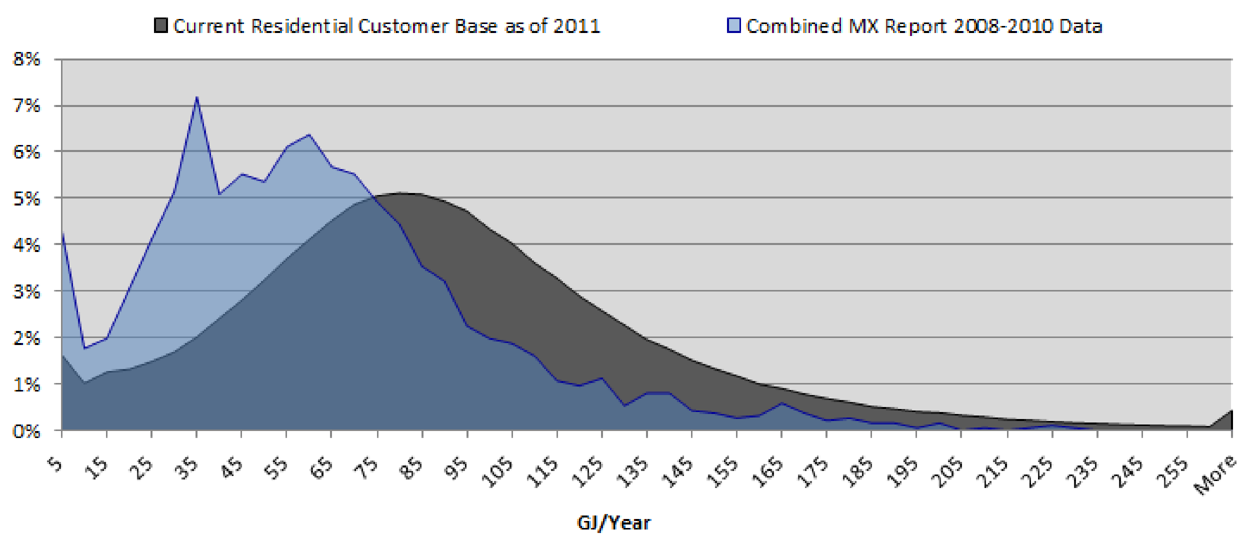
No. The FBCU believe that making it more difficult to attach customers is problematic and counterproductive.

First, the FBCU wish to clarify that the premise of the question regarding the implications of the current MX test is incorrect. The current main extension test (MX Test) does not result in a subsidy to low use residential customers. The current MX Test sends economic signals to residential customers that are choosing to add a small number of low demand natural gas appliances as these customers are more likely to have to provide a contribution in aid of construction (CIAC) than the same customers choosing to add a larger number of relatively high demand natural gas appliances. For example, a builder/developer that only added natural gas fireplaces to dwellings in her project would be more likely to pay a CIAC than if she added natural gas heat and hot water appliances.

Second, as the information described below indicates that lower use per customer is "the new norm", there is an issue of equitable treatment among customers with any policy designed to deter customer attachments as oppose to simply making a reasonable CIAC.

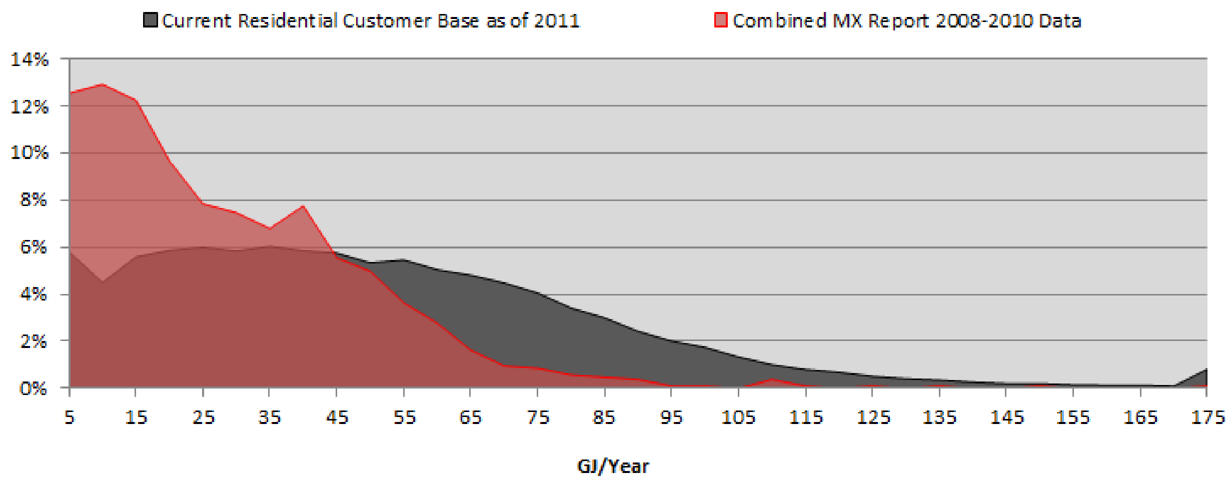
Figures 1 and 2 below are reproduced from the 2011 MX Report.[13] These figures illustrate the trends in consumption of the existing FEI and FEVI customer base, contrasted with the individual residential customer consumption from the 2008 to 2010 random sample data sets that form the basis of the 2011 MX Report.

Figure 1: FEI Consumption per Customer



[13] FortisBC Energy Inc. FortisBC Energy (Vancouver Island) Inc. Main Extension Report for 2011 Year End Compliance Filing in Accordance with Commission Orders No. G-152-07 and G-6-08

Figure 2: FEVI Consumption per Customer



Both figures provide a clear indication that the average use of new residential customers has declined when compared to the totals for the existing FEI and FEVI residential customer base of approximately 770,000 and 93,000 respectively.

There are several factors which may have contributed to the reduction in use per customer as seen above, including successful energy efficiency and conservation (EEC) efforts, marketplace shifts to high efficiency appliances, shift towards multi-family dwellings and a reluctance of customers to incur the high fixed costs associated with installing multiple gas appliances. As technology continues to evolve, EEC programs expand and building codes become more stringent, the Companies expect that these factors will continue to have an increasing impact on new customer consumption levels and the declining trends with respect to the average use of new residential customers will thus continue in the future.

In comparison, the Companies' existing customer base would have faced an entirely different environment when making the decision to connect to the system and, as seen above, had a much higher consumption level per customer. Further, existing customers attached to the system using an MX Test that was less granular and often assumed that all customers attaching would use the average annual consumption, as opposed to regional and appliance specific consumption. As a result, an existing customer would have been less likely to be required to provide a CIAC to reach the requisite profitability index ("PI") threshold than a new customer. Further, as existing customers replace old appliances and upgrade their building efficiency, their average use rate will also decline moving them toward the new "normal".

The Companies believe that current and future customers should be treated in a similar fair and equitable manner when applying the MX Test to main extensions. By holding new customers, whose lower usage patterns represent the 'new normal', to a test designed to attach larger volume customers from an earlier era there is potential for intergenerational inequity to occur. As such, in response to the shift in consumption patterns noted above, the Companies intend to monitor and, if appropriate, conduct a review of the MX Test, the related consumption inputs and the PI thresholds.

Any future review of the MX Test and PI thresholds will need to take into account the declining UPC of new customers described above, the average appliance energy usage inputs used in the MX Test as well as the PI thresholds, and the usage and trends in usage of existing customers. Simply making the MX Test more stringent by raising the PI threshold would be counterproductive for customers as it would result in more customers needing to provide a CIAC and likely choosing not to use natural gas thereby putting upward pressure on rates and creating potential equity issues among groups of customers.

109.0 Reference: FEI Business Risk

Exhibit B1-9-6, Appendix H, pp. 5, 56

Regulatory Risk – Administrative Penalty – Higher Risk Status since 2009

On page 5, the Evidence of the FBCU regarding Business Risk facing FEI indicates that Regulatory Risk is ranked first and that it is higher now than 2009. On page 56, the FBCU state "The amended *UCA* gives the Commission the authority to impose administrative monetary penalty against a public utility in the event that the utility is found to have contravened a provision of the *UCA*, the regulations, or a Commission order or rule. This represents a significant change to the former provisions of the *UCA*, under which a contravention by the utility of a *UCA* provision or a Commission order or rule constituted an offence, subject to prosecution in a court system."

109.1 Are FBCU aware that these proposed penalties have been proposed for violations of the gas marketer code of conduct and for violations of the BCUC approved electric Mandatory Reliability Schedules? To what extent do the FBCU anticipate they will be used against FEI?

Response:

As the FBCU understand it, when the BC Ministry of Energy and Mines was considering proposing amendments to the UCA to strengthen the enforcement powers of the BCUC, the primary reasons cited for such consideration were that (1) some natural gas marketers have acted in contravention of commission rules and orders and (2) a number of parties newly subject to the mandatory reliability standards (MRS) may have failed to comply with commission standards. Although the reasons for enacting the legislation appear to address violations of commission rules and orders by gas marketers and violations of the MRS, administrative penalties may be imposed for violations of any Commission orders, rules or standards. That said, the FBCU anticipate that the Commission will use administrative penalty provisions judiciously. FEI's expectation is that an administrative penalty levied against FEI of any material nature would and should be very rare, as FEI is not engaged in gas marketing or has very limited function with respect to MRS.

109.2 Please elaborate on how penalties that are subject to prosecution in a court system would potentially have lower risk than administrative penalties imposed by the Commission's authority.

Response:

The introduction of administrative penalties means that there are now two avenues whereby a person, including a public utility, can be pursued for breaches of the Act.

The offence provision under section 106 of the UCA has been enacted since 1980. The FBCU have not been able to find any court cases dealing with offences under the UCA, suggesting that the likelihood of Crown Counsel to pursue such offences is low. This may be in part due to the fact that prosecuting an offence in court can be time consuming and expensive as much of the procedure for an offence going through the court system is governed by the *Offence Act*. In contrast, administrative proceedings tend to be more flexible in nature.

109.3 Do FBCU view that the Regulatory Risk resulting in any administrative penalties is within the utility's full control, as opposed to uncontrollable risks such as economic conditions, energy prices, or regulatory lag? If not, please explain.

Response:

There may be instances in which the conduct that resulted in an administrative penalty is within the utility's control; however, the FBCU are of the view that the regulatory risk resulting from administrative penalties is not within the full control of a utility. Circumstances could potentially arise in which the utility and its officers have acted in a manner that they regard as being consistent with the Act and Commission orders etc., but where the Commission takes another view. In the past, these disagreements were unlikely to result in a prosecution and fine. Although the FBCU expect the administrative penalty provisions to be used judiciously by the Commission, the uncertainty that they present (both in terms of how they are administered, and the amount of any penalty) gives rise to this risk.

B. ESTABLISHMENT OF A BENCHMARK ROE BASED ON A BENCHMARK LOW-RISK UTILITY EFFECTIVE JANUARY 1, 2013 TO DECEMBER 31, 2013 FOR THE INITIAL TRANSITION YEAR

110.0 Reference: Hypothetical versus Specific Utility as Benchmark

Exhibit B1-9, p. 2; Exhibit B1-9-6 Testimony of Ms. McShane pp. 14-16

FEI as Benchmark Utility

The FBCU propose that FEI, as it exists today, remain the benchmark for the purposes of determining the allowed rate of return for all other BC utilities until the next Commission review of the benchmark.

Ms. McShane, in her testimony, states "The designation of one utility as the benchmark utility is partly a matter of efficiency, i.e., it avoids frequent reassessment of factors that are common to all utilities. In addition, it provides a means of ensuring that all the utilities subject to the jurisdiction of the Commission are awarded overall returns that appropriately reflect their business risk relative to the benchmark utility, and , in turn, relative to each other.

……

Given both objectives, it makes most sense to designate a specific utility as the benchmark utility, rather than to rely on a hypothetical construct or hypothetical utility as the benchmark.

……….

FEI is the logical choice to serve as the benchmark BC utility. FEI is the largest investor-owned utility in British Columbia, is one of the largest gas distribution utilities in the country, and has a relatively diverse geographic, customer and asset base. It has no exceptional business risk characteristics that are likely to make comparisons with other BC utilities problematic.

….

The proposed amalgamation does not invalidate designating FEI as the benchmark BC utility, as comparisons with other BC utilities can be made based on the characteristics of FEI pre-amalgamation for purposes of establishing their cost of capital by reference to the benchmark utility. In addition, FEI pre-amalgamation can be used as the benchmark utility for establishing the cost of capital for FEI Amalco, should amalgamation proceed."

110.1 Please provide a detailed description on FEI as a benchmark utility for other utilities in B.C. for the purpose of setting their allowed returns (capital structure and ROE). In your description, please include the following:

a. Size (gross and net revenue, customers, rate base, products and services, employees, etc.)

b. Ability to attain an 'A' rating on a standalone basis

c. Traditional core business and, in the short term future, the expansionary opportunities in new initiatives

d. Perception by investors in debt and equity

e. FEI's risks as a benchmark relative to the lowest risk utilities, other low risk utilities as described by the credit and equity analysts, and other non-regulated companies.

Response:

Please refer to the response to BCUC IR 1.111.1 as this question appears to be a duplicate.

110.2 Do the FBCU consider that FEI is a utility undergoing transformation? E.g., transformation relative to its affiliated companies such as FEVI, FEW? Relative to other regulated utilities in B.C. such as PNG, BC Hydro?

Response:

Please refer to the response to BCUC IR 1.111.2 as this question appears to be a duplicate.

110.3 In the view of the FBCU, could the FEI of 2009 – to be treated as frozen in time --- be used as the hypothetical benchmark ROE for 2012 and beyond? Why or why not?

Response:

Please refer to the response to BCUC IR 1.111.3 as this question appears to be a duplicate.

110.4 In the view of the FBCU, can FEI, as it exists today and regardless of changes in the next few years, be used as the benchmark ROE for the next 3 to 5 years and have the future FEI and other utilities' risks and allowed returns on cost of capital evaluated against this entity? Why or why not?

Response:

Please refer to the response to BCUC IR 1.111.4 as this question appears to be a duplicate.

111.0 Reference: Hypothetical versus Specific Utility as Benchmark

Exhibit B1-9, p. 2; Exhibit B1-9-6 Testimony of Ms. McShane pp. 14-16

FEI as Benchmark Utility

FBCU propose that FEI, as it exists today, remain the benchmark for the purposes of determining the allowed rate of return for all other BC utilities until the next Commission review of the benchmark.

Ms. McShane, in her testimony, says:

“The designation of one utility as the benchmark utility is partly a matter of efficiency, i.e., it avoids frequent reassessment of factors that are common to all utilities. In addition, it provides a means of ensuring that all the utilities subject to the jurisdiction of the Commission are awarded overall returns that appropriately reflect their business risk relative to the benchmark utility, and , in turn, relative to each other.

……

Given both objectives, it makes most sense to designate a specific utility as the benchmark utility, rather than to rely on a hypothetical construct or hypothetical utility as the benchmark.

FEI is the logical choice to serve as the benchmark BC utility. FEI is the largest investor-owned utility in British Columbia, is one of the largest gas distribution utilities in the country, and has a relatively diverse geographic, customer and asset base. It has no exceptional business risk characteristics that are likely to make comparisons with other BC utilities problematic.

….

The proposed amalgamation does not invalidate designating FEI as the benchmark BC utility, as comparisons with other BC utilities can be made based on the characteristics of FEI pre-amalgamation for purposes of establishing their cost of capital by reference to the benchmark utility. In addition, FEI pre-amalgamation can be used as the benchmark utility for establishing the cost of capital for FEI Amalco, should amalgamation proceed.”

111.1 Please provide a detailed description on FEI as a benchmark utility for other utilities in B.C. for the purpose of setting their allowed returns (capital structure and ROE). In your description, please include the following:

a. Size (gross and net revenue, customers, rate base, products and services, employees, etc.)

Response:

See the Annual Information Form submitted by FBCU as part of Section 1 of FEI's Company Specific Information filing.

b. Ability to attain an 'A' rating on a standalone basis

Response:

FEI is currently maintains an 'A3' rating by Moody's and an "A" rating from DBRS.

c. Traditional core business and, in the short term future, the expansionary opportunities in new initiatives

Response:

The traditional core business is and will remain the transmission and distribution of natural gas to residential, commercial and industrial customers. While FEI is pursuing new initiatives, these initiatives to date are relatively minor in comparison to the core business. Please refer to the response to BCUC IR 1.6.1.

d. Perception by investors in debt and equity

Response:

FEI maintains ratings in the A category and is active debt issuer and believes it is well perceived by debt investors. As FEI is a wholly owned subsidiary of Fortis Inc., it does not have equity investors other than its parent.

e. FEI's risks as a benchmark relative to the lowest risk utilities, other low risk utilities as described by the credit and equity analysts, and other non-regulated companies.

Response:

FEI's risks are outlined in the Business Risk Appendix submitted as part of its filing. Ms. McShane and Dr. Vander Weide address the relative risks of utilities in other provinces and the United States. Credit rating agency reports do not provide a company to company comparison of business risks to FEI. As noted in analyst reports, regulated utilities are lower risk than non-regulated companies.

111.2 Do FBCU consider that FEI is a utility undergoing transformation? E.g., transformation relative to its affiliated companies such as FEVI, FEW? Relative to other regulated utilities in B.C. such as PNG, BC Hydro?

Response:

As noted in the responses to BCUC IRs 1.111.1 and 1.6.1, FEI's core business is, and will remain for the foreseeable future, natural gas distribution.

PNG and BC Hydro are not appropriate candidates to serve as a benchmark. This assessment is not so much related to whether or not they are in transition, but due to their underlying characteristics. For instance, PNG is a relatively small utility while BC Hydro is a Crown corporation. Please refer to Ms. McShane's evidence for further discussion of this matter.

111.3 In the view of FBCU, could the FEI of 2009 – to be treated as frozen in time --- be used as the hypothetical benchmark ROE for 2012 and beyond? Why or why not?

Response:

It is more efficient to adopt the proposed approach of using the "FEI of 2012", and there are no discernible benefits associated with adopting the "FEI of 2009" instead of the "FEI of 2012". The Commission has a full evidentiary record of what FEI's characteristics are at present. The more out of date the benchmark is, the less the benchmark cost of capital reflects current capital market conditions. As such, the evidence put forward by individual utilities in establishing an equity risk premium will have to include more of that type of evidence as well as their evidence on underlying business risk. Please also refer to the response to BCUC IR 1.113.4.

111.4 In the view of FBCU, can the FEI, as it exists today and regardless of changes in the next few years, be used as the benchmark ROE for the next 3 to 5 years and have the future FEI and other utilities' risks and allowed returns on cost of capital evaluated against this entity? Why or why not?

Response:

FBCU are of the view that FEI as it currently exists can serve as the benchmark for the next 3 to 5 years, until the next determination as to what entity will form the appropriate benchmark. Should amalgamation proceed, FEI Amalco may be determined to be the appropriate benchmark in the future. Alternatively, utilities may use FEI as it is currently comprised as a reference benchmark. Please refer to the response to BCUC IR 1.111.3.

111.5 Specifications of a hypothetical benchmark

FEI – BENCHMAKR UTILITY	HYPOTHETICAL BENCHMARK UTILITY
Customer Mix of FEI (% share): • Industrial • Commercial • Residential	
Customer Class Margins	
Competitiveness of Natural Gas (commodity, delivery, carbon tax, etc.) to Other Fuels (e.g., electricity)	
Size of FEI Capital expenditure ($) Sales ($) Number of employees Rate Base	
Size of debt ($, % of capital structure) and Cost of Debt	
State of plants and equipment	
List of risk mitigation deferral accounts	

FEI – BENCHMAKR UTILITY	HYPOTHETICAL BENCHMARK UTILITY
Financial Metrics 5-year indicative spreads (bps) 10-year indicative spreads (bps) 30-year indicative spreads (bps) Credit ratings Credit ratios (EBITDA/interest, FFO/total debt Debt issuance and long term debt maturity schedules	

111.5.1 The table above lists a number of features and characteristics (non-exhaustive) of FEI that as a benchmark, other actual utilities and B.C. are compared to in order to establish ROE and capital structure differentials. Please fill out the left hand column in the above table and add other features that FBCU consider to be defining features.

Response:

FBCU agree that the features listed in the left hand column can inform the benchmark utility's cost of capital. FBCU would add that all of FEI's business risks (i.e. not just the competitiveness as itemized in the third row) should also be considered as characteristics of the benchmark. FEI's business risks are discussed in FEI's Business Risk Appendix.

111.5.2 If the Commission chose a hypothetical benchmark utility, could FBCU explain how the Commission should compare actual utilities in B. C. to the hypothetical benchmark in the right hand column in order to establish actual risk factors and estimate ROE and capital structure differentials. In what aspects should the hypothetical utility be defined as identical to FEI and in what aspects could it be different so that the hypothetical utility could be described as a low-risk utility?

Response:

Irrespective of what benchmark is selected, the comparison would involve a comprehensive assessment of the characteristics of another utility to the characteristics of the benchmark. The types of features that will inform that inquiry include those features listed in the table in the preamble. However, as noted in the response to BCUC IR 1.111.5.1 a key element of the assessment will be an assessment of the underlying business risks of both the benchmark and the other utility. The business risks are not adequately captured in the table above, which refers only to competition among energy sources. It is in the area of identifying and comparing relative business risks that the FBCU find particularly problematic when it comes to adopting a hypothetical benchmark.

Since the assessment of cost of capital involves a holistic assessment of risks and characteristics of a utility (whether benchmark or otherwise), it is not practical to go through the list of features included in the above table and identify specific factors that, if varied, could reduce the overall risk of the benchmark to the point where it could be characterized as "low risk".

The FBCU believe that it is not necessary to have any particular label – "low risk" or otherwise - attached to a benchmark for it to be an effective benchmark. As a practical matter, given the subjectivity of such labels, avoiding them can avoid unnecessary debate among stakeholders.

112.0 Reference: Application of the Fair Return Standard

Exhibit B1-9, pp. 2, 10, 28

Periodic Review of the Benchmark Allowed Rate of Return

The FBCU propose that FEI, as it exists today, remain the benchmark for the purposes of determining the allowed rate of return for all other BC utilities until the next Commission review of the benchmark.

The FBCU's position is that a review of the benchmark ROE and capital structure every three to five years, rather than a ROE AAM that makes annual adjustments, is the appropriate means for determining the benchmark ROE and capital structure.

112.1 Do the FBCU have in mind what should be the events that should trigger for the next review of the benchmark after this generic proceeding?

Response:

FBCU are of the view that the Commission may determine an appropriate time frame for the next review in the range of 3 to 5 years. Within that time frame, should the FBCU believe that the fair return standard is not being met, an application may be brought forward. Please also refer to the response to BCUC IR 1.113.4.

112.1.1 If the amalgamation proposal for FEVI, FEW and FEI is allowed to proceed, would this trigger a review without having to wait three to five years?

Response:

No. In the event that the amalgamation proceeds, FEI Amalco would determine what a specific equity risk premium to the benchmark utility would be in a subsequent hearing.

112.2 Do the FBCU agree that updating the parameters of a ROE AAM annually is not the same as reviewing the AAM formula for the purpose of adjusting or modifying the formula?

Response:

Agreed.

113.0 Reference: FBCU AAM evidence

Exhibit B1-9, p. 28

Regulatory Efficiency

FBCU state"…the ROE should be determined in periodic Commission processes. The appropriate period between reviews should be three to five years. However, the resulting ROE and capital structure for all affected utilities must always meet the Fair Return Standard. Any affected utility, or interested party, should remain at liberty to seek an adjustment if the cost of capital no longer meets the Fair Return Standard as a result of emerging circumstances during the period between anticipated proceedings."

113.1 If the Commission were to determine that periodic reviews should be limited to three to five years, do the FBCU see merit in some form of AAM to adjust utility ROE's in the intervening years?

Response:

To the extent that an AAM could be developed that with confidence could determine a fair ROE, then an AAM may have some merit.

The FBCU understand that the AAM could be reviewed every three to five years as Concentric has noted, and also understand that the FBCU have identified the need to review the ROE and capital structure of the benchmark every three to five years in any event. The concern that the FBCU have with the AAM is that the basis upon which the annual ROE adjustments are being made may be suspect. The inputs in an AAM are necessarily imperfect, and the track record with AAMs in recent years has not been reassuring. The FBCU would prefer to have the allowed ROE and capital structure be set through a traditional process and remain constant between the periodic (3-5 year) reviews (subject to events occurring that bring the results out of alignment with the Fair Return Standard), than to have updates made on a basis that the FBCU and its experts believe are suspect.

The process that the FBCU are advocating is no less efficient than having an AAM accompanied by a comprehensive review every three to five years.

113.2 If an AAM were established for the intervening years, do the FBCU consider the OEB or Regie AAM to be an appropriate mechanism? Why, and are their other features that FBCU would suggest to improve the AAM while still making it efficient to operate?

Response:

As noted, the FBCU at this time do not believe an AAM should be established. This view is based in part on the fact that the FBCU do not believe an AAM can appropriately capture all the varied factors that affect the benchmark ROE in a simple formula. Therefore the FBCU do not believe either AAM noted above to be an improvement on the proposed approach to establishing the benchmark ROE.

113.3 Are there other conditions which should apply for the intervening years between hearings, such as the Long Canada bond yield not fluctuating by more than 2-3 percent, etc.?

Response:

Please refer to the responses to BCUC IRs 1.113.1 and 1.113.2.

113.4 With conditions like those considered above, and recognizing the high cost and time commitment to a cost of capital proceeding along with the judgmental nature of the evidence and determinations, would the FBCU reconsider its statement "Any affected utility, or interested party, should remain at liberty to seek an adjustment if the cost of capital no longer meets the Fair Return Standard as a result of emerging circumstances during the period between anticipated proceedings."

Response:

No, the FBCU would not reconsider its statement. While FBCU fully appreciates the time commitment and cost associated with proceedings, it should always have the ability to address situations that may result in an allowed ROE that is less than required to meet the Fair Return Standard. The ability of any party to apply to the Commission exists in any event – either with an AAM or not – as it is a fundamental procedural right. The Commission would err in law if it were to seek to preclude a future Commission Panel from considering whether the fair return standard is continuing to be met.

114.0 Reference: Application of the Fair Return Standard

Exhibit B1-9, p. 34

Cost of Capital for FEI as Benchmark

The FBCU submit that the Commission should give recognition to the ongoing challenges posed by the volatility and uncertainty in financial markets, in particular equity markets. Consideration should also be given to the ongoing business risk trends faced by the benchmark utility in B.C.

The FBCU submit that the Fair Return Standard is met in this Proceeding by the benchmark utility, FEI, having a capital structure that includes a 40 percent equity ratio, and a ROE of 10.5 percent.

114.1 Are the FBCU proposing the capital structure of 40 percent equity ratio and a ROE of 10.5 percent effective January 1, 2013 or any other date? Please provide detailed reasons in your response.

Response:

Based on FBCU's understanding of the intention of the Commission in this hearing, the Benchmark ROE and Capital Structure would be effective no earlier than January 1, 2013.

115.0 Reference: Application of the Fair Return Standard

Exhibit B1-9-2 Appendix A Section 3A, RBC Capital Markets Research Report dated

February 10, 2012

Cost of Capital for FEI as Benchmark

The RBC report states on page 2 that on December 8, 2011, the Alberta Utilities Commission released its GCOC decision where, among others, it reduced the allowed ROE for Alberta based utilities to 8.75% (from 9.0% previously) for 2012 and on an interim basis for 2013. Also the RBC reports states that the decision to reduce the ROE was applied retroactively to Q4/11, negatively impacting FortisAlberta's earnings by $2 million. The report further states that as part of the process to finalize the 2013 ROE, the AUC noted that it would re-examine the potential to bring back a formula-based automatic adjustment mechanism.

115.1 Please confirm FBCU's understanding of the AUC decision as described above. If FBCU cannot confirm, please state FBCU's own understanding.

Response:

The report is consistent with the FBCU's understanding, except for the comment, "that the decision to reduce the ROE was applied retroactively to Q4/11." It is the FBCU's understanding that the allowed ROE for all of 2011 was 8.75%.

116.0 Reference: Trends in Economic and Capital Market Conditions since 2009

Exhibit B1-9-6 Appendix F Testimony of Ms. McShane pp. 31, 32

Price Earnings Ratios

Ms McShane analyzed the S&P/TSX Composite and S&P/TSX 60 indexes' reported earnings and dividends and concluded that since September 2009 and at the end of June 2012, the two price indices were little changed from their September level. The resulting index price/earnings (P/E) ratios were lower (and the dividend) yields were higher) at the end of June 2012 than at the end of September 2009.

116.1 Is Ms. McShane able to confirm that in the intervening period between September 2009 and June 2012, the S&P/TSX Composite and S&P/TSX 60 indexes fluctuated widely?

Response:

Yes, it is confirmed.

116.1.1 Please provide the range of the above two indexes (i.e., highest and lowest at day's closing) for the 33 month period.

Response:

Between September 1, 2009 and June 30, 2012, the highest and lowest daily closing prices for the S&P/TSX Composite were 14,270.53 and 10,689.78. The highest and lowest daily closing prices for the S&P/TSX 60 were 819.25 and 640.57.

116.2 Ms. McShane concludes that the market cost of equity has moved higher in the interim period from the table presented in Table 3 of her testimony. Please explain how this logic supports Ms. McShane's basic premise that the allowed ROE will remain unchanged for at least three years (page 4, Appendix F).

Response:

Ms. McShane recognizes that the equity markets have been volatile since the end of the oral portion of the 2009 ROE proceeding, and, given global economic conditions, are likely to continue to be volatile. Ms. McShane's objective was to develop and recommend an ROE that could remain in place for at least a three-year period, despite the volatility, to balance the difficulty of constructing a valid formula at this point in time and the desirability of avoiding a further cost of capital proceeding in the immediate future.

117.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, pp. 3, 11 (2012 Concentric Update)

AAM – Ontario Energy Board

On page 3, the Concentric Update states "In December 2009, the Ontario Energy Board rebased and modified its AAM from a simple reliance on 75% of the change in the Canada Long Bond to 50% of the change in forecast long-term Canada bond yields and 50% of the change in observed A-rated utility bond index over the 30-year Canada Bond yield. The OEB continues to rely on its modified formula."

On page 11, the 2012 Concentric Update states"… if the Ontario formula were to be considered by the BCUC, we would recommend the formula be reviewed every three to five years."

117.1 Please indicate whether FBCU view that OEB's rebased and modified AAM formula is appropriate to determine a benchmark ROE in BC. Why or why not?

Response:

While the FBCU view the revised OEB formula as preferable to the prior formula used in BC, with a lower coefficient on the long Canada bond yield and the inclusion of a utility bond yield spread factor, the revised formula has not passed the test of time through varied market conditions. The FBCU view periodic rate determinations as a superior method for producing a fair return.

117.1.1 Please confirm that the OEB rebased and modified AAM formula does not have any provisions for Deadband, Ceiling/Floors, or Trigger Mechanisms.

Response:

Confirmed.

117.1.2 Should there be any Deadband, Ceiling/Floor, or Trigger Mechanisms if the Commission was to consider an ROE AAM in BC that is similar to

OEB's rebased and modified AAM formula? If so, what should those limits/triggers be set to and why?

Response:

The FBCU have not taken a position on whether deadbands, ceiling/floors or trigger mechanisms should be employed with an OEB type formula. Concentric evaluated these plan parameters in its A Review of Automatic Adjustment Mechanisms for Cost of Capital (November, 29, 2010) or the ("2010 Concentric Report"), and identified these mechanisms to "moderate or rebase the results of the formula in certain conditions" (page 12).

117.2 If the periodic rate proceedings are conducted every three to five years, do the FBCU believe that OEB's rebased and modified formula can withstand and meet the Fair Return Standard over this period of time?

Response:

It is premature to judge the ability of the revised OEB formula to meet the Fair Return Standard over time. The formula has only been in effect since December of 2009 for the setting of rates beginning in 2010 by way of a cost of service application. The OEB is rebasing electric and gas ROEs to the formula on a case by case basis.

As a general premise, the shorter the rebasing period, the greater the likelihood of the formulaic result meeting the Fair Return Standard.

117.2.1 In light of Canada bond yields and A-rated utility bond index, is there a min/max range of numerical inputs where the OEB rebased and modified AAM formula would work and meet the Fair Return Standard? Is there a range of numerical inputs where it would suggest otherwise? Please explain and specify.

Response:

It is not possible to determine a range of numerical inputs to the OEB formula that would meet the Fair Return Standard ("FRS"). As illustrated below from the OEB's May 1, 2012 Cost of Capital Parameter Calculations, there are three primary variables: the prior ROE, the change in long Canada bonds, and the change in the A rated utility bond yield spread. The only way to determine if the resulting ROE meets the FRS is to test the result against the three-pronged fairness test of comparability, financial integrity and capital attraction (please refer to the response to BCUC IR 1.117.3.1).

Step 4: Return on Equity (ROE) forecast

Initial ROE			9.75 %
Change in Long Canada Bond Yield Forecast from September 2009			
LCBF (January 2012) (from Step 3)	4	2.931 %	
Base LCBF		4.250 %	
Difference		-1.319 %	
0.5 X Difference			-0.659 %
Change in A-rated Utility Bond Yield Spread from September 2009			
A-rated Utility Bond Yield Spread (January 2012) (from Step 1)	2	1.479 %	
Base A-rated Utility Bond Yield Spread		1.415 %	
Difference		0.064 %	
0.5 X Difference			0.032 %
Return on Equity based on January 2012 data			**9.12 %**

117.3 Assuming that data for May to August 2012 are available, please calculate a benchmark ROE effective September 1, 2012 if the same OEB rebased and modified formula is used to determine the benchmark ROE in BC. Please show the detailed calculations and list any assumptions.

Response:

Concentric has recalculated the OEB rebased ROE as of the end of August, 2012 to be 8.96 percent. Our computations and assumptions are as follows:

Step 1: Analysis of Business Day Information in the Month

Month: August 2012

		Bond Yields (%)			Bond Yield Spreads (%)	
		Government of Canada		A-rated Utility	30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
Day		10-yr	30-yr	30-yr		
1	1-Aug-12	1.71	2.29	3.81	0.58	1.52
2	2-Aug-12	1.67	2.25	3.76	0.58	1.51
3	3-Aug-12	1.77	2.31	3.81	0.54	1.50
4	4-Aug-12					
5	5-Aug-12					
6	6-Aug-12			3.81		
7	7-Aug-12	1.84	2.37	3.89	0.53	1.52
8	8-Aug-12	1.82	2.35	3.86	0.53	1.51
9	9-Aug-12	1.81	2.33	3.84	0.52	1.51
10	10-Aug-12	1.78	2.32	3.82	0.54	1.50
11	11-Aug-12					
12	12-Aug-12					
13	13-Aug-12	1.80	2.33	3.82	0.53	1.49
14	14-Aug-12	1.85	2.37	3.86	0.52	1.49
15	15-Aug-12	1.95	2.46	3.93	0.51	1.47
16	16-Aug-12	1.96	2.49	3.95	0.53	1.46
17	17-Aug-12	1.94	2.48	3.95	0.54	1.47
18	18-Aug-12					
19	19-Aug-12					
20	20-Aug-12	1.94	2.48	3.96	0.54	1.48
21	21-Aug-12	1.92	2.47	3.95	0.55	1.48
22	22-Aug-12	1.84	2.41	3.89	0.57	1.48
23	23-Aug-12	1.82	2.40	3.88	0.58	1.48
24	24-Aug-12	1.83	2.41	3.88	0.58	1.47
25	25-Aug-12					
26	26-Aug-12					
27	27-Aug-12	1.80	2.38	3.86	0.58	1.48
28	28-Aug-12	1.80	2.36	3.82	0.56	1.46
29	29-Aug-12	1.80	2.37	3.84	0.57	1.47
30	30-Aug-12	1.77	2.34	3.82	0.57	1.48
31	31-Aug-12	1.77	2.34	3.79	0.57	1.45
		1.83	2.38	3.86	0.55	1.48
	Sources:	Bank of Canada		Bloomberg		

Step 2: 10-year Government of Canada Bond Yield Forecast

Source: Consensus Forecasts	Publication Date:	August 13, 2012			
		3-month	12-month	Average	
August 2012		1.800	2.300	**2.050**	%

Step 3: Long Canada Bond Forecast

10-Year Government of Canada Consensus Forecast (from Step 2)	2.050	%
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	0.551	%
Long Canada Bond Forecast (LCBF)	**2.601**	%

Step 4: Return on Equity (ROE) forecast

Initial ROE				9.75	%
Change in Long Canada Bond Yield Forecast from September 2009					
LCBF (August 2012) (from Step 3)	2.601	%			
Base LCBF	4.250	%			
Difference	-1.649	%			
0.5 x Difference				-0.825	%
Change in A-rated Utility Bond Yield Spread from September 2009					
A-rated Utility Bond Yield Spread (August 2012) (from Step 1)	1.485	%			
Base A-rated Utility Bond Yield Spread	1.415	%			
Difference	0.070	%			
0.5 x Difference				0.035	%
Return on Equity based on August 2012 data				**8.96**	%

117.3.1 If applicable, for the calculated benchmark ROE, do the FBCU believe this ROE meet the Fair Return Standard and is an acceptable benchmark ROE for this Proceeding?

Response:

As explained in the Companies' filing, based on the expert testimony of Ms. McShane and Dr. Vander Weide, the FBCU submits that the appropriate allowed ROE for FEI is 10.5%, based on a minimum of 40% equity thickness. The proposed ROE for FEI is based on a number of tests, including the discounted cash flow test, the comparable earnings test, and the equity risk premium test. Ms. McShane and Dr. Vander Weide support this proposal based on their detailed assessment of the current cost of capital. Based on a comparison to the result currently produced by the OEB formula of 8.96%, this is sufficiently below the FEI's proposed ROE of 10.5% to suggest that a review and rebasing of the formula might be required before it could satisfy the Fair Return Standard for FEI at this point in time.

117.3.2 Do the FBCU expect the benchmark ROE for January 1, 2013 to be similar to the September 1, 2012 ROE?

Response:

It is not clear to the FBCU what ROE's are being referenced in question above.

C. EXAMINATION OF THE RE-ESTABLISHMENT OF THE ROE AUTOMATIC ADJUSTMENT MECHANISM

118.0 Reference: ROE AAM

Exhibit B1-9 p. 27; Exhibit B1-9-5 RBC Capital Markets Data on Spreads

Fair Return Standard Requirement

The FBCU state that it has two main concerns with adopting a new AAM formula. First concern is that the shortcomings in the formula can yield a return that does not meet the Fair Return Standard. Second concern is that the efficiency benefits may be illusory.

118.1 Before the formula was eliminated in the December 2009 ROE Decision, it was in use since 1994/1995. In the view of the FBCU, are there years where the benchmark ROE calculated by the formula exceeded and years where the benchmark ROE falls short of the Fair Return Standard?

Response:

The FBCU do not believe that there are any years that the AAM resulted in a benchmark ROE that was higher than warranted by the fair return standard. In the FBCU's view, each time the AAM was reviewed and the benchmark ROE reset, the "going in" ROE was established at a level that was too low. The subsequent operation of the AAM in its various permutations, all of which had a high sensitivity to changes in long-term Canada bond yields exacerbated the problem, as long-term Canada bond yields persistently declined.

118.1.1 If the AAM could not provide a 'correct' ROE, what is a range of reasonableness?

Response:

The FBCU are of the view that the formula result should fall within a fairly tight band around the ROE that would be estimated using a "from first principles" approach, i.e., +/- 25 basis points. This, of course, assumes that the point of departure (i.e., the initial benchmark utility ROE) were fair.

118.2 In the table showing credit spreads for the period January 31, 2006 to May 31, 2012, it can be seen that during pre-January 31, 2008, spreads (bps) were below 155 and during 2007 it was as low as 115. Please comment if it is likely that in the days pre-2008 there was a mispricing of risk due to market exuberance which resulted in returns on common equity for a benchmark utility above the fair return standard?

Response:

With hindsight, there have been indications that risk was mispriced prior to the financial crisis across a broad range of securities, i.e., investors did not require a high enough risk premium for the fundamental risk to which they were exposed. The fact that credit spreads were relatively low in 2006 does not provide any insight into whether the allowed ROE was too high or too low. In fact, it was in that time frame that Karen Taylor and Michael McGowan, utility analysts for BMO Capital Markets concluded that, "We believe on a collective basis, that the allowed returns as established by the formulas highlighted above are confiscatory and likely violate the Fair Return Standard." (BMO Capital Markets, *Pipelines & Utilities: 2007 ROEs Decline to Unprecedented Levels*, December 7, 2006) The formulas "highlighted above" included the BCUC AAM.

118.2.1 Does an AAM which produce results within a range of reasonableness, properly track the market sentiment?

Response:

Market sentiment, which is a gauge of whether investors are bullish or bearish, can change very rapidly. It may have no bearing on the underlying fundamental determinants of the cost of equity. A reasonably constructed AAM need not, nor is it likely to be able to, track market sentiment.

119.0 Reference: Testimony of Ms. Kathleen McShane

Exhibit B1-9-6 Appendix F, pp. 31- 33

Automatic Adjustment Formula

Ms. McShane analyzed that the earnings yields, the inverse of the P/E ratios, provide a rough guide to the direction in the market cost of equity in the period 2009 to the present. She opined that while the Government of Canada bond yields have declined significantly between late 2009 and mid-2012, the corresponding implication is that the equity market risk premium is higher currently than it was in late 2009.

Ms. McShane observed that since the beginning of 2008, the ratio of utility dividend yields to long-term Canada bond yields has risen markedly.

Ms. McShane is of the opinion that in light of the persistently unsettled capital markets and the unstable relationships between the utility cost of equity and Government bond yields, it would be difficult to construct an automatic adjustment mechanism for return on equity at this time that would successfully capture prospective changes in the utility cost of equity. In particular, an automatic adjustment formula tied to changes in government bond yields has the potential to unfairly suppress the allowed ROE.

119.1 Is the unstable relationship between Canadian utility dividend yields and long-term Government of Canada bond yields as observed by Ms. McShane a temporary phenomenon?

Response:

Ms. McShane does not know whether it is a temporary phenomenon. She would expect that, as long-term Canada bond yields rise to more normal levels, the relationship between utility dividend yields and long-term Government bond yields would revert to a relationship that more closely resembles what was observed before the onset of the financial crisis. However, when that might occur is uncertain, as low government bond yields are expected to persist for an extended period of time.

119.1.1 If the unstable relationship persists, would a new AAM that incorporate utility bond yields and Canada bond yields as variables produce more reasonable benchmark ROEs?

Response:

Ms. McShane's response is premised on the assumption that the question was asking about a formula including government bond yields and utility dividend yields, as that was the subject of the discussion in BCUC IR 1.119.1. In current markets, Ms. McShane questions the potential accuracy of any formula that includes government bond yields. Theoretically a formula might be developed that includes utility bond and dividend yields. However, given the small number of publicly-traded utilities in Canada, a formula including utility dividend yields could potentially produce erroneous results due to changes in company-specific circumstances that are unrelated to changes in the cost of equity to utilities generally.

120.0 Reference: Evidence of Concentric Energy Advisors and FBCU

Exhibit B1-9-6 Appendix I, p. 13 (2012 Concentric Update); Exhibit B1-9, p. 28

Periodic Rate Hearings and Regulatory Efficiency

On page 13, the Concentric Update concludes that periodic rate case determinations remain the method most likely to produce fair returns over time under varied market circumstances.

Section 60(1)(b) of the Utilities Commission Act states that:

> (b) the commission must have due regard to the setting of a rate that
>
> (i) is not unjust or unreasonable within the meaning of section 59,
>
> (ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and
>
> (iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

120.1 Please comment on whether the analysis and conclusion from Concentric considers the requirements of the Commission's mandate set out in subsection b (i) and b(iii) above. If so, please outline the considerations in each subsection. If not, why not?

Response:

Concentric's recommendations primarily address whether a formulaic ROE could continue to satisfy the Fair Return Standard over time and under varied market conditions. We do, however, consider regulatory efficiency and costs in the design criteria outlined on pages 7-8 in the updated report. As such, Concentric's recommendations would address requirements (i) of the Commission's mandate, and part (iii) as it relates to efficiency and reduced costs.

Concentric is of the view that litigated rate proceedings where company and stakeholder witnesses present independent ROE estimates, and the Commission weighs the evidence and determines the fair ROE, provide the best opportunity for a fair return determination to be made that is responsive to market conditions and factors in stakeholders' considerations.

Concentric is mindful of the potential efficiency of a formula, but concludes periodic rate proceedings are more likely to produce a fair return.

120.2 Please discuss whether Concentric's conclusion for periodic rate case determinations for ROE considers the incremental regulatory costs required and ultimately burdened on ratepayers. Please explain whether this incremental regulatory cost is consistent with section 60(1)(b)(iii)?

Response:

Concentric has listed the advantages and drawbacks to periodic rate cases on page 12 of its updated, August 2012, Report, where the incremental regulatory cost was considered as a drawback. This incremental regulatory cost is justified if it is necessary to achieve the Fair Return Standard. Concentric notes that large generic proceedings to review the cost of capital formula are also expensive and may outweigh the cost of individual rate cases. On balance, we believe the recommendation of periodic rate proceedings, every 3-5 years, does satisfy the requirement of 60(1)(b)(iii).

The FBCU state "While regulatory efficiency is an appropriate consideration, achieving a return that meets the Fair Return Standard is always the paramount obligation.

Second, the efficiency benefits may be illusory. The AAM in use previously was adopted in 1994, and over the 15 year period, there were regular reviews and adjustments with the AAM in part due to concerns that the ROEs produced were not meeting the Fair Return Standard. So while efficiency was intended, it is not clear that the ultimate goal was achieved."

120.3 Would the FBCU please substantiate the above statements by providing the following:

a) An estimate of the costs expended by the FBCU on this proceeding to date, including FBCU staff time, legal counsel and expert witnesses

b) An estimate of the total future costs to the FBCU for the IR process, hearing process and follow-up

c) An estimate of Registered Interveners costs including their experts.

d) An estimate of Commission-related costs including staff time, Commissioners time, Commission Counsel and consultants' time.

Response:

The requested estimates follow:

a) An estimate of the costs expended by the FBCU on this proceeding to date, including all external costs for legal counsel, experts, and courier costs are approximately $173,000. Internal staff time costs are part of O&M, and therefore, no additional expenses are incurred.

b) An estimate of the total future costs to the FBCU for the remainder of the regulatory review process are approximately $900,000.

c) An estimate of Registered Intervener costs based on the PACA Budgets filed with the Commission is approximately $455,000.

d) An estimate of the Commission-related costs, provided by Commission staff is approximately $500,000. It is the understanding of the FBCU that this amount is an apportionment of the Commission's quarterly levies (pursuant to Commission Order No. G-52-12) for which all utilities are charged, and therefore, the FBCU do not expect any additional invoices for Commission-related expenses.

There is no question this GCOC is a costly and time consuming exercise. The point that the FBCU are making in the quoted passages is that reviews of the old AAM were undertaken during the period it was in effect, i.e. the presence of the formula did not do away with the need for detailed reviews. Not only were the parameters of the mechanism adjusted as a result of these reviews, but also rebasing occurred. On the whole, were a new AAM implemented it would still have to be reviewed periodically. The primary difference from an administrative perspective between having an AAM and not having one is that an AAM results in annual adjustments between those reviews rather than maintaining the same ROE and capital structure between those reviews as the FBCU are proposing. As such, efficiency benefits with the AAM should not be overstated.

121.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 7 (2012 Concentric Update)

Formulaic Adjustment Mechanism Design Considerations

On page 7 of the Concentric Update, Concentric states that "A formulaic ROE that can be readily estimated by stakeholders promotes regulatory transparency, enabling investors to make forward projections based on widely understood data inputs."

121.1 Is an ROE that is set by frequent cost of capital or rate hearings more or less able to enable investors to make forward projections? Why?

Response:

Concentric acknowledges that some level of predictability is lost by introducing litigation to the process for ROE determinations.

122.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 8 (2012 Concentric Update)

Formulaic Adjustment Mechanism Design Considerations

On page 8 of the Concentric Update, Concentric elaborates on its seventh design criterion "Insulated from the Effects of Anomalous and Transitory Market Conditions."

122.1 Is an "off ramp" from the formula when economic or market conditions become too unstable a suitable way to meet this criterion?

Response:

Yes. The implication of the referenced section is that a review will be triggered if the ROE exceeds a set ceiling or floor.

122.2 To what extent does, or can, the eighth criterion – "Specified Timetable for Periodic Review and/or Rebasing of the Formula"--create such off ramp and therefore satisfy the preceding criterion ("Insulated from the Effects of Anomalous and Transitory Market Conditions")?

Response:

Provided that conditions are established which would trigger a review and/or rebasing of the formula in the event of anomalous market conditions or concern that the formula is producing unreasonable results, (the eighth criteria "Specified Timetable for Periodic Review and/or Rebasing of the Formula)," the criterion, "Insulated from the Effects of Anomalous and Transitory Market Conditions," would be satisfied.

123.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 10 (2012 Concentric Update)

Formulaic Adjustment Mechanism Design Considerations

On page 10 of the Concentric Update, it states that "An AAM should be sufficiently robust to function in varied and extreme market conditions".

123.1 Is there an optimal time period over which an AAM should demonstrate such robustness? If an ROE is rebasing or re-set every 3-5 years, then can the formula be adjusted at that time if required so that robustness only needs to be sufficient for one business cycle (or perhaps less)?

Response:

To establish reliability, a formula should demonstrate robustness under a variety of market conditions. An ROE that does not meet the fair return standard for any period of time, i.e. even less than 3 to 5 years does not meet the Fair Return Standard. However, utility management may find it desirable to establish a fixed return over a three to five year period if they are assured of a rebasing to a fair return at the end of the three to five year period. This would depend on the circumstances and inclination of utility management and approval by the regulator and agreement from stakeholders. Concentric considers it prudent, at the end of each three to five year period, to review the formula against other ROE methodologies and against recently awarded ROEs to verify that the fundamental relationships upon which the formulaic model is based, remain intact.

124.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 12 (2012 Concentric Update)

Potential Approaches

On page 12 of the Concentric Update, Concentric submits that foremost among the challenges associated with the design and implementation of an ROE formula, is the dynamic nature of financial markets and the potential change in equity costs for the benchmark utility in relation to the broader industry.

124.1 If an ROE based on a formula was rebased every 3-5 years, would these challenges be more or less significant for an ROE that was set after a hearing for a period of 3 years without adjustment?

Response:

It is impossible to say with certainty, and would depend on how the formulaic inputs respond directionally to market conditions. In theory, if the assumptions upon which the formula is based continue to hold, we would expect the formulaic result to be less subject to the challenges of dynamic market conditions than a fixed ROE. One of the practical problems with a formula, however, is the reluctance to change once adopted as cited by Major and Priddle in their evaluation of the formula used in Canada: "its mechanistic character suspends for lengthy periods the previously-valued application of informed judgment to the results of alternative methods of achieving the FRS required by Canadian jurisprudence in ROE awards." (Please refer to the response to BC Util Cust IR 1.2.4)

125.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9 p. 4; Exhibit B1-9-6, Appendix I, p. 10 (2012 Concentric Update)

AAM Methodology – Relevance to Current Economic Conditions

On page 4 of Exhibit B1-9, the FBCU state "The primary basis for the 2009 Application was that the allowed ROE of 8.47% and equity thickness of 35.01% failed to meet the Fair Return Standard, and that the AAM was broken… There was a reasonable prospect that the AAM, which was tied to Government of Canada long bond yields, would soon yield an ROE below 8%. The financial crisis of 2008 thus influenced the timing of the Application but it was not the sole basis for the 2009 Application."

Page 10 of the Concentric Update states "… during the 2008-2009 financial crisis, a formula that is heavily weighted on a single factor may be unduly influenced by market events. During the financial crisis and economic recession, credit spreads widened significantly and equity market volatility rose to unprecedented levels, ultimately causing government bond yields and corporate capital costs to move opposite to one another despite a historical positive relationship… Common equity holders are exposed to higher risk than bond holders, and both classes of investment are subject to market circumstances (e.g., the flight to safety lowering government bond yields) that may impact that security but not the other."

125.1 Concentric Update attributes the broken formula to, in parts, the government bond yields and corporate capital costs moving in opposite direction despite a historical positive relationship. Do the FBCU believe that regulated utilities in BC should be unaffected by the volatility of fluctuating Canadian bond yields over time? Please explain.

<u>Response:</u>

The FBCU do not believe that the Concentric position as paraphrased in the question above suggests that regulated utilities should be unaffected by volatility of Canadian bond yields. FBCU believes the point being made by Concentric is that the change in government bond yields was driven by factors that did not reflect the cost of equity of a utility and to rely on government bond yields led to allowed ROEs below what constitutes a fair return. The fair return standard should be met consistently.

125.1.1 Do the FBCU believe that the benchmark ROE for regulated utilities in BC should reflect economic cycles (e.g. lower ROEs during economic recessions and higher ROE during expansions)? Please explain.

Response:

The FBCU is of the view that that the factors impacting the determination of the ROE may change, but in the aggregate the ROE should be established to meet the Fair Return Standard, and not necessarily change based on the economic cycle. As part of determining the ROE, factors such as economic conditions, market conditions and capital market conditions are considered, and those factors will inherently reflect economic cycles, but the nature of the economy, be it recession or expansion, should not directly determine the ROE.

125.1.2 In a recession, the overall market may experience relatively low returns. Should investors in regulated utilities be immune from a lower rate of return that is reflective of the recessionary market? Why or why not?

Response:

Typically in a recession, investors will perceive greater risk and demand a higher return across the market and as such, the market risk premium or premium to hold equity securities will increase not decrease. Regulated utilities must continue to have access to capital in all markets as they provide critical services and it's for this reason that the return performance of a Utility is meant to equal the return demanded by its investors in any market. While many non-regulated businesses will experience a decrease in their actual performance as suggested in the question, the returns demanded by investors to own an interest in those businesses will increase substantially.

126.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 11 (2012 Concentric Update), p. 26 (2010 Concentric Report)

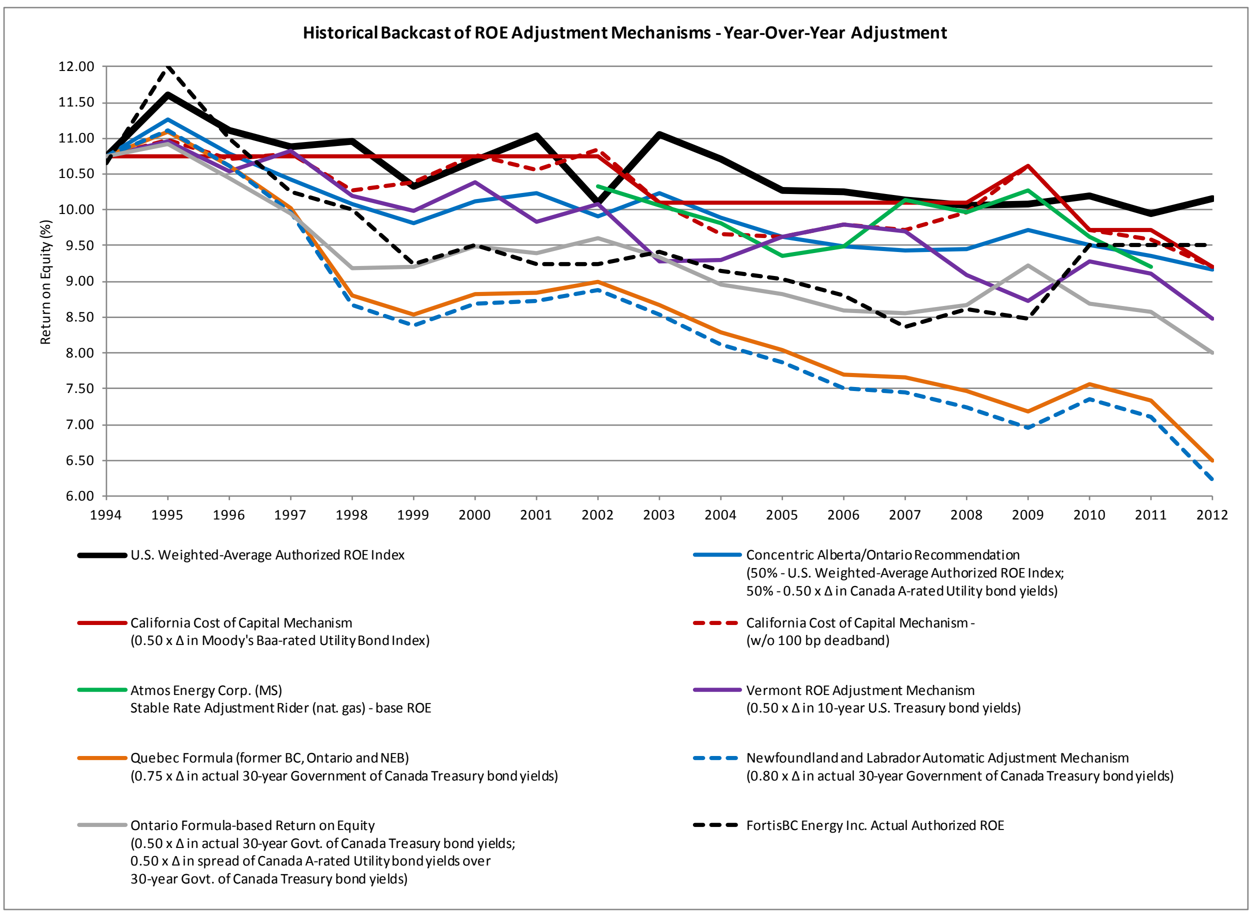
Backcast Analysis

On page 11 of the Concentric Update, Concentric discusses the use of a backcast analysis on nine alternative formulas. Page 26 of the 2010 Concentric Report shows the results of the backcast analysis.

126.1 Please update Figure 4: Backcast Analysis to reflect the latest data and provide the accompanying dataset for the Figure.

Response:

Figure 4, is reproduced and updated below. The data set is included in Attachment 126.1.



126.2 Do the backcasted alternatives with a poor fit to the Terasen Gas Inc. (as FEI was formerly known) Actual Authorized ROE necessarily reduce the desirability of those alternatives in the future? Why or why not?

Response:

Yes. Formulaic alternatives that have already proven to be flawed should be avoided as it is known that those formulas have produced results that do not meet the fair return standard.

127.0 Reference: Evidence of Concentric Energy Advisors Inc.

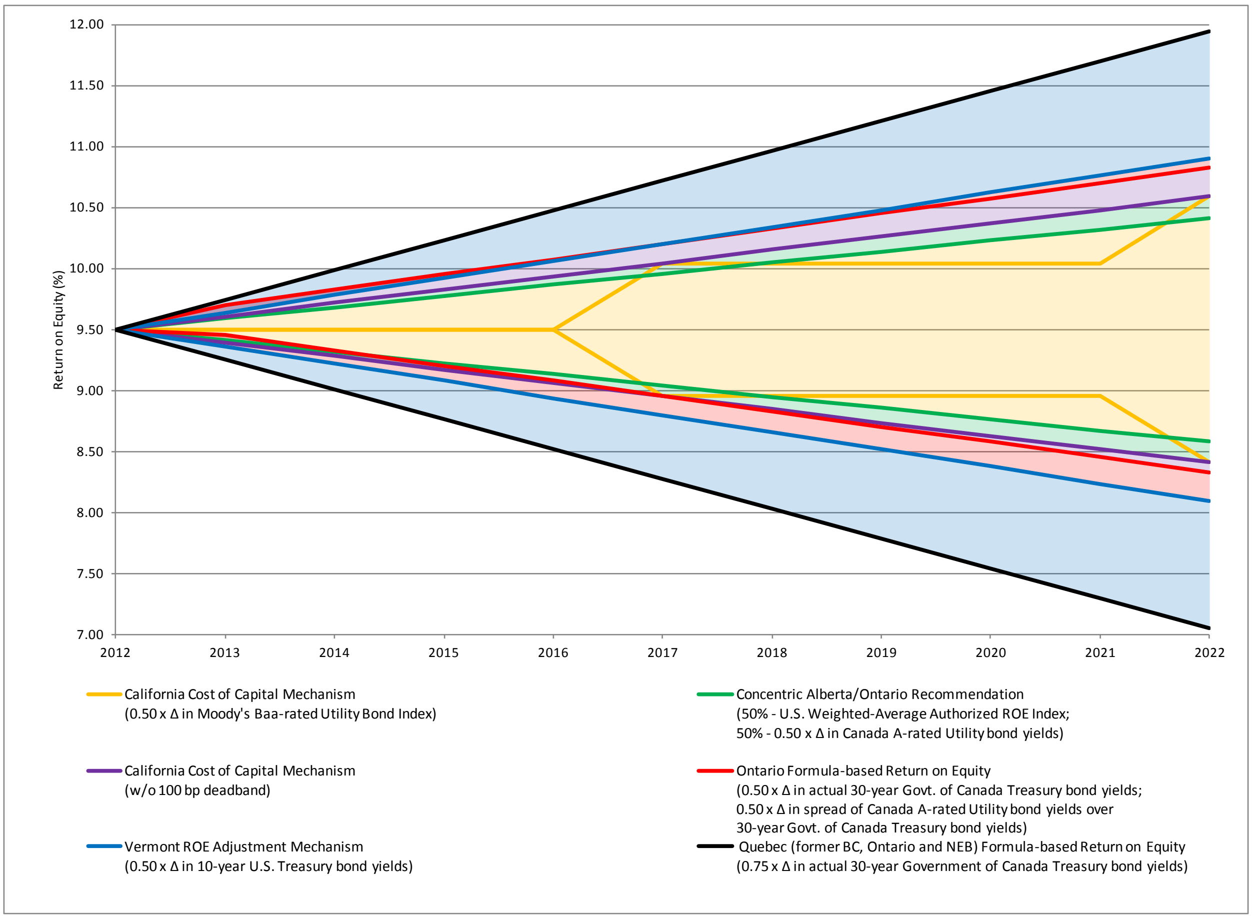
Exhibit B1-9-6, Appendix I, p. 47 (2010 Concentric Report)

Examination of the ROE AAM

On page 47of the 2010 Concentric Report discusses the use of stress tests for a formulaic approach.

127.1 Please provide an update of the stress tests given current 2012 market conditions.

Response:



128.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 1 (2010 Concentric Report)

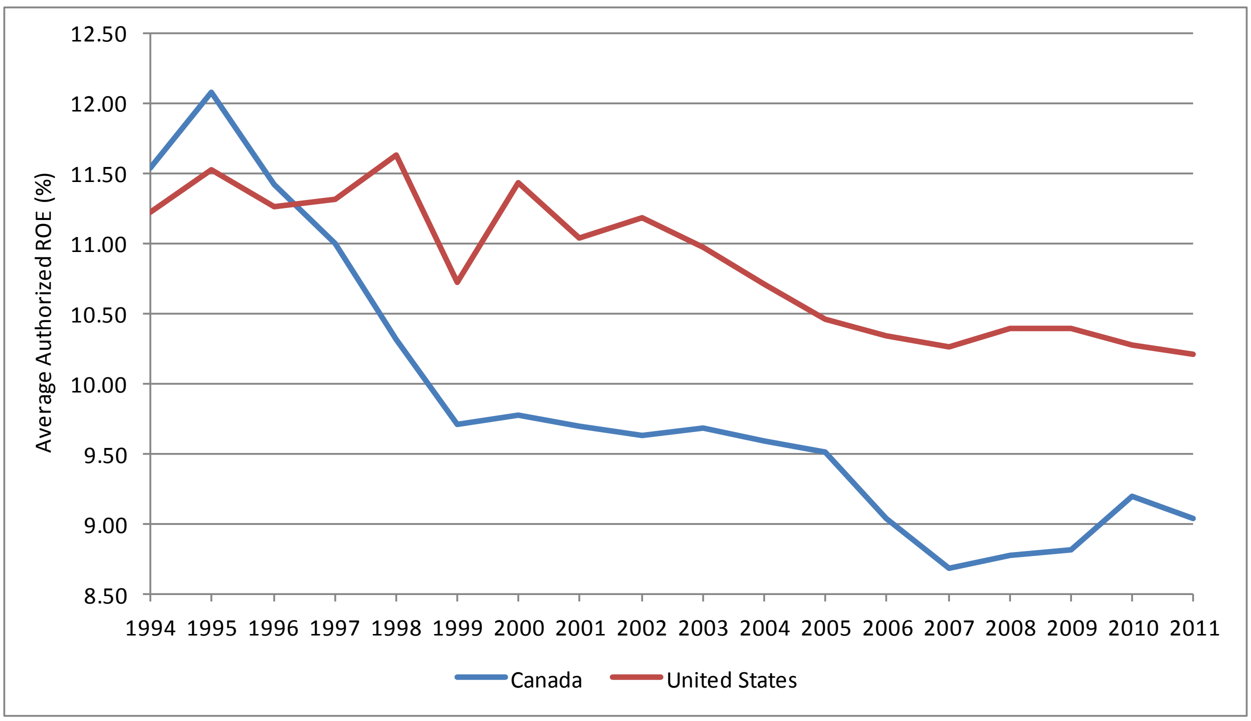
Comparative Canadian and U.S. Utility Equity Returns

On page 1 of the 2010 Concentric Report states that "Over the period since implementation of the AAM, Canadian utilities that were receiving ROEs in parity with the U.S., were receiving ROE awards 200 basis points lower than their U.S. counterparts."

128.1 Please provide the date showing the relative ROEs between Canadian and U.S. utilities, and the period(s) when the ROEs were at parity.

Response:

The below figure charts average U.S. ROEs versus those authorized for the Canadian utilities. As the figure indicates, U.S. and Canadian ROEs moved in tandem within 50 bps from 1994 to 1996, but began to diverge in 1997.



129.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 6 (2010 Concentric Report)

Comparative Canadian and U.S. Utility Equity Returns

On page 6 of the 2010 Concentric Report states that "…there are a handful of U.S. jurisdictions that fix ROE at a specified rate and do not make adjustments, but rather share overages and shortfalls with ratepayers."

129.1 Even in those instances is it still not necessary to determine a fair return in order to calculate the overage or shortfall? If not what is the base from which it is calculated?

Response:

Agreed. It is still necessary to determine a fair return upon which the overage or shortfall is calculated.

130.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 12 (2010 Concentric Report)

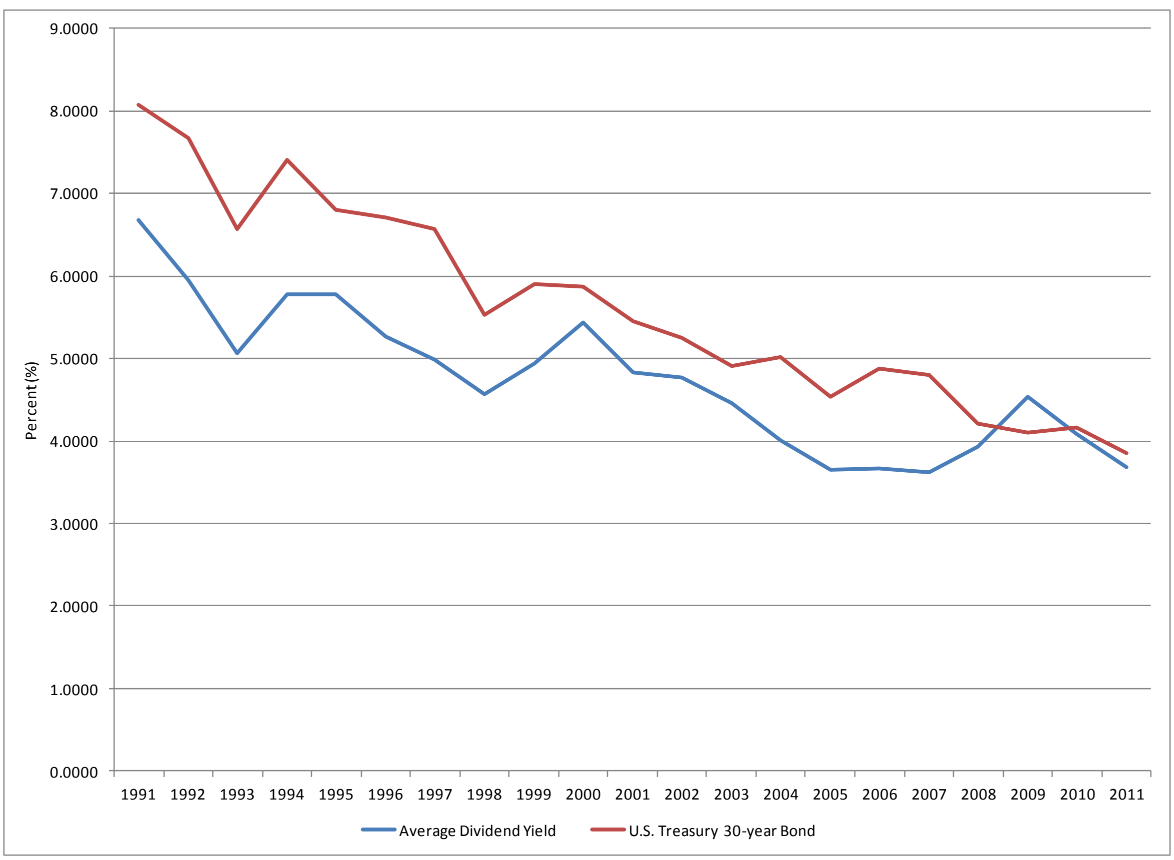
Alternative Formulaic Approaches

On page 12of the 2010 Concentric Report reproduces Figure 2 from its 2007 Report for the OEB and states that the figure shows a "…strong positive relationship between average annual 30-year U.S. Treasury yields and the average annual dividend yields for a representative group of U.S. gas distribution utilities."

130.1 Since the 30-year bond yield is consistently above the dividend yield by approximately 0.5 to 1.5 yield percentage, would Concentric consider the 30-year treasury yield to be a suitable upper limit for the growth estimates in the DCF test? If not, why not?

Response:

No. In 2009, the 30-year Treasury yield dipped below the average dividend yield and has recently been near parity. Below is an updated chart for current data, based on Bloomberg data for the universe of Value Line natural gas distribution utilities.



131.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 28 (2010 Concentric Report)

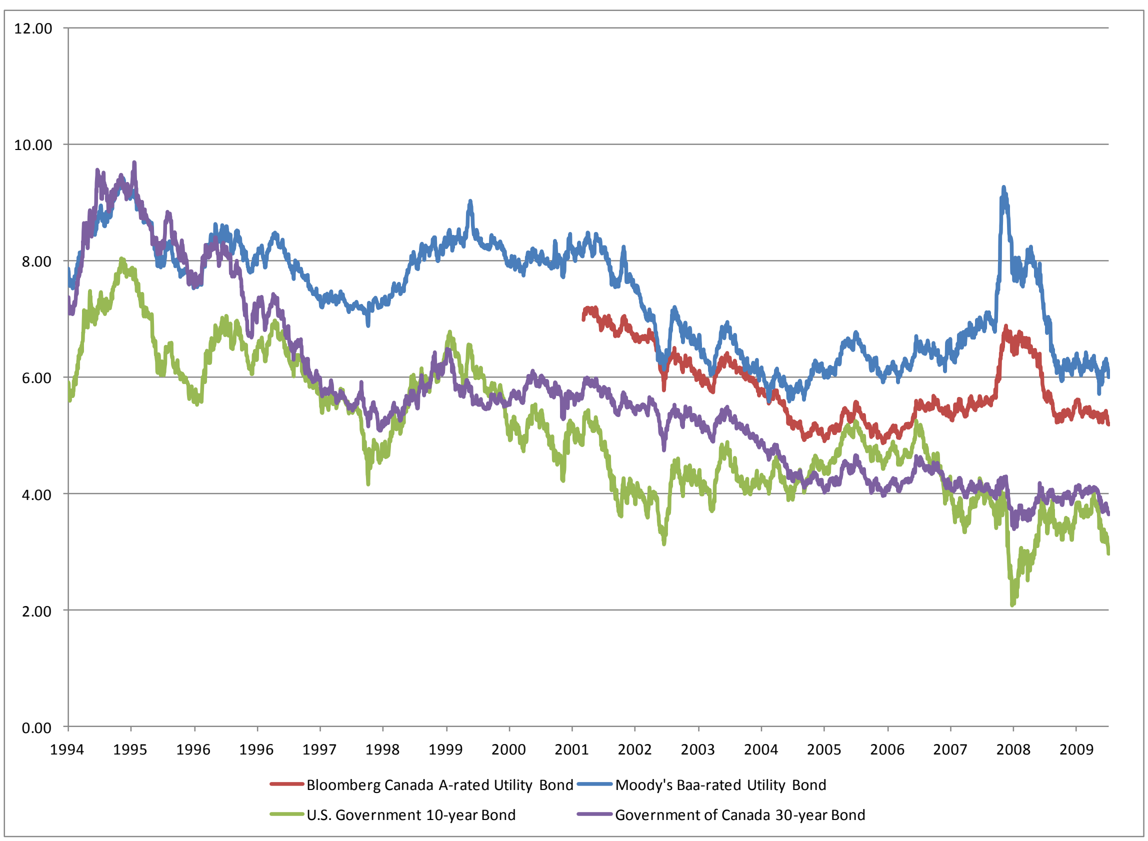
Alternative Formulaic Approaches

Referring to the Table 3 titled Descriptive Statistics (January 1, 1994 - June 30, 2010) on page 28 of the Concentric Report dated November 29, 2010 (2010 Concentric Report), Concentric states that: "The variability in U.S. ROE decisions is the lowest within the sample of formula inputs…"

131.1 Can Concentric say if the direction of interest rates and bond yields over the same period was consistently rising or falling, and if so, in which direction were they moving?

Response:

As the figure shows, bond yields have generally been trending downwards since 1994. The divergence between corporate credit and government credit since 2007 can be attributed to government monetary policy initiatives and the flight to quality in the global financial crisis, when default risk rose influencing corporate credit yields upwards while government bond yields were declining.



131.2 To what extent does the low variability in U.S. ROE decisions reflect that litigated ROE cases are relatively insensitive to market changes?

Response:

Concentric provided a measurement of the sensitivity of U.S. ROE decisions to changes in interest rates at Table 1 on page 13 of the 2010 Concentric Report. Concentric disagrees that litigated ROE cases are insensitive to market changes, but would instead attribute the lower variability in litigated ROEs, when compared to the variability of government or corporate bond yields, to the regulator's consideration of a multitude of factors (including market changes) in the evidence of the proceeding that are not adequately represented by the simple movement of bond yields from one period to the next.

131.3 To what extent is using this as an input circular?

Response:

Concentric does not consider the use of U.S. ROE decisions as an input to Canadian ROE decisions to be circular. Though Concentric would not expect Canadian regulators to base their ROE determinations entirely upon U.S. data, Concentric does believe that U.S. data provides a good check to be sure that the ROE is directionally aligned with litigated North American ROE determinations. This could serve as a directional input to the formula itself, or as an off ramp, should the formula diverge substantially from U.S. allowed returns. Concentric would consider this data to be circular only if U.S. regulators relied on Canadian ROE decisions to make their ROE determinations. This is currently not the case. Currently, the majority of U.S. ROE decisions are based upon proxy groups pulled from the vast number of electric and natural gas distribution utilities in the U.S.

132.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9 pp. 28-29; Exhibit B1-9-6, Appendix I, pp. 39-45 (2010 Concentric Report)

ROE AAM as Alternative – Concentric Recommendation

On pages 28 and 29 of Exhibit B1-9, the FBCU state "… if the Commission requires a ROE AAM as an outcome of this Proceeding, the Commission should at a minimum seek to rectify some of the most problematic elements of the old formula. Any new formula would need to introduce new factors that would address changes in utility equity risk premium, not solely changes in Government of Canada bond yields, and any adjustment factor would need to reflect the sensitivity to change in bond yields to ROE."

Starting on page 40 of the 2010 Concentric Report, Concentric provides the following formulaic methodologies:

(1) Utility Bond Yield Index

(2) Utility Bond Yield Index with a Deadband and Trigger

(3) Combined Utility Bond Yield and Average Awarded ROE Index

(4) Multiple Method Model

132.1 If the Commission considers an ROE AAM, do the FBCU prefer a particular methodology as provided by Concentric?

Response:

Please refer to the responses to BCUC IRs 1.113.1 and 1.113.2.

132.2 With respect to the Utility Bond Yield Index method, Concentric submits that the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond yield and the DEX alternative move in close proximity, and either should be a reliable indicator of long-term Canadian utility bond yields.

Response:

Concentric does not have access to the DEX series and thus can only provide insight on the basis of information provided to us by third parties. However, we note the features (as we understand them) to be the following:

Bloomberg FV Canada 30-Year A-Rated Utility Bond Index	DEX Long Term Energy Index
• Includes global financial data including U.S. and Canadian data. • Data specific to utilities is accessible by credit rating and term of security. • Extrapolates bond yield data for various maturities by use of a fair value methodology which plots current YTM of outstanding A-rated Canadian utility bonds and derives other points along the fair value curve for differing maturities. • Substantial platform for all aspects of global financial and commodities markets. • Transparency of component companies included in index • Requires a substantial investment in Bloomberg subscription. • Stringent data protection requirements	• Sole Focus on Canadian fixed income market • May select sub index (energy) from corporate bond market. • Comprised of all Canadian energy sector bonds with maturities in excess of 10 years. • Data series not subdivided by credit rating. • Based on actual bond market prices and does not include a fair market value extrapolation. • Component companies included in the index are proprietary and are disclosed only as a snap-shot of constituents for a fee of approximately $2,500. • Highly proprietary. Stringent data protection requirements. "No part of this may be reproduced or transmitted in any form by any means without prior written permission... The information contained herein may not be redistributed, sold or modified or used to create any derivative work without the prior written consent of TSX Inc." • Data is provided in hard copy on a monthly basis. • Requires a moderately expensive fee for annual subscription.

Please compare and contrast the features of the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond Index and the DEX Long-Term Energy Index (as mentioned in Figure 13, p. 39 of the 2010 Concentric Report).

132.2.1 Please confirm that the "DEX alternative" that can be used in the Utility Bond Yield Index method refers to the DEX Long-Term Energy Index. If not confirmed, please clarify.

Response:

Confirmed. However, Concentric believes the long-term corporate A index would also provide a reasonable proxy for Canadian utility bond yields.

132.2.1.1 Please provide similar analysis as shown in *Appendix A – Formulaic Inputs* for the DEX alternative (or DEX Long-Term Energy Index).

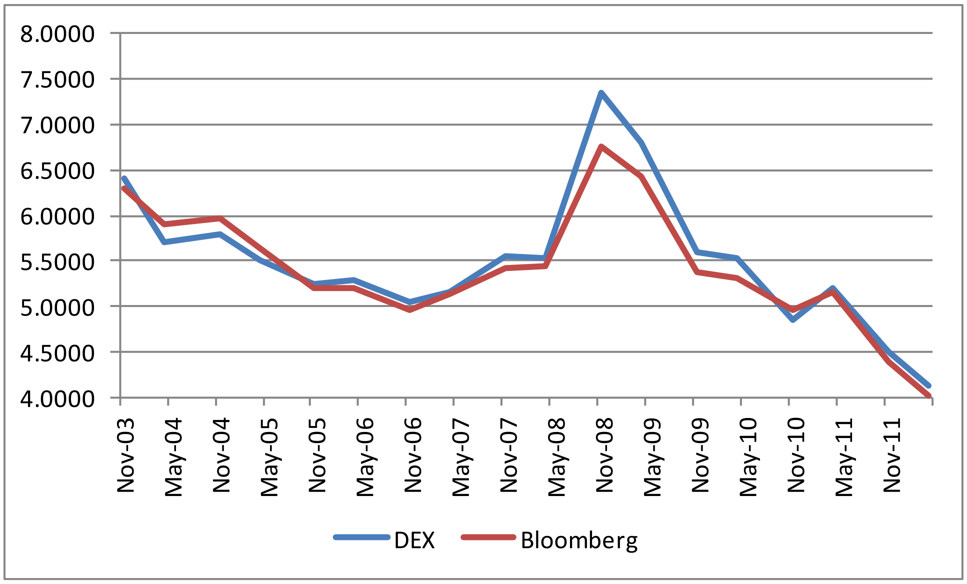
Response:

INPUTS	ADVANTAGES	DISADVANTAGES
DEX Long Term Energy Index	• There is a historical relationship between corporate utility bond yields and utility authorized equity returns. • Less impacted by government monetary policy and broad macroeconomic trends. • Sole focus on Canadian fixed income market • May select sub index (energy) from corporate bond market. Sub indexes were first created in 2003 so there is limited history. • Comprised of all Canadian energy sector bonds with maturities in excess of 10 years. • Data series not subdivided by credit rating. • Based on actual bond market prices and does not include a fair market value extrapolation.	• Requires a significant investment for DEX subscription. Annual costs estimated at approx. $3.500/year • Data series not subdivided by credit rating. • Highly proprietary. Allowed uses of data are limited to use in analysis. Stringent data protection requirements • Not forward looking (historical data) • Will not necessarily reflect effects of changes in equity markets. • Bond maturities will range from 10 and over years, i.e. no differentiation between a 10+ year bond and a longer term bond.

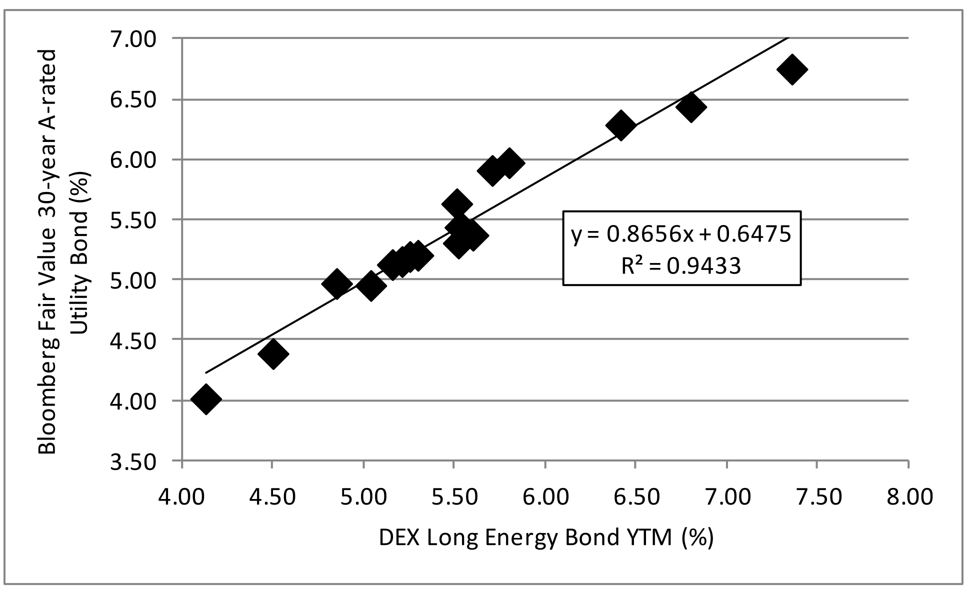
132.2.2 Please demonstrate (include R2 statistics) that the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond yield and the DEX alternative move in close proximity. Please show from 1990 to present.

Response:

The figure below reflects that the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond yield and the DEX alternative move in close proximity. Below is a chart of historical bond yields for each series since the DEX first became available in 2003.



The below figure, demonstrates the statistical historical relationship between the two price series. The Bloomberg Fair Value 30-year A-rated Utility Bond % is the dependent or "y" variable, and the DEX Long Energy Bond YTM is the independent or "x" variable.



132.2.3 Are there any reasons to choose Bloomberg over DEX for a utility bond index for the purposes of an ROE AAM formula?

Response:

The primary benefit of the Bloomberg series is that it provides bond data specific to Canadian regulated utilities for a specified credit rating. Because it is derived by extrapolating points along the fair value curve for differing maturities, there is a data point for each desired maturity, i.e. 25 years, 30 years, etc. The DEX long term energy index does not differentiate by credit rating, is not specific to regulated utilities, and includes any eligible bond with maturities exceeding 10-years in the long term index. However, a primary benefit is that the sole focus of the platform is on the Canadian bond market and actual yields to maturity are quoted as opposed to yields derived by the fair value curve, as is the case with Bloomberg. Further, DEX appears to be more restrictive in the use of its data. Though Bloomberg is also highly restrictive in the use of its data, it appears to be less so than DEX. The primary drawback of Bloomberg is the cost.

132.2.4 Please clarify the difference, if any, between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond yield and the Bloomberg historical 30-Year A-rated Utility Bond Yield (as shown in *Appendix A – Formulaic Inputs*). Which one should be used in the Utility Bond Yield Index method?

Response:

They are one and the same, and were only notated differently by Concentric in its Report.

132.2.5 Should the ROE AAM consider both U.S. and Canadian Utility Bond Yields, or only Canadian Utility Bond Yields? Please explain.

Response:

Because Canadian bond yield data is available, Concentric would suggest using Canadian bond yields. However, if it were deemed impractical to subscribe to a service that provided Canadian bond yield information, Moody's data is relatively inexpensive and is reasonably correlated with Canadian bond yields. If the BCUC were to use Moody's data, which is heavily weighted towards U.S. utilities as an input to its formula, Concentric recommends periodic checks to be sure that correlations remain highly positive.

132.2.6 How would the Utility Bond Yield Index method differ if 30-Year Canada long bond is included? Please show numerical example(s) and list the assumptions.

Response:

If a 30-Year Long Canada Bond Yield is included, Concentric would suggest that the BCUC include some measure of the recent spread between government and utility 30-year bonds. Ontario has adopted such a formula, whereby a 10-year government bond yield is forecast for the upcoming year, plus the spread between 10 and 30 year bonds to arrive at a forecast of 30-year bond yields. To that forecast, the credit spread between 30-year, A-rated utility bonds and 30-year government bonds is added. The formula sensitivity is set at 0.50, such that any change in government bond yields and/or credit spreads increases ROE by half of the respective change. For example, the basic model is:

$$ROE_n = ROE_{benchmark} + 0.50 \times (LCBF_t – LCBF_{benchmark}) + 0.50 \times (Average\ Credit\ Spread_t – Average\ Credit\ Spread_{benchmark})$$

Where LCBF = the Long Canada Bond Forecast, calculated by taking the average of the Consensus Forecasts, 3 months and 12 months out and adding to that result the average daily spread between 10-year and 30-year long Canada bond yields for the prior month; and

Where Average Credit Spread = the daily average of the differences between the 30-year bond yield (as published by Bank of Canada) and the Bloomberg A-rated Utility Index.

So, if the starting ROE (n-1) is 9.5%, and the forward looking long Canada bond yield estimate increases from 5% to 8%; and the credit spread decreases from 1.5% to 1%, the new ROE is:

ROE = 9.5 + 0.5*(8.0 – 5.0) + 0.5*(1.0 – 1.5) = 10.75%

Concentric sees the only advantage of separating the formula into two components (government bond yield and credit spread) to allow for the incorporation of a forecast of the 30-year bond yield while using near term historical data for yield spreads. Otherwise, the Commission could rely entirely on near term historical data for the utility bond yield. Concentric sees merit in using a forward-looking element in the formula, but, there is some risk that forecast bond yields and historical bond spreads may not move in accordance with their historical relationships and formulaic results may be skewed inappropriately.

132.3 With respect to the Utility Bond Yield Index with a Deadband and Trigger method, Concentric recommends a Deadband: 50 basis points and Trigger Mechanism: 100 basis points. Please confirm these two thresholds are appropriate to be applied across all regulated utilities in BC. If not confirmed, please explain otherwise.

Response:

Concentric cannot confirm. These parameters were used in Concentric's 2010 Report for purposes of evaluating alternative formulaic approaches. The purpose of the analysis was not to determine their appropriateness across all regulated utilities in BC.

132.3.1 Please explain the merits to set a (i) 50bps Deadband and (ii) 100bps Trigger Mechanism.

Response:

Concentric has not recommended a formula for FortisBC; nor has it recommended a specified level of deadband or trigger mechanism. The 50 bps deadband and 100 bps trigger mechanisms were offered as examples of what may be considered useful by the Company and its stakeholders. Arriving at an appropriate level for the deadband is dependent on the willingness of the company, the regulator, and the ratepayers to accept the potential cost of the deadband against the benefits of stable and transparent rates and reduced administrative burden for the rate change. If a deadband is applied in BC, it should be the product of stakeholder consultations. This deadband may be set at as an absolute, e.g. only change ROE if there is greater than a 50 bps change in bond yields or as a relative measure, e.g. only change ROE if there is greater than a 10% change in the bond yield.

As Concentric indicated in its Reports, trigger mechanisms provide off ramps to keep the formula from diverging too far from a fair return. In Concentric's example, we proposed a trigger mechanism that was tied to North American litigated ROE proceedings. We believe that Canadian ROEs that diverge by greater than 100 bps from North American ROEs are suspect and should be reviewed expeditiously. However, Concentric has not recommended an absolute threshold for a trigger mechanism and if the Commission determines that a trigger mechanism would be useful, Concentric would encourage the Commission to derive the specifics of the mechanism after consideration of stakeholders' views.

132.3.2 By implementing Deadband (50bps) and Trigger Mechanism (100 bps) at the same time, please confirm that any ROE AAM adjustments must fall within 50bps to 100bps. If not confirmed, please state the minimum/maximum range in case of an ROE change.

Response:

Not confirmed. The trigger mechanism evaluated by Concentric is a relative one (tied to average North American litigated allowed returns) and may not be reached, in which case ROE changes would not be limited during the formula period, and may exceed 100 bps.

133.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 9 (2012 Concentric Update)

Formulaic Adjustment Mechanism Design Considerations

On page 9 of the Concentric Update, Concentric discusses "…trigger mechanisms that prompt a review if a predetermined threshold is met, and predetermined periods for rebasing ROE."

133.1 To what extent do such mechanisms, including ceilings and floors and deadbands, as discussed on page 9, satisfy the "Insulated from the Effects of Anomalous and Transitory Market Conditions" criterion on page 8 of the 2012 Concentric Update?

Response:

All three mechanisms would have the effect of insulating or dampening the formulaic result from anomalous and transitory market conditions.

134.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 15 (2010 Concentric Report)

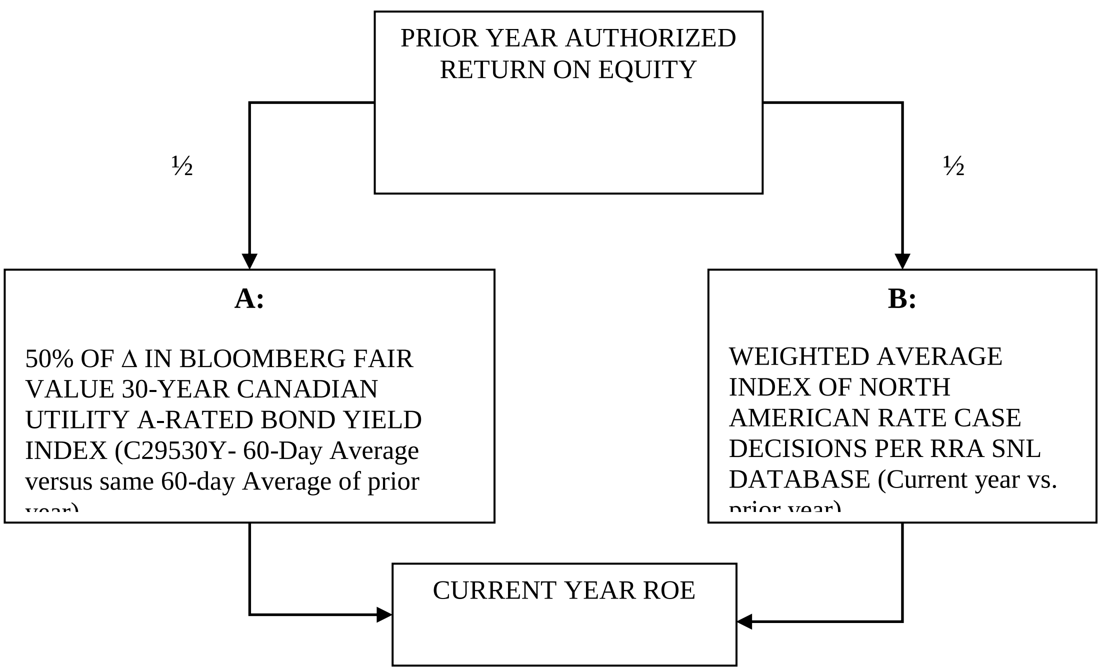
Alternative Formulaic Approaches

On page 15, the 2010 Concentric Report states “Other means of factoring equity returns into AAMs might include incorporating the ROEs authorized by other jurisdictions into the formulaic mechanism. Concentric proposed such a formula in Alberta and Ontario, where an equal weighting of the formulaic adjustment mechanism (specified with a coefficient of 0.50 and use of the Bloomberg 30-year A-rated utility bond yield) was combined with an index of North American allowed utility returns applied to the initial ROE.”

134.1 Specifically, what index did Concentric propose?

Response:

Concentric proposed the following formula:



134.2 Can Concentric confirm that the OEB did not adopt Concentric's proposal to include in the AAM formula an index of North American allowed utility returns?

Response:

Confirmed. The Bloomberg Fair Value Canadian Utility A-Rated Bond Yield was adopted by the OEB to determine the credit spread in its formula, but not the allowed return index.

134.2.1 If confirmed, can Concentric provide the reasons provided by the OEB for not adopting that part of Concentric's proposal in its AAM formula?

Response:

The Board did not cite its reasons for not including the allowed return index in its final decision, thus Concentric is unable to provide the requested reasons for the Board's decision.

135.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, pp. 38-39 (2010 Concentric Report)

Transparency and Data Availability

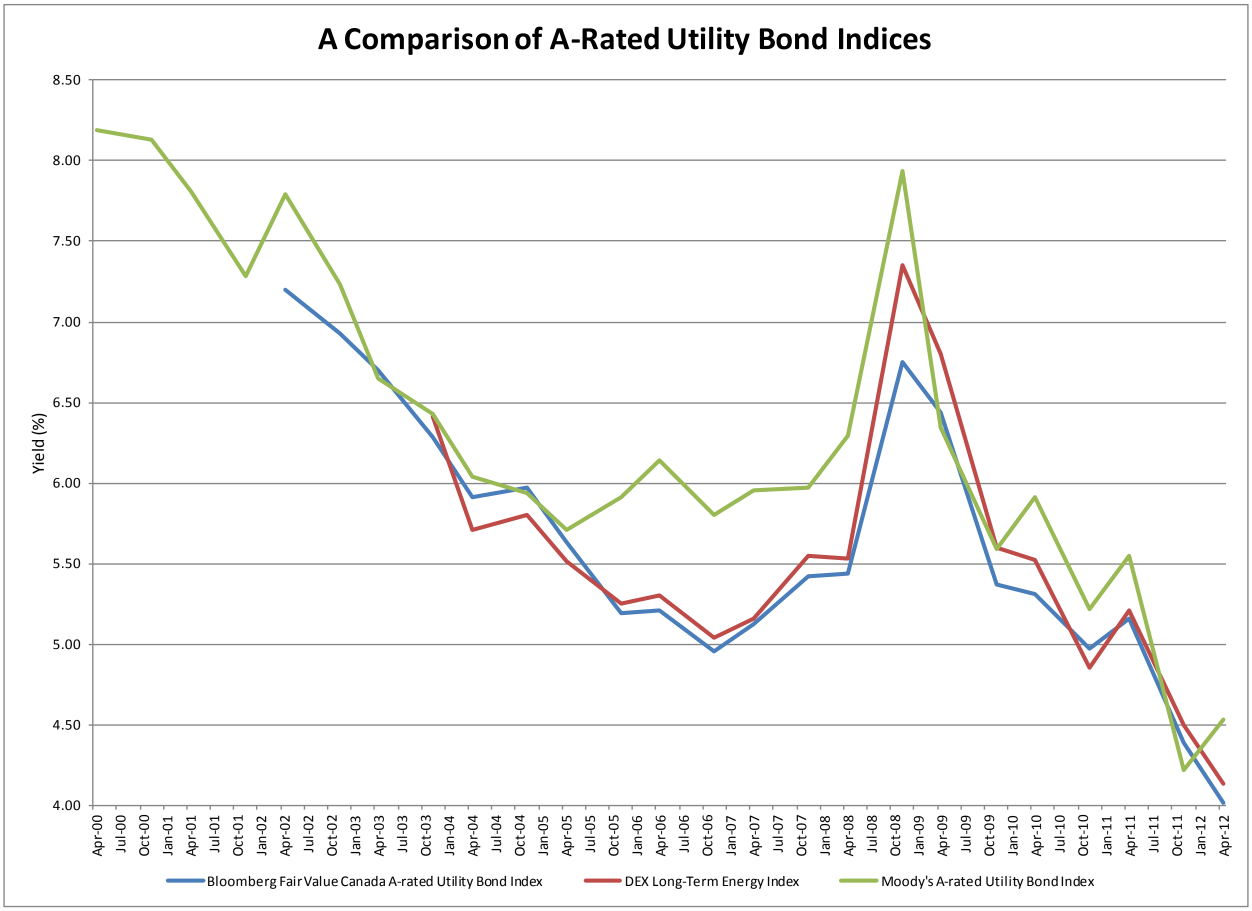
On page 39 of the 2010 Concentric Report, Figure 13 and Figure 14 show a comparison of A-Rated Utility Bond Indices and A-rated Corporate Bond Indices, respectively, for Bloomberg, DEX, and Moody’s.

On page 38, the 2010 Concentric Report states “… the Bloomberg Fair Value Curve and the DEX PC Bond Analytics Universe curve, both representing Canadian bond yield indices for the utility and energy sectors, respectively, are nearly identical, and accordingly, we conclude that these series are reasonable substitutes for Canadian utility bond yields. The Moody’s utility data suggests that the U.S. bond indices and Canadian utility bond indices have diverged in the past, though today all three indices provide similar yields for utility bonds.”

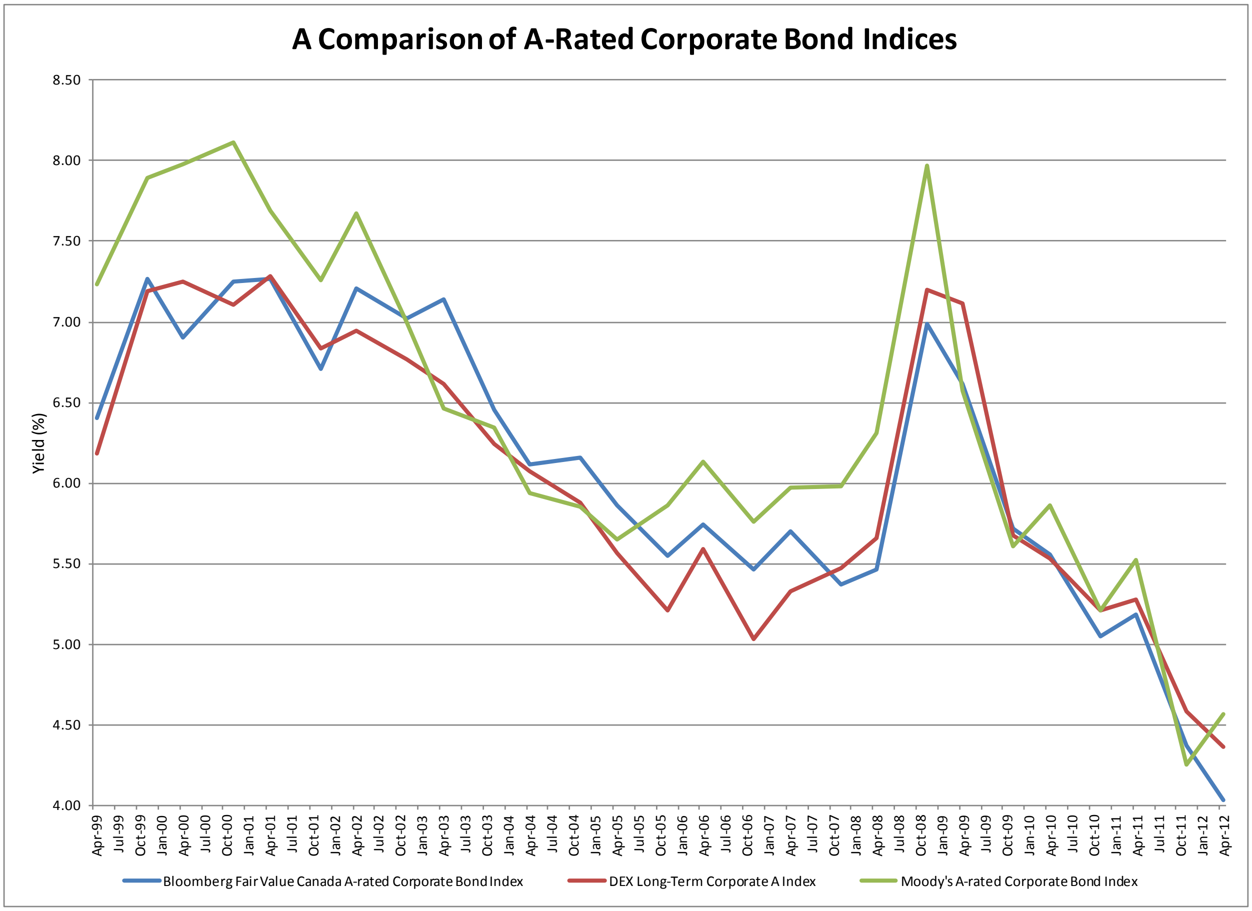
135.1 Please update Figure 13 and Figure 14 to the latest quarter available. Please include the accompanying dataset.

Response:

Updated Figure 13 to the latest quarter is shown below:



Updated Figure 14 to the latest quarter is shown below:

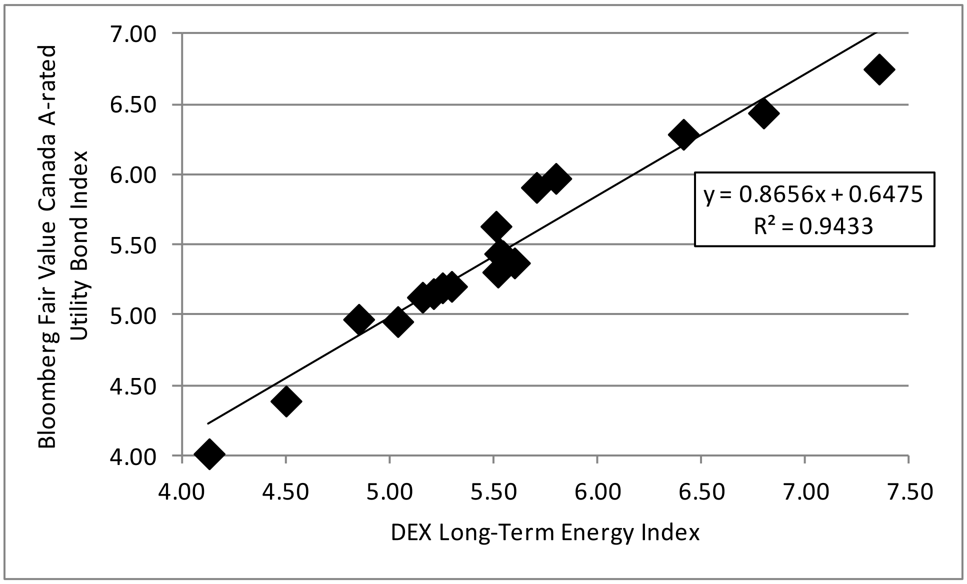


Agreements with vendors prohibit Concentric from disseminating the proprietary Bloomberg and DEX data series. Therefore, the data are being provided confidentially under separate cover to the Commission only for the purposes of this proceeding, and cannot be provided to other parties under the terms of these licenses. Please see Confidential Attachment 135.1.

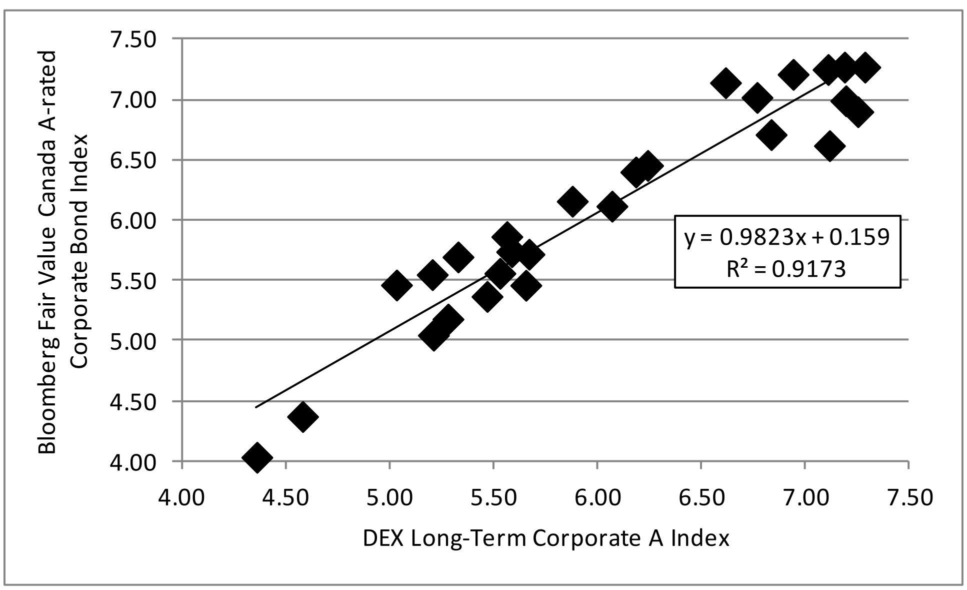
135.2 Please compute the R^2 statistics to demonstrate the correlation between Bloomberg and DEX for the updated Figure 13 and 14.

Response:

Below is a representation and regression equation with the R^2 statistic for the Bloomberg and DEX utility bond data series, presented in Figure 13 of Concentric's 2010 Report. Below, the "y" or dependent variable is the Bloomberg Fair Value Canada A-rated Utility Bond Index; and the "x" or independent variable is the DEX Long-term Energy Index.



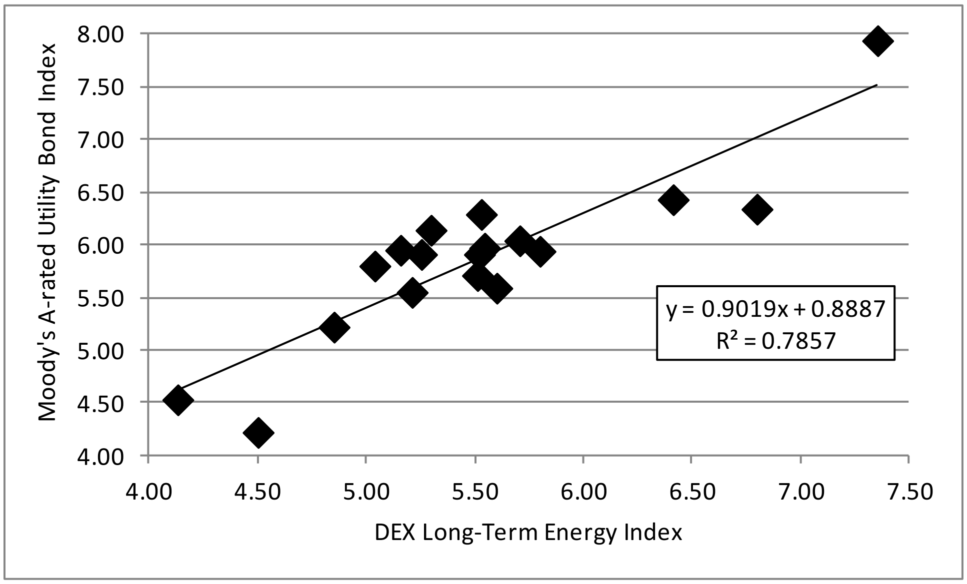
Below is a representation and regression equation with the R^2 statistic for the Bloomberg and DEX corporate bond data series presented in Figure 14 of Concentric’s 2010 Report. Below, the “y” or dependent variable is the Bloomberg Fair Value Canada A-rated Corporate Bond Index; and the “x” or independent variable is the DEX Long-term Corporate A-rated Index.

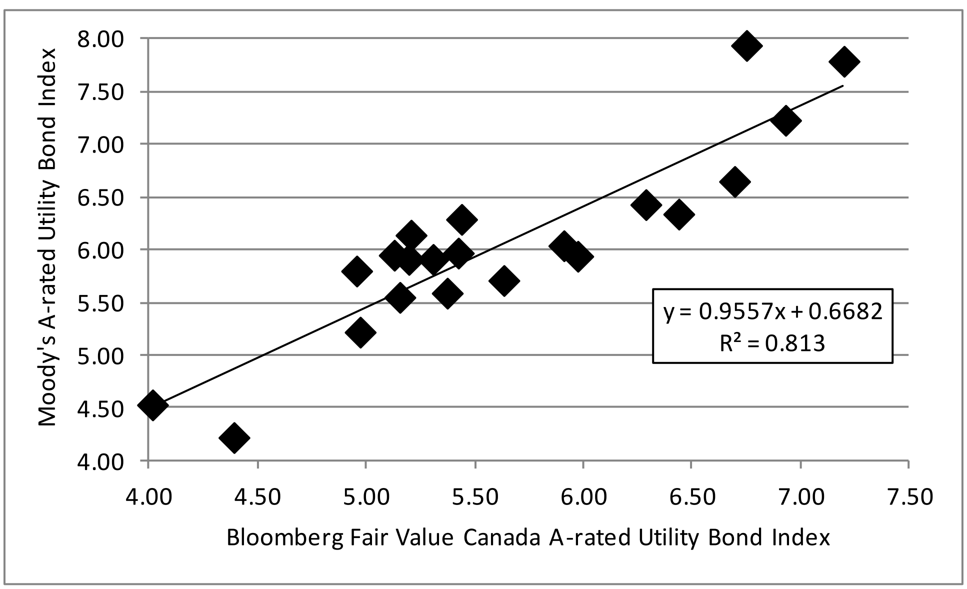


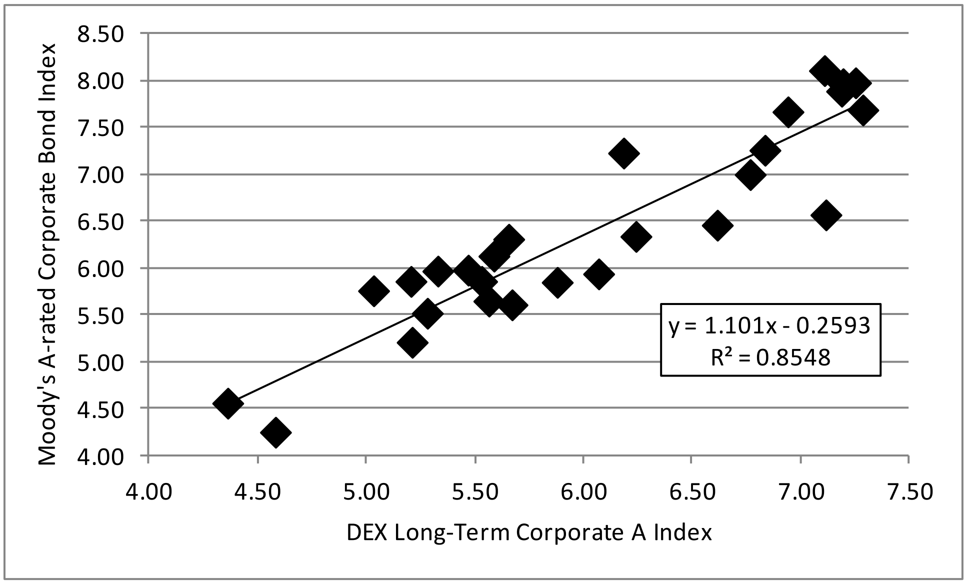
135.3 Please compute the R^2 statistics to show the divergence between Moody's U.S. bond indices and Canadian utility bond indices for the updated Figure 13 and Figure 14.

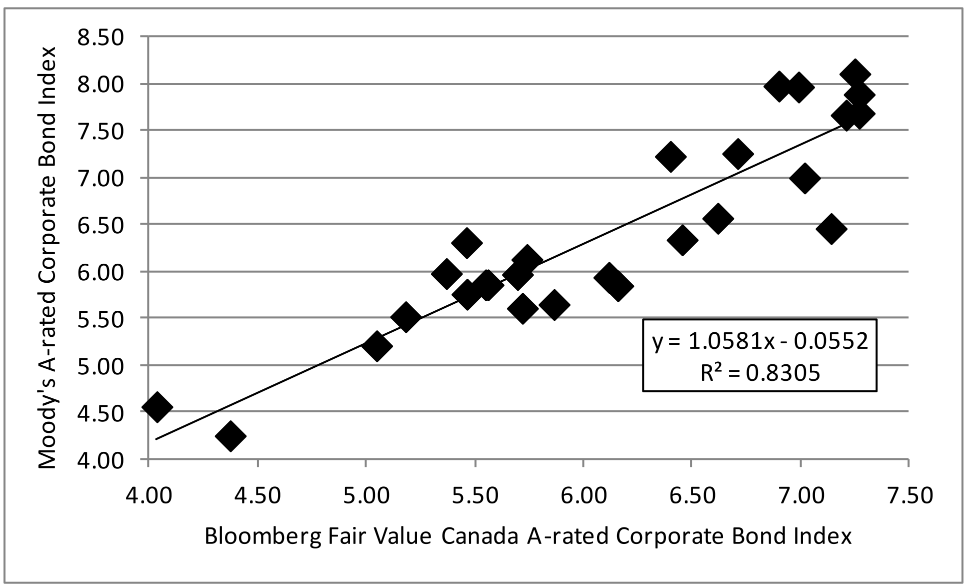
Response:

Results of those regressions are provided below. The Moody's series is the dependent variable "y" variable and the Canadian bond indices are the independent or "x" variable in each instance.









135.3.1 Please provide more detail on the divergence between U.S. and Canadian utility bond yields. During what periods did they diverge? By how much? What were the reasons for the divergence(s)?

Response:

Despite a strong historical relationship, in reviewing the updated Figure 13 provided in response to BCUC IR 1.135.1, Concentric notes two periods of moderate divergence in U.S. and Canadian utility bond yields. In the period between July 2005 and October 2007, U.S. and Canadian bond yields moved opposite one another. The other period of divergence was during the 2008 and 2009 financial crisis when U.S. utility bond yields experienced a greater response to the credit crisis than did the Canadian bond yields, though directionally the two data series were in tandem. Concentric cannot say with certainty what the cause of this divergence was, but assumes it was due to the lead up to the credit crisis where U.S. credit spreads and risk aversion were generally increasing relative to Canada.

135.3.2 To what extend does Concentric consider it likely or possible that U.S. and Canadian utility bond yields will diverge again in the future?

Response:

As noted in the response to BCUC IR 1.135.3, U.S. and Canadian utility bond yields have enjoyed a strong positive statistical relationship. Concentric would expect the same level of high correlation that has occurred in the past to occur again in the future in accordance with the bonds' historical relationship.

136.0 Reference: Evidence of Concentric Energy Advisors Inc.

Exhibit B1-9-6, Appendix I, p. 1 (2010 Concentric Report); Return On Equity and Capital Structure BCUC Decision dated December 16, 2009

Low Government Bond Yields

On page 1 of the 2010 Concentric Report states "… the Commission determined that "a single variable is unlikely to capture the many causes of changes in ROE" and as such, discontinued the AAM."

On page 72 of the 2009 ROE and Capital Structure Decision, the Commission Panel found "The Commission's calculation of the ROE for 2010, as derived from the adjustment mechanism, is 8.43 percent, compared to the Commission Panel's determination that the appropriate ROE for TGI in 2010 is 9.50 percent. The Commission Panel determines that, in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard."

136.1 One of the reasons to discontinue the AAM is due to government bond yields declining to low levels. Would establishing an adder to the low government bond yield increase adjustment to the pre-2009 AAM formula to boost the allowed ROE work as an alternative?

Response:

Concentric believes the use of static adders to bond yields is an ill-advised formulaic alternative. There is well-documented evidence of the inverse relationship between interest rates and the equity risk premium in finance and academic literature and analyses. The application of such an adder would disregard that relationship. As Concentric and others have proven through a variety of analyses, the relationship between equity returns and interest rates has generally been characterized by a 50% sensitivity of equity returns to changes in interest rates. A static adder would ignore this relationship.

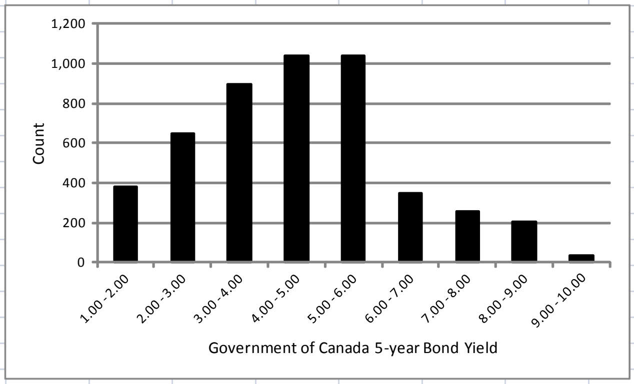
136.1.1 What should be the yield threshold to justify that Canada Government Bond yields are at low levels? Please specify a threshold for 5, 10, and 30-year Canada bond yields.

Response:

The following histograms reflect the upper and lower decile for historical 5, 10, and 30-year Canadian bond yields for the period January 1, 1994 to August 31, 2012.

Government of Canada Bonds
5-Year

Min	Max	Count	Lables
1.00	2.00	380	1.00 - 2.00
2.00	3.00	648	2.00 - 3.00
3.00	4.00	896	3.00 - 4.00
4.00	5.00	1,040	4.00 - 5.00
5.00	6.00	1,037	5.00 - 6.00
6.00	7.00	350	6.00 - 7.00
7.00	8.00	253	7.00 - 8.00
8.00	9.00	205	8.00 - 9.00
9.00	10.00	35	9.00 - 10.00
		4,844	

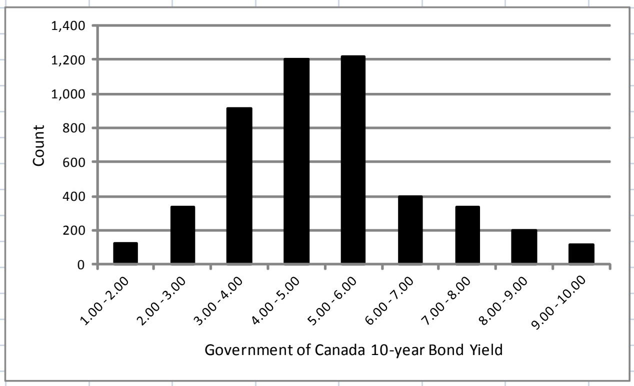


Percentile

10%	90%
2.2099	7.0300

Government of Canada Bonds
10-Year

Min	Max	Count	Lables
1.00	2.00	126	1.00 - 2.00
2.00	3.00	334	2.00 - 3.00
3.00	4.00	916	3.00 - 4.00
4.00	5.00	1,200	4.00 - 5.00
5.00	6.00	1,215	5.00 - 6.00
6.00	7.00	395	6.00 - 7.00
7.00	8.00	339	7.00 - 8.00
8.00	9.00	202	8.00 - 9.00
9.00	10.00	119	9.00 - 10.00
		4,846	

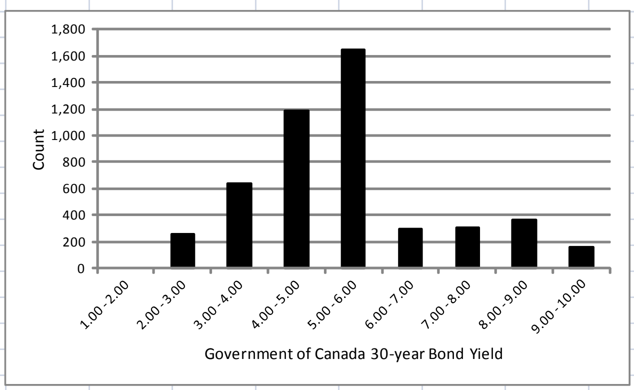


Percentile

10%	90%
3.0620	7.6300

Government of Canada Bonds
30-Year

Min	Max	Count	Lables
1.00	2.00	0	1.00 - 2.00
2.00	3.00	261	2.00 - 3.00
3.00	4.00	634	3.00 - 4.00
4.00	5.00	1,181	4.00 - 5.00
5.00	6.00	1,643	5.00 - 6.00
6.00	7.00	293	6.00 - 7.00
7.00	8.00	306	7.00 - 8.00
8.00	9.00	363	8.00 - 9.00
9.00	10.00	162	9.00 - 10.00
		4,843	



Percentile

10%	90%
3.6360	8.0800

136.1.2 Hypothetically speaking, in a low Canada Government Bond yield environment, if the low government bond yield increase adjustment is to top up the allowed ROE to 9.5 percent (which was found to meet the Fair Return Standard in 2009), please estimate the range between what the pre-2009 AAM formula would have calculated now for the allowed ROE and the allowed ROE of 9.5 percent.

Response:

If Concentric correctly understands the Commission's question, Concentric is being asked to calculate the difference between the pre-2009 formulaic result updated through August 2012 and the 9.5% rebased ROE. As shown below, Concentric's update of the formulaic result in BC would yield an ROE of 7.20%, therefore the difference from the 9.50% rebased ROE is 230 basis points.

Calculation Of Allowed 2012 Rate Of Return On Common Equity
For A Low-Risk Benchmark Utility
(Per Commission Order G-35-94,
Amended by Order G-80-99, Order G-109-01 and Order G-14-06)

A forecast of long-term Canada bonds is developed based on the Consensus Economics forecast of 10-year bonds (step 1) and the observed spread between 10- and 30-year bonds over a defined period (step 2). This establishes a forecast yield for long Canada bonds (step 3).

1.	Ten Year Canada Bond Yield – end of November 2012 (Consensus Economics, August 2012 Consensus Forecast)	1.80%
	Ten Year Canada Bond Yield – end of August 2013 (Consensus Economics, August 2012 Consensus Forecast)	2.30%
	Average of 3 and 12 Month Forecasts	2.05%
2.	Add average yield spread between 10-year and 30-year bonds as reported by the Bank of Canada for all trading days in July 2012.	0.61%
3.	Equals forecast yield on long-term Canada bonds	2.66%

As per Commission Order G-14-06, the approved benchmark return on equity (ROE) is 9.145 percent assuming a 30-year long Canada bond yield of 5.25 percent. Where the forecast yield is greater or less than 5.25 percent, a sliding scale adjustment raises or lowers the benchmark ROE by 75 percent of the change in the forecast yield on long-term Canada Bonds (step 4). The unrounded allowed ROE in percentage terms is rounded to the nearest 2 decimal places (step 5).

4.	Unrounded allowed ROE based on sliding scale adjustment: 9.145 – (0.75 * (5.25 – 2.66))	7.202%
5.	Allowed ROE	7.20%

136.1.2.1 Is the calculated range an acceptable adjustment to the AAM formula to adjust for low Canada Government Bond yields?

Response:

Concentric would not endorse a methodology that included a static adder for low government bond yields. Conceivably this methodology would result in a 230 basis point drop as bond yields move out of the “low” government bond yield environment. Please also refer to the response to BCUC IR 1.136.1.

D. A GENERIC METHODOLOGY OR PROCESS FOR EACH UTILITY TO DETERMINE ITS UNIQUE COST OF CAPITAL IN REFERENCE TO THE BENCHMARK LOW-RISK UTILITY

137.0 Reference: FortisBC Utilities Evidence

Exhibit B1-9, p. 32

Business Risk

On p. 11 of the FBCU's evidence, the FBCU state that "Ms. McShane has noted in her evidence that the determination of a public utility's risk profile is not a simple matter of tallying-up, grouping or ranking risk factors; all of the factors must be considered holistically. There is no formulaic way to assign a value or weighting to specific risk factors or utility/utility sector characteristics that would apply across multiple utilities and generate the appropriate cost of capital for each one."

137.1 To what extent are the FBCU aware of benchmarking exercises in other jurisdictions that use performance characteristics to benchmark the performance of a utility against its peers? Please describe any examples of which the FBCU are aware and why they may or may not be applicable in BC.

Response:

The numbering of this question in the original exhibit was marked as 3.3. The FBCU have corrected the numbering to 137.1.

Benchmarking is a commonly employed tool in the utility industry, most typically used to evaluate operational efficiency at the company, functional area, or plant level. For example, Enbridge recently submitted a benchmarking study on its gas distribution operations to the OEB as part of its 2013 rate application where the Company is rebasing its rates following a 5 year incentive rate plan. The study benchmarked factors such as size (volumes, customers, miles), customer profiles (residential, commercial, industrial), costs (materials, labor, capital), and various relationships between these metrics (*Benchmarking Study,* prepared for Enbridge Gas Distribution, Concentric Energy Advisors, January 27, 2012). Such studies may be applicable in BC, depending on the purpose, but are not traditionally submitted as part of cost of capital determinations. Benchmarking peers are typically chosen at the operating company, functional or plant level, whereas cost of capital peers are selected at the holding company level where the securities are traded. Screening criteria are typically employed in cost of capital studies in order to select a comparable study group. This practice is employed by both Ms. McShane and Dr. Vander Weide.

138.0 Reference: FortisBC Utilities Evidence

Exhibit B1-9, p. 34

Business Risk

On page 34 of the FBCU's evidence, the FBCU state that "The FBCU submit that it may be efficient, given the small size of thermal energy systems, to have a single process to address cost of capital issues for thermal energy systems, irrespective of the provider. This would include FEI and FAES' Thermal Energy Services, and similar systems to be operated by developers or providers like Corix Multi Utility Services.

138.1 How would such a process consider, if at all, potential differences in business risk between FEI affiliates and other providers such as Corix?

Response:

The FEU believe that irrespective of who the service provider is (FEI affiliates or other providers), these much smaller utilities and TES projects are relatively similar in scope and risk characteristics compared to the benchmark utility, which makes comparability of returns among the small TES projects justified.

139.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, Section X, pp. 134-136

Generic Company-Specific Matters: Size

On page 134, Ms. McShane submits that "In the assessment of investment risk, size has two dimensions which should be considered in the determination of specific utilities' ROEs and common equity ratios: (1) A small utility does not have the opportunity to diversify its risks to the same extent as a larger utility. … (2) Smaller utilities have fewer financing options…"

139.1 Please indicate which criteria and measurement unit are used to define 'a small utility'. What range of values do these criteria have to be within to be defined a 'small utility'?

Response:

"Small" in this context would incorporate a number of criteria, including number of customers, throughput or sales, and assets. Ms. McShane does not consider that there is a "bright line" that defines small. There are gradations of size. She would view a utility with assets under $100 million as very small, but even utilities with assets in the $500-$750 million range are still relatively small compared to the typical firm included in the S&P/TSX Index. To put this in perspective, the median size based on total assets of the smallest decile of the S&P/TSX Index is $400 million, the median of the 5th decile is $3.3 billion and the median of the largest decile is $75 billion.

139.2 Please clarify whether 'smaller utilities' in (2) are meant to be smaller than 'a small utility' in (1). If so, how much smaller are they?

Response:

No. The term in both cases should have been "small".

Ms. McShane also states that "Regulators have recognized small size as a factor in establishing capital structures and ROEs for utilities" and gives the example of the AUC.

In contrast, the OEB states "The Board concludes that utility size no longer represents an accurate proxy for risk. As a result, there is no basis upon which ratepayers should be required to bear different costs, associated with different capital structures, on the basis of distributor size. The question the Board must ask is whether ratepayers of smaller distributors should pay higher rates than those of larger distributors because of a thicker equity component. For these reasons it is the Board's view, that for ratemaking purposes, a single capital structure for all distributors is appropriate." (OEB's *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, December 20, 2006, p. 7)

139.3 Please comment on the OEB's decision to stop considering utility size as a proxy for risk in setting capital structures.

Response:

In Ms. McShane's view, the OEB was, at least in part, motivated to reduce barriers to further consolidation of the industry. In discussing the issue of size differentiated capital structures in its 2006 cost of capital report, the OEB stated that, "This trend [prior mergers and acquisitions in the Ontario distribution sector] underscores the need to ensure that the Board does not create barriers to consolidation. In the Board's view, one of those barriers is the differing capital structure of distributors." (OEB, *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, December 2006, page 6). In arriving at its decision to eliminate any size-differentiated capital structures, the OEB disregarded the recommendations of its Staff's experts. The Staff's experts had recommended splitting the Ontario distributors into two size groups, ones with less than $300 million in rate base excluding working capital (50%/50% debt/equity) and ones that had more than $300 million in rate base excluding working capital (60%/40% debt equity).

On page 135, Ms. McShane refers to the Ibbotson Associates Inc. study on small size and returns, which finds that "In the context of the CAPM, an incremental beta of 0.32, when applied to a market risk premium of 7.25%, indicates an incremental equity risk premium of over 200 basis points (7.25% x 0.32) for a Micro-Cap company relative to a Mid-Cap stock."

139.4 Do the FBCU know of any other studies on size and returns that would be based on the other tests, such as the DCF model or the comparable earnings model?

Response:

No. Neither the FBCU nor Ms. McShane are aware of any size studies that are based on cost of equity models other than CAPM.

139.4.1 If so, please summarize their findings and provide supporting references.

Response:

As indicated in response to BCUC IR 1.139.4, neither the FBCU nor Ms. McShane is aware of any size studies that are based on cost of equity models other than CAPM.

On page 136, Ms. McShane concludes that small size should be taken into account when evaluating ROEs and capital structures of individual BC utilities.

139.5 Please indicate how and to what extent 'small size' should be taken into account when evaluating ROEs and capital structures of standalone thermal energy service projects of FAES. Please justify the response.

Response:

The small size of the FAES projects warrants a higher common equity ratio than the recommended common equity ratio for the benchmark FEI to recognize that small utilities have more limited access to debt capital than large utilities. Business risk factors that are related to small size, particularly the small customer base from which the fixed investment has to be recovered over time, the lack of diversity in the operations, asset concentration and exposure to event risk warrant an equity risk premium relative to the benchmark utility ROE. As there are no publicly-trade proxies for these very small utilities, the estimation of the incremental equity ratio and ROE relative to the benchmark requires judgment. However, the available studies on small size indicate that the incremental overall return (combination of equity ratio and ROE) relative to the benchmark FEI should be material.

E. A METHODOLOGY TO ESTABLISH A DEEMED CAPITAL STRUCTURE AND DEEMED COST OF CAPITAL, PARTICULARLY FOR THOSE UTILITIES WITHOUT THIRD-PARTY DEBT

140.0 Reference: Debt Related Matters

Exhibit B1-9, Evidence, Section 2.7, p. 29

Appropriate Circumstances for Deemed Debt

On page 29, the FBCU state "Deemed debt makes the most sense for small utilities, such as a separate division or class of service within a larger regulated utility, or for a regulated utility subsidiary within a larger corporate organization, where it would not be as efficient or economic to raise its own debt on a third-party basis. The small size of the utility, be it a division or stand-alone entity, could make debt issuance inefficient due to the high costs of issue relative to the size of the issue that may make the effective debt cost higher than it would otherwise be, or where the size of the utility precludes it from accessing appropriate debt terms. In these instances, a deemed debt would be more efficient.

140.1 In the case of the FBCU, please provide an exhaustive list of all the cases that would fall in each of the stated categories: (1) separate division within a larger regulated utility; (2) separate class of service within a larger regulated utility; and (3) regulated subsidiary within a larger corporate organization.

Response:

The following is a list of the cases that would fall into the stated categories:

(1) Separate division within a larger regulated utility:

Fort Nelson is a distinct division of FEI.

(2) Separate class of service within a larger regulated utility:

TES projects, such as Delta School District and Tsawwassen Springs, depending on outcome of AES Inquiry, may be projects within a separate class of service of FEI, although they currently reside in FAES.

(3) Regulated subsidiary within a larger corporate organization:

FEW is a regulated subsidiary for which it would not be efficient or economic to raise its own debt on a third party basis.

140.1.1 Would there be other categories/types of small utilities for which deemed debt would make the most sense?

Response:

FBCU believes that categories noted in the preamble to this question represent appropriate situations where deemed debt may be appropriate, but there could also be other situations that deemed debt may make sense.

140.2 How would the FBCU define the term ‘small’ as used in the preamble to the question in such phrases as ‘deemed debt makes the most sense for small utilities’ and ‘the small size of the utility could make debt issuance inefficient’?

Response:

The FBCU does not have a specific value in mind for defining the use of deemed debt. FBCU would consider the use of deemed debt to be warranted when it is apparent a debt issuance is inefficient due to the high costs of issuing debt relative to the size of the issue that may make the effective debt costs higher than it would otherwise be because of the utility’s size, or where the size of the utility precludes it from accessing appropriate debt terms. Please refer to the response to BCUC IR 1.140.2.1

140.2.1 Which criteria, financial, operational or otherwise, would the FBCU use to define ‘small’ and why?

Response:

The assessment as to whether deemed debt is appropriate should involve some judgment to ensure that the use of deemed debt is limited to circumstances where it is efficient to do so. The factors in assessing whether the Utility would be able to raise the requisite debt in a cost efficient manner at the desired terms will include financial metrics such as asset base or enterprise value, which are typically used to assess size. Please see also the response to BCUC IR 1.40.2.

140.2.2 Can the definition of 'small' be objective or is it subject to some degree of judgment? Why or why not?

Response:

Please refer to the responses to BCUC IRs 1.140.2 and 1.140.2.1.

141.0 Reference: Debt Related Matters [E]

Exhibit B1-9, Evidence, Section 2.7, pp. 29-30; Exhibit B1-9-6, p.123

Basis for Calculating Deemed Interest Rate

On pages 29-30, the FBCU states “The FBCU have identified two reasonable options for determining the deemed interest rate applicable in the scenarios noted above. The first option is to assign a credit rating on a stand-alone basis, and then obtain indicative quotes from investment dealers or banks based on the credit rating of a comparable proxy issuer. This approach is consistent with the stand-alone principle, and is how FEW has financed its debt component of capital structure. An alternative option would be to use the embedded cost of debt of the issuing entity as the deemed interest rate and allocate the deemed debt and deemed interest rate based on an approved capital structure. Currently, Fort Nelson debt is deemed and the rate is the embedded cost of debt of FEI.”

141.1 Please provide all the pros and cons for each of the two options for determining the deemed interest rate.

Response:

Option 1 – Assign a credit rating

Pros

- Chartered banks can provide indicative market quotes
- The approach is consistent with the stand-alone principle, which supports a cost rate that reflects the use of the capital, rather than the source.

Cons

- Determining the credit rating is a subjective exercise. Specifically, assigning a credit rating requires identifying comparable companies that are rated to be able to assess the appropriate credit rating. As small regulated companies are not rated, largely due to the very fact that they are small and thus do not access the public markets, there are no directly comparable proxies for these utilities. Please refer to the response to BCUC IR 1.147.1.

Option 2 – Use embedded cost of debt

Pros

- As the actual debt issuing entity is regulated, its embedded cost of debt can be objectively determined.

- There are regulatory precedents for this approach.

Cons

- If the issuing entity is otherwise not a utility regulated by the BCUC, its embedded cost of debt would not be subject to regulatory oversight.
- The embedded cost of debt may not reflect a current market rate of interest. This “con” is most applicable to new projects.
- Using the issuing entity’s embedded cost of debt may be a departure from the stand-alone principle.

141.2 Under the first option, please provide the generic formula that the FBCU would use to calculate the deemed interest rate.

Response:

The following table outlines a hypothetical example of the calculation:

Credit Spread	Chartered Bank 1 Quote	2.50%		
	Chartered Bank 2 Quote	2.00%		
	Average		**2.25%**	A
Government of Canada Benchmark Yield				
	Chartered Bank 1 Quote	1.90%		
	Chartered Bank 2 Quote	2.00%		
	Average		**1.95%**	B
Issuance Fee (Hypothetical Annualized)			**0.05%**	C
Total Deemed Rate			**4.25%**	A+B+C

141.3 Under the first option, is the assignment of a credit rating on a stand-alone basis an objective or subjective exercise? Please justify the response.

Response:

Please refer to the responses to BCUC IRs 1.141.1 and 1.147.1.

141.3.1 If such assignment carries a degree of subjectivity, how can it be minimized?

Response:

Please refer to the response to BCUC IR 1.147.1.

141.4 Under the first option, is it sufficient to obtain the indicative spread based on the credit rating of only one comparable proxy issuer? Why or why not? What would be an ideal number of comparable proxy issuers?

Response:

If available, ideally more comparable proxy issuers will provide a better representative sample than just one. The greater number of issuers will help reduce any noise caused by specific company risk that is not directly comparable to the entity. However, in a situation where only one issuer exists, then this would be sufficient.

141.5 How do the FBCU define "comparable proxy issuer?" Which criteria would the FBCU use to conclude that another issuer is a comparable proxy and why?

Response:

A comparable proxy issuer would be one with a credit rating or ratings that are most similar to the assigned credit rating of the entity, and would be one that is preferably operating in a relatively similar line of business.

141.5.1 Is the exercise of finding comparable proxy issuer an objective or subjective one? Why?

Response:

It is objective inasmuch as the comparable proxy issuers' credit ratings are known with certainty. The more subjective component is determining the group of issuers that are viewed as comparable, and the industries they are drawn from.

141.5.2 If such an exercise carries a degree of subjectivity, how can it be minimized?

Response:

Please refer to the response to BCUC IR 1.141.5.1. The subjectivity can be reduced by first attempting to identify proxy companies that are engaged in similar industries or lines of business.

141.6 Under the second option above, please explain the financial impact of using an embedded cost of debt as opposed to applying an incremental cost of debt in the views of the FBCU.

Response:

There is no financial impact. In both cases, whether an embedded rate or incremental cost of debt is used, the cost would be recovered by the entity through its cost of service.

141.6.1 Under the current low-interest monetary policy environment, would using an embedded cost of debt overstate the actual cost of debt borrowing for that utility? Please explain why or why not.

Response:

It depends on the embedded cost of debt of the issuing entity. In general, however, given the current level of interest rates, and the fact that an embedded rate incorporates the cost of past debt issuances, a current deemed cost of debt is likely to be higher than the actual (market) cost of debt for that utility.

141.6.2 Would using an embedded cost of debt be in contrast to the first option, which seeks indicative quotes from investment dealers based on the current credit ratings of comparable proxies?

Response:

Yes. They are different options, each with its own pros and cons. Please refer to the response to BCUC IR 1.141.1

In Exhibit B1-9-6, Appendix F, page 123, Ms. McShane states that "the utility itself can provide yields and spreads on new or outstanding debt issues of similarly rated entities to support its requested cost of debt."

141.7 The above statement appears to suggest that for small utilities which do not issue third-party debt, one option is to look at the multitude of outstanding corporate bonds (footnote 146) and the debt issues of similar risk entities. How does this statement compare to FBCU's suggestion and its current practice as it pertains to Fort Nelson, of using an embedded cost of the issuing entity?

Response:

Ms. McShane's referenced statement is consistent with the FBCU's Option 1, as per the responses to BCUC IRs 1.141.1 and 141.2. With respect to the FBCU's use of an embedded cost of debt for Fort Nelson, it is a division of FEI, albeit with its own rate structure, capital structure and ROE. The use of FEI's embedded cost of debt for Fort Nelson reflects historic practice, recognizing the combination of: Fort Nelson is not a separate legal entity; it is too small to access debt on its own; it is too small to measurably impact FEI's cost of debt; and the practice is consistent with the approach taken for the remainder of FEI's natural gas distribution business, that is, new customers are charged the same (embedded) cost of debt irrespective of the timing of their attachment to the gas distribution system.

141.8 In the opinion of Ms. McShane, what are the implications of using an embedded deemed cost versus an incremental deemed cost?

Response:

It depends on the circumstances. The issue, in Ms. McShane's view, is most relevant in scenarios where the project is a different line of business or class of service than the core business of a regulated utility or of a company which includes a regulated utility, but is otherwise unregulated. If the issue is the cost of debt for an alternative energy project, using an incremental cost of debt relevant to the project will mimic the circumstances where the project is a new, stand-alone utility that has to raise new financing and has no embedded cost of debt *per se*. On the other hand, such projects are being financed from a pool of debt raised by a single issuer, as it is inefficient and too costly for each project to raise funds on its own. The use of the embedded cost implicitly recognizes that, typically, when new funds are raised by an issuer, those funds are not colour-coded for, and traced to, a particular project or service. While embedded cost rates are likely to deviate from market rates of interest at any given time, due to issuance timing, where the issuer's cost of debt is unlikely to be measurably affected by the financing of projects, using an embedded cost of debt is an administratively efficient way to allocate debt issued by a single regulated entity, allows the benefits that issuing all debt centrally to be shared, and provides a reasonable degree of assurance that the regulated entity that raises the debt will be able to recover its actual incurred costs of debt.

In Directive 1d) in Commission Order G-71-12, with respect to FAES's Revisions to Rates and Rate Design for Thermal Energy Services to Delta School District Number 37, the Commission directed as follows:

"d. The cost of debt rate of 5.91 percent filed by FAES is denied as it does not meet the condition and intent set out in Directive 3(c) of Order G-31-12. FAES is directed to re-calculate its deemed cost of debt rate based on BBB-rated entities operating specifically in the Thermal Energy Services (TES) class of service and file it with the Commission within 10 business days from the date of this Order. However, if FAES is not able to find such entities, the Panel would accept if FAES used BBB-rated distribution utilities, such as AltaGas Ltd. and Emera Inc., as proxy for the TES class of service. Further, going forward:

i. If the Commission approves, in the Generic Cost of Capital (GCOC) proceeding, a methodology to establish a deemed interest rate automatic adjustment mechanism (Interest AAM), FAES is directed to update its cost of debt rate annually using that Interest AAM.

ii. Alternatively, if the Commission does not approve an Interest AAM in the GCOC proceeding, FAES is directed to review its deemed cost of debt rate in its revenue requirements annual filing, using the same methodology as directed in this Order and accompanying Reasons for Decision."

141.9 Given the scarcity of BBB-rated utilities in Canada that can be used as proxy for the TES class of service, and the possibility that utilities with BBB rating be upgraded/ downgraded at some point, please comment on the pros and cons of the following methodology to calculate the deemed long-term debt rate for TES projects:

- Step 1: Obtaining the yield on an appropriate Government of Canada bond as the benchmark;
- Step 2: Obtaining the bond yield spread between the Government of Canada bond benchmark and a high grade utility (A or A low utility) and adding it to the rate in Step 1;
- Step 3: Obtaining the spread between BBB-rated bond spreads and A-rated bond spreads. This step could be looking at historical data (e.g., two most recent years) to have more data points. Then, adding this spread between BBB and A-rated bond spreads to the rate calculated in Step 2.

Response:

Pros

- There is greater liquidity and more data points in the pool of BBB- rated entities generally than there would be using BBB-rated utilities only to derive the BBB/A spread.
- The general approach is transparent and verifiable, i.e., indices for all three debt rating categories are available by subscription, so that the resulting spreads can be verified by the Commission.

Cons

- There are fewer BBB rated entities that raise debt with terms over 10-years.
- While similarly rated entities, a general group of BBB-rated entities may have materially different spreads than BBB rated utilities at different points in the business cycle.
- Use of a universe of bonds limits the ability to easily identity a spread to match a specified term for the debt.

The steps appear to be a reasonable approach to determining a cost of deemed debt.

141.10 Under the first option, and until such time when the small utility obtains third-party debt, in which case the actual cost of debt would be used, please discuss whether the deemed debt rate calculated initially should be fixed for a period of time (e.g., 5 years, the duration of the contract or other) or whether it should vary on an annual basis, due to the variations of the benchmark yield and the credit spreads above the benchmark. What are the pros and cons of each method?

Response:

The term of debt can be matched to the term of a contract or a term that represents the longer-term nature of the assets, i.e., long-term assets are financed with long-term debt. In the FBCU's view, the deemed debt rate should be fixed to match the selected term. The FBCU do not see any pros with annual varying the imputed cost of debt for what in principle should be viewed as a fixed-rate debt instrument. Varying a long-term debt rate annually potentially exposes the issuer or the customer to avoidable interest rate risk.

141.10.1 Under the first option, and until such time when the small utility obtains third-party debt, and in a situation where the small utility has an approved levelized or fixed rate design for the duration of its service contract, should the deemed debt rate and deemed debt component of the capital structure also be fixed for the same period. Please explain why or why not.

Response:

Please refer to the response to BCUC IR 1.141.10.

141.10.2 In a situation where the small utility has an approved cost of service mechanism and an annual or biennial revenue requirement filing is required, should the deemed cost of debt be evaluated on same timing as the revenue requirement test period? Please explain the pros and cons of this approach.

Response:

For long-term debt, not unless the small utility has actually issued debt whose cost differs from the previously deemed rate or there is additional debt that is required to be deemed in order to maintain the approved capital structure. Please refer to the response to BCUC IR 1.141.10. If the Commission requires that there be a small component of short-term debt in the capital structure, then that cost rate should be reviewed at the time of the revenue requirements review, as is the case with other regulated utilities who forecast that they will use some short-term debt in their regulated capital structure during a test period.

On page 30, the FBCU state that "the concept of a benchmark credit spread is not required. The more appropriate approach is to have debt approved by the Commission on a case specific basis."

141.11 Please explain what is meant by "a case specific basis" in the above statement. Does this imply "project-specific" basis?

Response:

Case specific means that that the approach to be used should depend on the type of utility involved and that each utility (or project) would have its debt approved by the Commission.

With respect to TES projects, the FBCU are of the view that an individual TES project will likely not have a significant business risk difference from other TES projects. The FBCU believe that it is reasonable, in order to achieve regulatory efficiency and streamline the regulatory process for these projects, to consider utilizing consistent capital structures, equity risk premiums and designated stand-alone credit ratings for each project that falls within the TES class of service, when determining the specific debt for such projects.

OEB – Appendix C of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009 (Exhibit A2-21) and OEB – Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012 (Exhibit A2-22) explain the OEB's methodology to calculate the deemed long-term debt rate for Ontario's distribution utilities.

141.12 Please discuss the applicability of the OEB's methodology regarding the calculation of the deemed long-term debt rate (e.g., 30-year bond as the benchmark, A-rated utility, long Canada bond forecast) to BC utilities without third-party debt, such as FAES's TES projects (DSD, Tsawwassen Springs Development, PCI Marine Gateway) and other district energy systems (Corix UniverCity and River District Energy).

Response:

The FBCU are of the view that the OEB formula is inappropriate for the following reasons. First, the OEB formula is based on the assumption of an A rating. The credit rating that is presumed in the OEB formula is not appropriate for small BC utilities, including the TES class of service. The FBCU agree with Ms. McShane, as indicated in response to BCUC IR 1.144.5.1, that a more reasonable credit rating for the small utilities, particularly the TES class of service, would be in the range of BBB to BBB(low). Second, the OEB formula is based on a 30-year bond yield, which might not be relevant in all cases, e.g., if there were a 20-year contract, then the appropriate deemed term should be 20 years. Third, as the OEB formula operates, the deemed cost of debt would be reset based on the formula when rates are reset. As discussed in response to BCUC IR 1.141.10, the FBCU believe that the deemed cost rate should remain unchanged for the deemed term of the debt.

141.12.1 Specifically, what are the advantages and disadvantages of using this formula in the case of BC utilities without third-party debt?

Response:

Please refer to the response to BCUC IR 1.141.12.

In the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, the OEB states on pages 53-54: "The deemed long-term debt rate will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances. These circumstances include:

- For affiliate debt (i.e., debt held by an affiliated party as defined by the Ontario *Business Corporations Act, 1990*) with a fixed rate, the deemed long-term debt rate <u>at the time of issuance</u> will be used as a ceiling on the rate allowed for that debt. [Emphasis added]
- For debt that has a variable rate, the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. This applies whether the debt holder is an affiliate or a third-party.
- The deemed long-term debt rate will be used where an electricity distribution utility has no actual debt.
- For debt that is callable on demand (within the test year period), the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. Debt that is callable, but not within the period to the end of the test year, will have its debt cost considered as if it is not callable; that is the debt cost will be treated in accordance with other guidelines pertaining to actual, affiliated or variable-rate debt."

141.13 Please comment on the applicability in BC of using a deemed long-term debt rate as a proxy or ceiling for what would be considered to be a market-based rate in each of the circumstance listed by the OEB.

Response:

As the FBCU do not know what the deemed debt rate would represent, it is impossible to fully respond to this question. As a general proposition, the FBCU believe that setting a ceiling on the allowed debt cost by reference to yields and spreads on a published index may be unduly restrictive. In the FBCU's view, as suggested by Ms. McShane at page 123 of her testimony, the Commission can use the yields from published debt indices (e.g., the DEX long-term BBB corporate debt index) to test the reasonableness of a proposed debt cost, but should not impose a ceiling. The FBCU would also observe that the Commission would need to approve arrangements as to term, coupon and amount under Section 50 of the Utilities Commission Act.

142.0 Reference: Debt Related Matters

Exhibit B1-9, Evidence, Section 2.7, p. 30

Reference Point for Long-Term Interest Rates

The FBCU state that "It should be based on: an underlying Government of Canada bond yield reflecting the proposed term of debt, and that could be either the 10-year or 30-year bond as the benchmark, or an interpolation of the two benchmarks, and […]"

142.1 If an interpolation of the 10-year and 30-year benchmarks is used, should it be linear? Why or why not? If not linear, what should it be and why?

Response:

The precise relationship depends on the shape of the yield curve. To test whether a linear relationship would be a reasonable approximation of the interpolated value of the 20-year yield, the Bank of Canada's zero coupon yield curves were used. Over the entire period for which the 30-year zero coupon yield has been available (1991 to 2012), the average difference between the 20-year zero coupon yield and the average of the 10-year and 30-year zero coupon yields was less than 4 basis points. Given the small difference between the two, interpolation based on a linear relationship is a reasonable approximation of the yield on a 20-year debt issue.

143.0 Reference: Debt Related Matters

Exhibit B1-9, Evidence, Section 2.7, p. 31

Portions of Short-Term and Long-Term Debt

On page 31, the FBCU state "The appropriate portion of short-term and long-term debt will depend on the underlying nature of the assets and timing. The FBCU will generally use short-term debt when assets are in development and refinance that debt following project completion when the balance is large enough to support a long-term bond issue. Typically, a utility's fixed assets in service will make-up the majority of its overall asset base and thus its debt should be mostly long-term in nature to avoid exposure to refinancing risk. Short-term debt is also important, however, as it funds working capital, which can fluctuate significantly due to seasonal variations. The FBCU submit that there is no 'appropriate portion' of short-term debt, and that on average, short-term debt will make up a very small component of a utility's overall capital structure.

143.1 Please clarify whether the statement "there is no 'appropriate portion' of short-term debt" is applicable to BC utilities without third-party debt that may require a deemed debt and deemed interest rate on that debt?

Response:

To clarify, the statement was not intended to mean that short term debt is not appropriate for the utilities referred to above, but to convey the point that there is not a prescriptive or set amount that is appropriate, as it will vary based on the situation of the utility in question. Therefore, yes, the statement is still applicable.

143.1.1 If so, do the FBCU mean that the appropriate portion should be zero or that it should be determined on a case by case basis? Why?

Response:

No 'appropriate portion' means the short-term and long-term (fixed rate debt) fluctuates and would be determined on a case by case basis. Please refer to the response to BCUC IR 1.143.1.1.

143.1.2 If not, please provide the FBCU's views on whether there is an appropriate portion of short-term debt for utilities without third-party debt.

Response:

Please refer to the response to BCUC IR 1.143.1.1.

143.2 How do the FBCU define "a very small component of a utility's overall capital structure" as a percentage of the overall capital structure?

Response:

In most circumstances, the bulk of a Utility's assets are in use and long-term in nature. This is highlighted in a scenario where there is no growth, where a Utility's short-term financing will only represent funds needed for working capital and represents a small portion of the debt financing mix. For example, short-term financing in FEI's capital structure averaged 4.6% at year-end over the past 5 years and reached a low of 0.1% and a high of 9.4% at year-end December 31 2011 and 2008, respectively . FBCU speculate that short-term financing (floating rate) could range from 0-10% as seasonality, gas prices, rates and capital expenditures impacts may vary the amount.

143.3 For each of the utilities within the FBCU group, i.e., FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., FortisBC Energy (Whistler) Inc., and FortisBC Inc., please complete the table below.

Name of Utility: [please insert name of utility]								
Years	**Short-Term Debt**		**Long-Term Debt**		**Common Equity**		**Preferred Shares**	
	Share of Capital Structure (%)	Interest Rate (%)	Share of Capital Structure (%)	Interest Rate (%)	Share of Capital Structure (%)	Allowed Cost of Equity	Share of Capital Structure (%)	Terms of Return (%)
2012								

2011							
…							
2002							

Response:

Please refer to the following tables:

Name of Utility: FortisBC Energy Inc.								
Years	Short-Term Debt		Long-Term Debt		Common Equity		Preferred Shares	
	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Allowed Cost of Equity (Approved)	Share of Capital Structure (%)	Terms of Return (%)
2012 (Approved)	1.93%	2.50%	58.07%	6.85%	40.00%	9.50%	0.00%	0.00%
2011	0.12%	4.50%	59.88%	6.95%	40.00%	9.50%	0.00%	0.00%
2010	1.24%	2.25%	58.76%	6.95%	40.00%	9.50%	0.00%	0.00%
2009	3.86%	4.25%	61.13%	6.96%	35.01%	8.99%	0.00%	0.00%
2008	9.41%	5.00%	55.58%	7.21%	35.01%	8.62%	0.00%	0.00%
2007	4.37%	4.75%	60.62%	7.02%	35.01%	8.37%	0.00%	0.00%
2006	6.33%	4.00%	58.67%	7.07%	35.00%	8.80%	0.00%	0.00%
2005	7.01%	4.00%	59.99%	7.26%	33.00%	9.03%	0.00%	0.00%
2004	9.97%	3.25%	57.03%	7.37%	33.00%	9.15%	0.00%	0.00%
2003	7.28%	4.00%	59.72%	7.56%	33.00%	9.42%	0.00%	0.00%
2002	6.53%	2.90%	60.47%	7.80%	33.00%	9.13%	0.00%	0.00%

Name of Utility: FortisBC Energy Inc. - Fort Nelson								
Years	Short-Term Debt		Long-Term Debt		Common Equity		Preferred Shares	
	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Allowed Cost of Equity (Approved)	Share of Capital Structure (%)	Terms of Return (%)
2012 (Approved)	2.44%	2.50%	57.56%	6.85%	40.00%	9.50%	0.00%	0.00%
2011	12.13%	4.50%	47.87%	6.95%	40.00%	9.50%	0.00%	0.00%
2010	5.66%	4.25%	54.34%	6.95%	40.00%	9.50%	0.00%	0.00%
2009	5.02%	4.25%	59.97%	6.96%	35.01%	8.99%	0.00%	0.00%
2008	7.31%	5.00%	57.68%	7.22%	35.01%	8.62%	0.00%	0.00%
2007	13.39%	3.25%	51.60%	7.37%	35.01%	8.37%	0.00%	0.00%
2006	10.93%	3.25%	54.07%	7.37%	35.00%	8.80%	0.00%	0.00%
2005	7.38%	3.25%	59.62%	7.37%	33.00%	9.03%	0.00%	0.00%
2004	8.52%	4.00%	58.48%	7.37%	33.00%	9.15%	0.00%	0.00%
2003	6.12%	4.00%	60.88%	7.56%	33.00%	9.42%	0.00%	0.00%
2002	15.52%	2.90%	51.48%	7.80%	33.00%	9.13%	0.00%	0.00%

Name of Utility: FortisBC Energy (Vancouver Island) Inc.

Years	Short-Term Debt		Long-Term Debt[1]		Common Equity		Preferred Shares	
	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Allowed Cost of Equity (Approved)	Share of Capital Structure (%)	Terms of Return (%)
2012 (Approved)	13.13%	4.00%	46.87%	5.73%	40.00%	10.00%	0.00%	0.00%
2011	5.13%	6.80%	54.87%	5.63%	40.00%	10.00%	0.00%	0.00%
2010	10.19%	4.23%	49.81%	4.62%	40.00%	10.00%	0.00%	0.00%
2009	11.04%	2.86%	48.96%	5.09%	40.00%	9.59%	0.00%	0.00%
2008	10.81%	5.20%	49.19%	5.98%	40.00%	9.32%	0.00%	0.00%
2007	3.81%	5.18%	56.19%	5.19%	40.00%	9.07%	0.00%	0.00%
2006	2.88%	4.86%	57.12%	4.91%	40.00%	9.50%	0.00%	0.00%
2005	18.45%	3.53%	46.55%	4.56%	35.00%	9.53%	0.00%	0.00%
2004	15.94%	2.13%	49.06%	5.12%	35.00%	9.65%	0.00%	0.00%
2003	14.35%	3.27%	50.65%	6.85%	35.00%	9.92%	0.00%	0.00%
2002	12.78%	2.40%	52.22%	7.62%	35.00%	9.25%	0.00%	0.00%

(1) The government loans to FEVI are treated as a credit to PPE and so are not shown as part of FEVI's capital structure.

Name of Utility: FortisBC Energy (Whistler) Inc.

Years	Short-Term Debt		Long-Term Debt		Common Equity		Preferred Shares	
	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Allowed Cost of Equity (Approved)[1]	Share of Capital Structure (%)	Terms of Return (%)
2012 (Approved)	11.76%	3.50%	48.24%	5.11%	40.00%	10.00%	0.00%	0.00%
2011	15.81%	5.15%	44.19%	5.11%	40.00%	10.00%	0.00%	0.00%
2010	15.95%	2.90%	44.05%	5.11%	40.00%	10.00%	0.00%	0.00%
2009	11.98%	5.10%	48.02%	5.93%	40.00%	9.49%	0.00%	0.00%
2008	17.34%	4.00%	47.66%	5.10%	35.00%	9.22%	0.00%	0.00%
2007	17.47%	4.00%	47.53%	5.10%	35.00%	8.97%	0.00%	0.00%
2006	18.05%	5.68%	46.95%	4.90%	35.00%	9.40%	0.00%	0.00%
2005	18.22%	3.27%	46.78%	5.10%	35.00%	9.75%	0.00%	0.00%
2004	17.51%	3.56%	47.49%	5.10%	35.00%	9.75%	0.00%	0.00%
2003	0.00%	0.00%	65.00%	4.70%	35.00%	10.02%	0.00%	0.00%
2002	0.00%	0.00%	65.00%	6.52%	35.00%	9.73%	0.00%	0.00%

(1) In 2006, the AAM produced a 9.40% approved ROE for FEW, however, the BCUC did not approve rates in 2006 and so 2005 rates were used (based on the approved 2005 ROE).

FortisBC Inc.								
Years	Short-Term Debt(1)		Long-Term Debt		Common Equity		Preferred Shares	
	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Allowed Cost of Equity (Approved)	Share of Capital Structure (%)	Terms of Return (%)
2012(2)	2.66%	2.89%	57.34%	5.92%	40.00%	9.90%	0.00%	0.00%
2011	0.09%	2.46%	59.91%	6.04%	40.00%	9.90%	0.00%	0.00%
2010	4.19%	2.87%	55.81%	6.18%	40.00%	9.90%	0.00%	0.00%
2009	2.09%	2.06%	57.91%	6.33%	40.00%	8.87%	0.00%	0.00%
2008	1.41%	3.38%	58.59%	6.36%	40.00%	9.02%	0.00%	0.00%
2007	3.16%	5.17%	56.84%	6.50%	40.00%	8.85%	0.00%	0.00%
2006	1.55%	4.82%	58.45%	6.49%	40.00%	9.20%	0.00%	0.00%
2005	6.30%	3.42%	53.70%	6.75%	40.00%	9.43%	0.00%	0.00%
2004	14.69%	4.82%	45.31%	7.07%	40.00%	9.55%	0.00%	0.00%
2003	12.81%	6.77%	47.19%	7.81%	40.00%	9.82%	0.00%	0.00%
2002	9.03%	6.11%	50.97%	7.76%	40.00%	9.53%	0.00%	0.00%

(1)With the exception of 2012, short-term interest rates above consider the weighted average rate of actual draws on the operating credit facility. All the above short-term interest rates do not include fixed financing fees such as banking agreement renewal charges, annual lender and agency fees, letter of credit fees or overdraft facility interest.

(2) 2012 and 2013 short-term and long-term interest rates and share of capital structure are representative of the most recent forecast that resulted from the 2012-2013 Revenue Requirements Decision from August 15, 2012. These forecasted figures have not yet been submitted to the Commission for approval, therefore these amounts are preliminary in nature.

143.4 Given the statement by the FBCU that short-term debt is used to fund working capital or when assets are in development, should there be a provision for short-term debt, even if only a 'very small component' in the deemed capital structure of FortisBC Alternative Energy Services Inc. (FAES)'s TES projects like Delta School District, Tsawwassen Springs Development and PCI Marine Gateway? Why or why not?

Response:

No. The FAES projects are small projects where most of the costs are upfront and there are not a lot of working capital requirements needed for things like seasonal fluctuations.

143.4.1 If so, what should the deemed short-term portion of the debt be? Why?

Response:

Please refer to the response to BCUC IR 1.143.4.

144.0 Reference: Debt Related Matters

Exhibit B1-9, Section 2.7, p. 31

Deemed Interest Rate for Short-Term Debt

On page 31, the FBCU state "The basis for determining the deemed interest rate for short-term debt would be similar to that of long-term interest rate noted above. It would be based on an indicative credit spread quotes from investment dealers or banks using comparable proxy issuers plus a short-term benchmark yield. A common benchmark yield in Canada is the Canadian Dealer Offered Rate ("CDOR"). CDOR is the quoted benchmark that is used when a company issues short-term Bankers' Acceptances, which reflects the short-term benchmark rate plus the company's applicable credit spread." (Emphasis added)

In Ms. McShane testimony on pages 127-128 (Exhibit B1-9-6, Appendix F), Ms. McShane states that "Three-month Bankers' Acceptances (BAs) are a common benchmark for establishing the cost of short-term debt for utilities, e.g., for credit facilities negotiated with banks, and would provide an appropriate basis for estimating a deemed short-term debt cost. … The average spread obtained from the banks would then be added to the three-month BA rate." [Emphasis added]

144.1 From the preamble above, please clarify whether the utility's credit spread is added twice given Ms. McShane's recommended formula given in (1) and the FBCU's description of the Bankers' Acceptance rate in (2)?

$$\text{ST debt rate} = \text{3monthBA rate} + \text{Credit Spread} \qquad (1)$$

$$\text{3monthBA rate} = \text{CDOR} + \text{Credit Spread} \qquad (2)$$

Response:

No, the credit spread is added only once in both cases. In Canada, the index of Bankers' Acceptance Rates for specific terms to maturity, including 3 months, is known as the Canadian Dealer Offer Rate, or CDOR. CDOR rates are determined by a daily survey of bid rates of the principal market-makers in Banker's Acceptances, which include the major Canadian investment banks. CDOR provides the basis for a floating reference rate in Canadian dollar transactions analogous to LIBOR. CDOR is thus effectively an average of Bankers' Acceptance (BA) Rates. The company-specific short-term rate can be expressed as the BA rate plus a credit spread or CDOR plus a credit spread.

144.1.1 Please clarify the generic formula that the FBCU would recommend using to calculate the deemed short-term interest rate if short-term debt is determined to be an appropriate part of the capital structure.

Response:

Either the 3-month CDOR or 3-month BA rate is reasonable. The latter is posted daily on the Bank of Canada website and is most readily verifiable.

144.2 How many comparable proxy issuers should be used to obtain the indicative credit spread quotes?

Response:

Quotes from banks would be obtained based on indicated credit rating, not by individual proxy issuer.

144.3 Should the same comparable proxy issuers be used for short-term and long-term credit spread? Why or why not?

Response:

As noted in response to BCUC IR 1.144.2, quotes would be obtained based on indicated credit rating, not by individual proxy issuer.

144.4 How many quotes from banks should be obtained in order to determine the indicative credit spread to be added to the benchmark rate?

Response:

The approach used by the OEB is reasonable. To estimate the short-term debt rate for Ontario Electricity Distributors, the OEB obtains up to six quotes. If it obtains six quotes, it discards the highest and the lowest and uses the average of the remaining four. If less than four are obtained, it uses the average of all the quotes it obtains.

OEB – Appendix D of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009 (Exhibit A2-21) and OEB – Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012 (Exhibit A2-22) explain the OEB's methodology to calculate the deemed short-term debt rate for Ontario's electricity distributors and transmitters.

144.5 If the Commission determines that short-term debt should be part of the deemed capital structure, please discuss the applicability of the OEB's methodology regarding the calculation of the deemed short-term debt rate for the deemed short-term debt component of the capital structure of BC utilities without third-party debt, such as FAES's TES projects (DSD, Tsawwassen Springs Development, PCI Marine Gateway) and other district energy systems (Corix UniverCity and River District Energy).

Response:

The formulaic approach taken by the OEB is an efficient way of estimating a deemed short-term debt rate for the types of utilities referenced in the question. However, the OEB methodology is premised on a single debt rating, a short-term debt rating of R1-low, which generally maps to long-term credit ratings in the A category, higher than would be applicable to the referenced small utilities in the information request above.

144.5.1 Specifically, what are the advantages and disadvantages of using this formula in the case of BC utilities without third-party debt?

Response:

The key advantages to the formula are its efficiency and transparency. The disadvantage is that it is based on an assumed credit rating that would not be applicable to the BC utilities that would most likely be affected if the Commission determines that deemed capital structures should include some component of short-term debt. That disadvantage can be overcome by specifying a more reasonable credit rating for affected utilities. e.g., BBB/BBB(low) on DBRS' long-term rating scale.

145.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, pp. 123

Deemed Debt Rate

On page 123, Ms. McShane states "[f]or small utilities which do not issue third-party debt, one option is to estimate the likely stand-alone credit rating for that utility. The stand-alone credit rating is based on an assessment of both the utility's business risk and financial risk as implied by the deemed common equity ratio."

145.1 Please describe "financial risk" from the above statement. Similar to the list and descriptions provided in Appendix H for business risks, list all the types of financial risks that would be applicable to a small utility in BC.

Response:

Financial risk in this context refers primarily to the deemed common equity ratio and the ability of the utility to cover its debt obligations from available cash flows from operations, measured by credit metrics such as an interest coverage ratio. The inclusion of financial risks in the determination of the most likely credit rating recognizes that credit ratings are a function of the ability to repay debt obligations, which, in turn, are a function of the capital structure (and ROE).

146.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, Section IX, p. 122

Applicable Circumstances for Deemed Capital Structure with Deemed Debt

On page 122, Ms. McShane states "A deemed cost of debt may be warranted where it is inefficient or uneconomic for a small utility to issue debt on a stand-alone basis. The small utility could be a separate legal entity, or a standalone division or distinct class of service. Where there has been actual debt issued by the legal entity in which the utility operation (e.g., a distinct class of service) resides, but the business risk profiles of the issuer and the specific utility operation (be it a separate legal entity, regulated division or distinct class of service) are materially different, a deemed cost of debt for that utility operation that differs from the issuer's cost of debt may be warranted. In such cases, the deeming of a utility-specific cost of debt is intended to ensure, consistent with the stand-alone principle, that there are no cross-subsidies among the operations of the firm. An appropriate deemed cost of debt for the regulated operation may be higher or lower than the cost of debt that is actually incurred by the issuer, i.e., the regulated operation may face higher or lower business risk than the issuer." [Emphasis added]

146.1 With respect to any of the FBCU, please list all existing 'separate legal entity, standalone division, distinct class of service or project' that would fit the above definition of 'small utility'. Please provide a short description of each case listed including, but not limited to, the business risk profiles of the issuer versus the specific utility operation, the credit rating of the issuer versus the deemed credit rating of the specific utility operation.

Response:

With respect to the FBCU, the entities would be FEW, which is a separate legal entity, Fort Nelson, which is a distinct division of FEI, and the Delta School District and Tsawwassen Springs which are approved projects. The FBCU understand that Phase I of this GCOC is addressing the deemed debt issue at the level of principles, i.e. whether a deemed debt should be employed for utilities without third party debt, in what circumstances, and how deemed debt rates might be determined, rather than determining the deemed debt rate etc. for specific entities that are not Affected Utilities. The FBCU respectfully submit that the matters such as the risk profile of these entities and the credit rating of the issuers (if any) are thus most appropriately addressed in Phase II of the GCOC.

146.1.1 In particular, do the following FEI/FAES projects fit this definition of 'small utility': Delta School District No. 37, Tsawwassen Springs Development, PCI Martine Gateway? Why or why not?

Response:

Yes, Delta School and Tsawwassen Springs are small utilities given their very small capital base. Note that PCI Marine has not yet been approved, but if it is, it as well will be a small utility. Each is less than $10 million in capital.

Ms. McShane also states on page 122 that "While, as discussed below, there are common approaches that the Commission can rely upon for the specific utilities to which a deemed debt cost might apply, the number of potentially affected utilities is relatively small,145 and the need to approve a deemed cost of debt relatively infrequent. The individual utilities' circumstances may be different, in terms of risk, the funding requirements and appropriate terms of debt. As a result, I recommend that the Commission continue to address the cost of debt for each utility separately.

[145] In contrast to Ontario, where the OEB, which has adopted a formula for establishing caps on the cost rates of affiliated debt, is charged with regulating close to 80 municipally-owned electric distribution utilities."

On page 55, Ms. McShane submits that "The principal change that has occurred since the 2009 Application relates to <u>increased regulatory lag</u> and uncertainty that stem largely from the changing energy environment, particularly for natural gas. <u>More FEI activities, focused on new initiatives, are subject to regulatory oversight, entailing more frequent, protracted, and contentious proceedings.</u>"

146.2 Given that the Commission directed that a deemed debt cost be calculated in four applications within the last 16 months (i.e., Corix UniverCity, River District Energy, FAES Delta School District No. 37, Tsawwassen Springs Development) and is currently reviewing this issue in FAES's PCI Marine Gateway application, and in light of the many thermal energy services (TES) applications by FEI/FAES expected to be filed before the end of 2012, would the FBCU still describe the need to approve a deemed cost of debt as 'relatively infrequent'? Why or why not?

Response:

Yes, the FBCU still believes that the situation is relatively infrequent. The debt cost determination is being made concurrent with approval of the projects and is not expected to be an annual determination as the debt approved is typically term debt.

146.3 Do the FBCU agree that addressing the cost of debt for each utility separately may be one of the contributing factors to the increased regulatory lag, which may be reduced if the deeming of the cost of debt was streamlined for utilities without third-party debt through the use of a formula like in Ontario? Why or why not?

Response:

No the FBCU do not agree. The cost of debt, as noted in response to BCUC IR 1.146.2, is part of the project approval application so in and of itself is not contributing significantly to the added regulatory work.

146.4 In Ms. McShane's opinion, how many small utilities without third-party debt would the Commission need to regulate before it becomes more efficient to adopt an interest automatic adjustment mechanism?

Response:

Ms. McShane did not have a specific number in mind, but considers that the circumstances in BC as regards the use of a deemed debt rate are quite different from those in Ontario, the only jurisdiction to have implemented a formula for setting a deemed cost of debt. In Ontario, a formula for setting the cost of affiliate debt was adopted in 2006, when there just under 90 electricity distributors in the province. There are currently 78. For each of these distributors, the OEB needs to establish all elements of its revenue requirements, and to do so each time the utility's rates are rebased. Currently, the utilities are on a four year rates cycle. This means that the OEB needs to address 20 revenue requirements applications every year for the electricity distributors alone, including resetting the cost of any existing affiliate and deemed debt and setting the cost of forecast affiliate and deemed debt. In contrast, in BC, for TES projects, the Commission needs to establish the cost of debt much less frequently. For example, in the case of the FAES Delta School District No. 37 project, the term of the deemed debt is 20 years. In

Ms. McShane's opinion, the circumstances in BC make the case for a formula to set a deemed cost of debt much less compelling.

146.4.1 Given provincial and municipal government policies in BC that are favourable to the development of thermal energy services delivered through district or discreet energy systems, how long do the FBCU anticipate it could be before the Commission reaches this threshold number of small utilities without third-party debt?

Response:

The FBCU do not have a threshold number of utilities in mind. The issue is relevant if the utilities have debt costs that are revisited annually or on a relatively frequent basis. To date in BC, that does not appear to be the case as the debt being approved in the case of FBCU affiliated projects will be term debt.

147.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, Section IX, p. 123

Appropriate Basis to Calculate a Deemed Interest Rate

Ms. McShane states that "For small utilities which do not issue third-party debt, one option is to estimate the likely standalone credit rating for that utility. The stand-alone credit rating is based on an assessment of both the utility's business risk and financial risk as implied by the deemed common equity ratio."

147.1 In practice, how would Ms. McShane proceed to estimate the likely standalone credit rating for a small utility without third party debt based on the utility's business and financial risk? Please explain the steps in detail.

Response:

In Ms. McShane's opinion, pinpointing a credit rating for the small utilities does not lend itself to a step-by-step process, in part because there are no rated proxies for these small utilities, as Ms. McShane noted in response to BCUC IR 1.139.5, that could be used as benchmarks. Consequently, estimating their stand-alone credit rating is inherently a less objective process than it would be for a large utility with rated peers. Ms. McShane considers that there are four key factors that should be considered with respect to the small utilities: (1) they all operate in the same economic environment and energy policy environment as the benchmark utility, FEI; (2) they are all regulated; (3) they are very small; and (4) their equity ratios are likely to be within the range of equity ratios adopted for other Canadian utilities. As they are regulated, it would be reasonable to proceed on the premise that, in theory, they could all be considered to be investment grade. The fact that they are very small, with the inherent risks of small size set out in response to BCUC IR 1.139.5, would preclude them from achieving ratings equal to those of the benchmark. A reasonable deemed stand-alone rating for a small, but regulated, utility is in the range of BBB to BBB(low), with the deemed debt cost set on this basis. In this regard, this is effectively the approach that the Régie uses to set the cost of debt that Gazifère (a gas distribution utility with an approximately $70 million rate base) issues to its parent Enbridge Inc. Gazifère obtains a letter from one of the major investment banks when it issues new affiliate debt. The letter sets out the estimated cost of debt for a new issue for Gazifère as a BBB/BBB(low) utility. That estimated cost forms the basis of the cost approved by the Régie.

147.1.1 How can this credit rating be estimated as objectively as possible?

Response:

Please refer to the response to BCUC IR 1.147.1.

148.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, Section IX, pp. 123-124

Term of Bond for Deemed Interest Rate

On pages 123-124 of Ms. McShane's testimony, Ms. McShane states that three other considerations should be taken into account, besides the fact that the term should reflect the long-term nature of the assets: 1) the term of the contractual arrangements; 2) the limitations of what would reasonably be available to operations with a similar risk profile; and 3) the state of the capital markets.

148.1 In what priority order should these considerations be taken into account?

Response:

Ms. McShane considers that the term of the contract should be the first consideration, as a lender would look to the commitments made by customers in its determination of the term of a loan it was willing to extend. The state of the capital markets should be a supplementary check on the reasonableness of the deemed term of the debt, as a protection to the customers who bear the cost. If utilities that would normally raise debt in the public markets are not able to raise long-term debt on reasonable terms and conditions due to capital market conditions, it would not be reasonable to allow small utilities to charge deemed long-term debt rates which reflect those same capital market conditions.

148.2 If the contract has a term of 20 years but "the specific operations has a level of risk such that the utility would not be able to obtain "real" debt on terms longer than 10 years,…..", what should the appropriate term of the deemed long-term debt be?

Response:

As noted in response to BCUC IR 1.148.1, the term of the contract should be the first consideration. As a practical matter, the spreads between 10-year and 30-year utility debt are relatively small. To illustrate, based on U.S. utility data, the average difference in the spread for 10-year and 30-year BBB(low)/Baa3 rated utility debt between 2007 and 2012 has been approximately 33 basis points.

148.3 Similarly, if the contract has a term of 20 years but the debt market would not accommodate a long-term issue, as during a financial crisis, what should the appropriate term of the deemed long-term debt be?

Response:

In Ms. McShane's opinion, if the situation were to arise, the Commission should rely on what term utilities actually raising debt capital in the public markets are able to obtain. For example, during the financial crisis, when long-term debt was either unavailable or determined to be too expensive, several utilities raised debt with a five-year term.

149.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, Section IX, p. 125

Deemed Capital Structure and Credit Spreads

On page 125, Ms. McShane states that "At a high level, for a utility with a given level of business risk, the higher the deemed equity ratio is, the less risk there is to bondholders, and thus, the lower the credit spread. The credit spread (market conditions and term to maturity aside) for a real issue will also be a function of the actual debt covenants (e.g., whether the debt issue is an amortizing issue or a "bullet" issue) as well as a function of other factors that determine the available cash flows (e.g., the level of ROE and non-cash expenses, particularly depreciation). There is, however, no formulaic method for determining the [sic] how the credit spread will change for a given change in common equity ratio."

149.1 When obtaining indicative credit spreads from comparable proxy issuers, is there a need to adjust the credit spreads based on differences in capital structure, ROE, depreciation, actual debt covenants or other factors? Why or why not?

Response:

Please note that the referenced discussion was in response to a Commission filing requirement which asked how the deemed capital structure related to credit spreads. The discussion in Ms. McShane's evidence was intended simply to point out that there are multiple factors that will determine actual credit spreads for utility issuers, one of which is deemed capital structure.

It would be sufficient, in Ms. McShane's view, to rely on a spread that is reasonable and appropriate for proxy issuers in the rating category assigned to the utility. There is no practical way to adjust indicated spreads for all the various factors identified in the question.

149.1.1 If so, how should the adjustment be made? Why?

Response:

Please refer to the response to BCUC IR 1.149.1.

150.0 Reference: Testimony on Cost of Capital for the FBCU by Ms. McShane

Exhibit B1-9-6, Appendix F, Section IX, p. 125-127

Appropriate Portions of Short-Term and Long-Term Debt

On page 126, Ms. McShane states that "The OEB deemed a standard deemed short-term debt component for the electricity distributors on the grounds that (1) it was clear that distributors used some short-term debt; (2) short-term debt is generally less expensive than long-term debt and generally provides greater financing flexibility; and (3) while actual short-term debt percentages may seem to be a more accurate approach, it is administratively challenging given the number of electricity distributors regulated by the OEB. The 4% deemed short-term debt component that the OEB settled on in 2006 represented the actual Ontario electricity distribution industry average at the time."

On page 127, Ms. McShane concludes "Nevertheless, the utility industry data available indicate that the deemed percentage of short-term debt should be very small, e.g., 1% to 2% percent."

150.1 Do the FBCU agree that, in the Ontario case, the OEB chose to determine the standard deemed short-term debt component for the electricity distributors based on the actual Ontario electricity distribution industry average at the time and not based on Canadian utility industry data?

Response:

Confirmed. As stated in the OEB's 2006 *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (December 20, 2006) cited by Ms. McShane Exhibit B1-9-6, Appendix F, Section IX, page 126:

"The Board has determined that short-term debt should be factored into rate setting, and that a deemed amount should be included in the capital structures of electricity distributors. ***The short-term debt amount will be fixed at 4% of rate base****.*

Based on filings of distributors pursuant to the Board's Electricity RRR and in 2006 rate applications, it is clear that many distributors use short-term debt. The actual average for the industry is about 4%." [page 9, emphasis in original]

150.2 What is the rationale for looking at the broader Canadian utility industry data to determine an appropriate deemed short-term component for BC utilities without third-party debt?

Response:

The purpose was to underscore how variable the short-term debt component of the capital structures of utilities is and to explain why it might vary so much, making it difficult to identify one specific short-term debt component appropriate for all. That variability was also demonstrated for the Ontario electricity distribution sector. As Ms. McShane stated at lines 3237 to 3238, "[t]he 4% deemed short-term debt component that the OEB selected does not capture the wide utility-by-utility variation or annual changes in the industry average."

150.3 Please discuss the pros and cons of looking only at the BC utilities with rated debt as a reference point to calculate an appropriate deemed short-term component for BC utilities without third-party debt.

Response:

The main disadvantage is that there are only three BC utilities which have had rated debt and with publicly available financial statements (FEI, FBC and PNG). The resulting sample is very small and thus prone to undue influence by individual company-specific circumstances.

150.3.1 Please calculate the average and median proportion of short-term debt to total capital for all BC utilities with rated debt in each of the last five years (2007 to 2011).

Response:

The 2007-2011 averages and medians for FEI, FBC and PNG are as follows:

	2007	2008	2009	2010	2011	Average/ Median 2007-2011	Average of Annual Medians
Average	3.6	4.6	1.7	1.8	1.6	2.7	
Median	1.5	4.3	0.4	1.6	1.8	1.6	1.9

150.4 Does Schedule 5, page 2 of 2 contain an exhaustive list of all the Canadian utilities with rated debt? If not, which utilities were excluded and what were the criteria for inclusion in or exclusion from the list in Schedule 5? For the purposes of responding to the MFR question: "What is an appropriate portion of short-term debt and long-term debt on the debt portion of the deemed capital structure?" should all Canadian utilities with rated debt be used to calculate the average proportion of short-term debt to total capital? If not, why not?

Response:

No. Schedule 5, page 2 of 2 includes only the investor-owned utilities from Schedule 5, page 1 of 1 whose financial statements were publicly-available (i.e., FEVI was not included). Ms. McShane did not include the municipally owned utilities with rated debt, most of whom are Ontario electricity distributors, because, as stated at lines 3241 to 3244, "Moreover, inasmuch as the other components of the Ontario distribution utilities' reported actual capital structures deviated materially from the deemed proportions, using the industry average short-term debt ratio to set the deemed component is questionable."

150.5 Do the FBCU agree that short-term debt is generally less expensive than long-term debt? Generally, by how much?

Response:

Yes. The FBCU is aware that in the government bond/treasury market, which acts as the underlying benchmark risk free rate for corporate issuers, it has been observed historically that the yield curve (the relationship between long-term yields and short-term yields on government bonds/treasuries) varies over time and that the most common relationship is one where the higher the maturity the greater the yield or an upward sloping yield curve – and hence short-term debt is cheaper.

The differential between short and long term debt varies so there is no constant relationship. Currently, on an indicative basis, FEI can borrow 3-month commercial paper at approximately 1.3%, while an indicative 30-year bond yield would be approximately 4.0%, for a differential of 2.7%.

150.5.1 To the extent that short-term debt is determined to be an appropriate part of the capital structure, and if it is true that short-term debt is less expensive than long-term debt, do the FBCU agree that a deemed cost of short-term debt is warranted for the short-term debt? If not, why not?

Response:

With respect to the smaller utilities without short term debt in their capital structure, to the extent such debt is deemed to form part of the capital structure, then, similar to long term debt, a deemed cost of debt would be appropriate.

150.6 Please comment on the relationship between working capital, which is a component of rate base, and the short-term debt component of the capital structure.

Response:

There is no direct relationship. Working capital is comprised, in the case of FEI, of cash working capital, gas-in storage, transmission line pack, inventory and construction advances. Cash working capital represents the average amount of capital provided by investors to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. For FEI, in recent years, cash working capital requirements have been negative. While working capital is literally comprised of assets that, for accounting purposes, are defined as short-term, working capital represents a permanent component of the utility's rate base and, as such, does not correspond to the proportion of short-term debt that would be appropriate for deemed capital structure purposes.

Attachment 14.3.1

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. ***Information has been incorporated by reference in this prospectus from documents filed with securities commissions or similar authorities in Canada.*** *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of CU Inc. at 1400 ATCO Centre, 909 - 11th Avenue S.W., Calgary, Alberta T2R 1N6 (telephone: (403) 292-7500), and are also available electronically at www.sedar.com.*

Short Form Prospectus

New Issue **November 24, 2010**

CU INC.
An ATCO Company

$75,000,000
(3,000,000 shares)
Cumulative Redeemable Preferred Shares Series 4

The holders of the Cumulative Redeemable Preferred Shares Series 4 (the "Series 4 Preferred Shares") of CU Inc. (the "Corporation") will be entitled to receive, as and when declared by the board of directors of the Corporation, fixed cumulative preferential cash dividends for the initial period (the "Initial Fixed Rate Period") from and including the closing date of this offering to but excluding June 1, 2016, at an annual rate of $0.95 per share, payable quarterly on the first day of March, June, September and December in each year. Assuming an issue date of December 2, 2010, the first dividend, if declared, will be payable March 1, 2011, in the amount of $0.23164 per share.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of the Series 4 Preferred Shares shall be entitled to receive, as and when declared by the board of directors of the Corporation, fixed cumulative preferential cash dividends, payable quarterly on the first day of March, June, September and December in each year, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00. The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by the Corporation on the Fixed Rate Calculation Date (as defined herein) and will be equal to the sum of the Government of Canada Yield (as defined herein) on the Fixed Rate Calculation Date plus a spread of 1.36% (the "Spread"). This Spread will apply to both the Series 4 Preferred Shares and the Series 5 Preferred Shares described below, and will remain unchanged over the life of the Series 4 Preferred Shares and the Series 5 Preferred Shares. See "Details of the Offering".

Option to Convert Into Series 5 Preferred Shares

The holders of the Series 4 Preferred Shares will have the right to convert their shares into Cumulative Redeemable Preferred Shares Series 5 of the Corporation (the "Series 5 Preferred Shares"), subject to certain conditions, on June 1, 2016, and on June 1 in every fifth year thereafter. The holders of the Series 5 Preferred Shares will be entitled to receive, as and when declared by the board of directors, quarterly floating rate cumulative preferential cash dividends payable on the first day of March, June, September and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period") in the amount per share determined by multiplying the Floating Quarterly Dividend Rate (as defined herein) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate (as defined herein) on the applicable Floating Rate Calculation Date (as defined herein) and 1.36%. See "Details of the Offering".

On June 1, 2016, and on June 1 in every fifth year thereafter, the Corporation may, at its option on not less than 30 days prior notice, redeem for cash the Series 4 Preferred Shares, in whole at any time or in part from time to time, at $25.00 per share together with all accrued and unpaid dividends to but excluding the date of redemption.

The Toronto Stock Exchange (the "TSX") has conditionally approved the listing of the Series 4 Preferred Shares and the Series 5 Preferred Shares. Listing of the Series 4 Preferred Shares is subject to the Corporation fulfilling all of the requirements of the TSX on or before February 14, 2011, including distribution of these securities to a minimum number of public securityholders. In the opinion of counsel, subject to the provisions of any particular plan, the Series 4 Preferred Shares and the Series 5 Preferred Shares, if issued on the date hereof, generally would be qualified investments under the *Income Tax Act* (Canada) (the "Tax Act") for certain tax-exempt trusts. See "Eligibility for Investment". The head and registered office of the Corporation is at 1400 ATCO Centre, 909 – 11th Avenue S.W., Calgary, Alberta T2R 1N6.

Price: $25.00 per share to yield 3.80% per annum

	Price to Public	**Underwriters' Fee (1)**	**Proceeds to Corporation (1)**
Per Series 4 Preferred Share	$25.00	$0.75	$24.25
Total..	$75,000,000	$2,250,000	$72,750,000

Note:

(1) The Underwriters' Fee for the Series 4 Preferred Shares is $0.25 for each such share sold to certain institutions by closing of the offering and $0.75 per share for all other Series 4 Preferred Shares purchased by the Underwriters. The Underwriters' Fee indicated in the table assumes that no Series 4 Preferred Shares are sold to such institutions.

BMO Nesbitt Burns Inc., RBC Dominion Securities Inc. and TD Securities Inc. (the "Underwriters"), as principals, conditionally offer the Series 4 Preferred Shares, subject to prior sale, if, as and when issued by the Corporation and accepted by the Underwriters in accordance with the conditions contained in the Underwriting Agreement referred to under "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation by Bennett Jones LLP and on behalf of the Underwriters by Blake, Cassels & Graydon LLP. The Underwriters may over-allot or effect transactions that stabilize or maintain the market price of the Series 4 Preferred Shares. See "Plan of Distribution".

Subscriptions will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the closing of this offering will take place on or about December 2, 2010, and in any event not later than December 23, 2010. A book-entry only certificate representing the Series 4 Preferred Shares distributed hereunder will be issued in registered form only to The Canadian Depository for Securities Limited ("CDS") or its nominee and will be deposited with CDS on the closing of this offering. The Corporation understands that a purchaser of Series 4 Preferred Shares will receive only a customer confirmation from the registered dealer who is a CDS participant and from or through whom Series 4 Preferred Shares are purchased.

The Underwriters are subsidiaries of Canadian chartered banks which have extended credit facilities to the Corporation and certain of its affiliates. Accordingly, under certain circumstances, the Corporation may be considered a "connected issuer" of the Underwriters under applicable securities legislation. See "Plan of Distribution".

TABLE OF CONTENTS

DOCUMENTS INCORPORATED BY REFERENCE

The following documents of the Corporation are specifically incorporated by reference in this short form prospectus:

(a) annual information form dated February 17, 2010;

(b) comparative consolidated financial statements, together with the accompanying report of the auditor, for the year ended December 31, 2009;

(c) management's discussion and analysis for the year ended December 31, 2009;

(d) unaudited comparative consolidated financial statements for the nine months ended September 30, 2010; and

(e) management's discussion and analysis for the nine months ended September 30, 2010;

provided that these documents are not incorporated by reference to the extent their contents are modified or superseded by a statement contained in this short form prospectus or in any other subsequently filed document that is also incorporated by reference in this short form prospectus.

Any documents of the type described in section 11.1 of Form 44-101F1 - *Short Form Prospectus*, if filed by the Corporation after the date of this short form prospectus and before the termination of the distribution, are deemed to be incorporated by reference in this short form prospectus.

Any statement contained in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of this short form prospectus to the extent that a statement contained herein, or in any other subsequently filed document which also is incorporated or is deemed to be incorporated by reference herein, modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed an admission for any purpose that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this short form prospectus.

BUSINESS OF THE CORPORATION

The Corporation is a holding company. Its principal operating subsidiaries are engaged in regulated natural gas and electric energy operations, primarily in Alberta.

RECENT DEVELOPMENTS

On November 18, 2010, the Corporation issued $125,000,000 of 4.947% Debentures maturing November 18, 2050.

CAPITALIZATION

The following table sets out the consolidated capitalization of the Corporation as at December 31, 2009, and as at September 30, 2010, before and after giving effect to this offering and the issue on November 18, 2010, of $125,000,000 of 4.947% Debentures maturing November 18, 2050. The financial information set out below should be read in conjunction with the Corporation's comparative consolidated financial statements incorporated by reference in this short form prospectus.

($ Millions)	**As at December 31, 2009**	**As at September 30, 2010**	**Pro Forma as at September 30, 2010**
Long term debt:			
Outstanding	2,827.4	2,703.1	2,703.1
4.947% Debentures due November 18, 2050 (1)	-	-	125.0
Total long term debt	2,827.4	2,703.1	2,828.1
Preferred shares:			
Outstanding	405.0	405.0	405.0
Series 4 Preferred Shares	-	-	75.0
Total preferred shares	405.0	405.0	480.0
Class A and Class B share owner's equity	2,038.8	2,243.4	2,243.4
Total capitalization	5,271.2	5,351.5	5,551.5

Note:
(1) Issued November 18, 2010.

USE OF PROCEEDS

The estimated net proceeds (after deducting the Underwriters' Fee) to be received by the Corporation from the sale of the Series 4 Preferred Shares are $72,750,000, assuming that no Series 4 Preferred Shares are sold to institutions. The Corporation intends to use the proceeds to purchase preferred shares to be issued by its operating subsidiaries, ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd. It is expected that these subsidiaries will use the proceeds to fund a portion of their 2010 capital expenditure programs.

DETAILS OF THE OFFERING

Definition of Terms

The following definitions are relevant to the Series 4 Preferred Shares and the Series 5 Preferred Shares.

"Annual Fixed Dividend Rate" means, for any Subsequent Fixed Rate Period, the annual rate of interest (expressed as a percentage rounded to the nearest one hundred–thousandth of one percent (with 0.000005% being rounded up)) equal to the sum of the Government of Canada Yield on the applicable Fixed Rate Calculation Date and 1.36%.

"Dividend Payment Date" means March 1, June 1, September 1 or December 1 in any year;

"Fixed Rate Calculation Date" means, for any Subsequent Fixed Rate Period, the 30th day prior to the first day of such Subsequent Fixed Rate Period.

"Floating Quarterly Dividend Rate" means, for any Quarterly Floating Rate Period, the annual rate of interest (expressed as a percentage rounded to the nearest one hundred-thousandth of one percent (with 0.000005% being rounded up)) equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date and 1.36%.

"Floating Rate Calculation Date" means, for any Quarterly Floating Rate Period, the 30th day prior to the first day of such Quarterly Floating Rate Period.

"Government of Canada Yield" on any date means the yield to maturity on such date (assuming semi-annual compounding) of a Canadian dollar denominated non-callable Government of Canada bond with a term to maturity of five years as quoted as of 10:00 a.m. (Toronto time) on such date and that appears on the Bloomberg Screen GCAN5YR Page on such date; provided that if such rate does not appear on the Bloomberg Screen GCAN5YR Page on such date, then the Government of Canada Yield shall mean the arithmetic average of the yields quoted to the Corporation by two registered Canadian investment dealers selected by the Corporation as being the annual yield to maturity on such date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on such date with a term to maturity of five years.

"Initial Fixed Rate Period" means the period from and including the date of issue of the Series 4 Preferred Shares to but excluding June 1, 2016.

"Quarterly Commencement Date" means the first day of March, June, September and December in each year, commencing March 1, 2011.

"Quarterly Floating Rate Period" means the period from and including a Quarterly Commencement Date to but excluding the next succeeding Quarterly Commencement Date.

"Series 4 Conversion Date" means June 1, 2016, and June 1 in every fifth year thereafter.

"Series 5 Conversion Date" means June 1, 2021, and June 1 in every fifth year thereafter.

"Subsequent Fixed Rate Period" means, for the initial Subsequent Fixed Rate Period, the period from and including June 1, 2016, to but excluding June 1, 2021, and for each succeeding Subsequent Fixed Rate Period means the period from and including the day immediately following the last day of the immediately preceding Subsequent Fixed Rate Period to but excluding June 1 in the fifth year thereafter.

"T-Bill Rate" means, for any Quarterly Floating Rate Period, the average yield expressed as an annual rate on three-month Government of Canada treasury bills, as reported by the Bank of Canada, for the most recent treasury bills auction preceding the applicable Floating Rate Calculation Date.

Certain Provisions of the Series 4 Preferred Shares

Issue Price

The Series 4 Preferred Shares will have an issue price of $25.00 per share.

Dividends on Series 4 Preferred Shares

During the Initial Fixed Rate Period, the holders of the Series 4 Preferred Shares shall be entitled to receive and the Corporation shall pay, as and when declared by the board of directors, out of the moneys of the Corporation properly applicable to the payment of dividends, fixed cumulative preferential cash dividends at an annual rate of $0.95 per share, payable quarterly on each Dividend Payment Date in each year. The first dividend, if declared, shall be payable on March 1, 2011, and, notwithstanding the foregoing, shall be in the amount per share determined by multiplying $0.95 by the number of days in the period from and including the date of issue of the Series 4 Preferred Shares to but excluding March 1, 2011, and dividing that product by 365.

During each Subsequent Fixed Rate Period, the holders of the Series 4 Preferred Shares shall be entitled to receive and the Corporation shall pay, as and when declared by the board of directors, out of the moneys of the Corporation properly applicable to the payment of dividends, fixed cumulative preferential cash dividends, payable quarterly on each Dividend Payment Date, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00.

On each Fixed Rate Calculation Date, the Corporation shall determine the Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period. Each such determination shall, in the absence of manifest error, be final and binding upon the Corporation and upon all holders of Series 4 Preferred Shares. The Corporation shall, on each Fixed Rate Calculation Date, give written notice of the Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period to the registered holders of the then outstanding Series 4 Preferred Shares.

Redemption of Series 4 Preferred Shares

The Series 4 Preferred Shares shall not be redeemable prior to June 1, 2016. Subject to the provisions described under “Restrictions on Payments and Reductions of Capital”, on June 1, 2016, and on June 1 in every fifth year thereafter, the Corporation, may redeem all or any part of the Series 4 Preferred Shares by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption.

Notice of any redemption of Series 4 Preferred Shares will be given by the Corporation not more than 60 days and not less than 30 days prior to the date fixed for redemption. If less than all of the outstanding Series 4 Preferred Shares are at any time to be redeemed, the shares to be redeemed will be selected pro rata disregarding fractions or in such other manner as the Corporation may determine.

Conversion of Series 4 Preferred Shares into Series 5 Preferred Shares

The Series 4 Preferred Shares shall not be convertible prior to June 1, 2016. Holders of Series 4 Preferred Shares shall have the right to convert on each Series 4 Conversion Date, subject to restrictions on conversion described below and the payment or delivery to the Corporation of evidence of payment of any tax payable, all or any of their Series 4 Preferred Shares into Series 5 Preferred Shares on the basis of one Series 5 Preferred Share for each Series 4 Preferred Share. Notice of a holder’s intention to convert Series 4 Preferred Shares must be received by the transfer agent and registrar for the Series 4 Preferred Shares at its principal office in Toronto not earlier than the 30th day prior to, but not later than 5:00 p.m. (Toronto time) on the 15th day preceding, a Series 4 Conversion Date.

The Corporation shall, not more than 60 days and not less than 30 days prior to the applicable Series 4 Conversion Date, give notice to the then registered holders of the Series 4 Preferred Shares of the conversion right. On the 30th day prior to each Series 4 Conversion Date, the Corporation shall give notice to the then registered holders of the Series 4 Preferred Shares of the Annual Fixed Dividend Rate for the Series 4 Preferred Shares for the next succeeding Subsequent Fixed Rate Period and the Floating Quarterly Dividend Rate for the Series 5 Preferred Shares for the next succeeding Quarterly Floating Rate Period.

Holders of Series 4 Preferred Shares shall not be entitled to convert their shares into Series 5 Preferred Shares if the Corporation determines that there would remain outstanding on a Series 4 Conversion Date less than 1,000,000 Series 5 Preferred Shares, after having taken into account all Series 4 Preferred Shares tendered for conversion into Series 5 Preferred Shares and all Series 5 Preferred Shares tendered for conversion into Series 4 Preferred Shares. The Corporation shall give notice thereof to all affected registered holders of the Series 4 Preferred Shares at least seven days prior to the applicable Series 4 Conversion Date. Furthermore, if the Corporation determines that there would remain outstanding on a Series 4 Conversion Date less than 1,000,000 Series 4 Preferred Shares, after having taken into account all Series 4 Preferred Shares tendered for conversion into Series 5 Preferred Shares and all Series 5 Preferred Shares tendered for conversion into Series 4 Preferred Shares, then all of the remaining outstanding Series 4 Preferred Shares shall be converted automatically into Series 5 Preferred Shares on the basis of one Series 5 Preferred Share for each Series 4 Preferred Share on the applicable Series 4 Conversion Date and the Corporation shall give notice thereof to the then registered holders of such remaining Series 4 Preferred Shares at least seven days prior to the Series 4 Conversion Date.

The Corporation reserves the right not to deliver Series 5 Preferred Shares to any person that the Corporation or its transfer agent has reason to believe is a person whose address is in, or that the Corporation or its transfer agent has reason to believe is a resident of, any jurisdiction outside Canada if such delivery would require the Corporation to take any action to comply with the securities laws of such jurisdiction.

If the Corporation gives notice to the holders of the Series 4 Preferred Shares of the redemption of all of the Series 4 Preferred Shares, the right of a holder of Series 4 Preferred Shares to convert such Series 4 Preferred Shares shall terminate and the Corporation shall not be required to give notice to the registered holders of the Series 4 Preferred Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series 4 Preferred Shares.

Purchase for Cancellation

Subject to the provisions described under "Restrictions on Payments and Reductions of Capital", the Corporation may at any time or times purchase for cancellation all or any part of the Series 4 Preferred Shares at the lowest price or prices at which, in the opinion of the board of directors of the Corporation, such shares are obtainable.

Rights on Liquidation

In the event of the liquidation, dissolution or winding-up of the Corporation or any other distribution of assets of the Corporation among its shareholders for the purpose of winding up its affairs, the holders of the Series 4 Preferred Shares shall be entitled to receive $25.00 per Series 4 Preferred Share plus all accrued and unpaid dividends thereon before any amount shall be paid or any property or assets of the Corporation shall be distributed to the holders of the Class A non-voting shares or Class B common shares or to the holders of any other shares ranking junior to the Series 4 Preferred Shares in any respect. After payment to the holders of the Series 4 Preferred Shares of the amount so payable to them, they shall not, as such, be entitled to share in any further distribution of the property or assets of the Corporation.

Restrictions on Payments and Reductions of Capital

So long as any Series 4 Preferred Shares are outstanding, the Corporation shall not

(a) call for redemption, purchase, reduce or otherwise pay off less than all the Series 4 Preferred Shares and all other preferred shares then outstanding ranking prior to or on a parity with the Series 4 Preferred Shares with respect to payment of dividends,

(b) declare, pay or set apart for payment any dividends (other than stock dividends in shares of the Corporation ranking junior to the Series 4 Preferred Shares) on the Class A non-voting shares or Class B common shares or any other shares of the Corporation ranking junior to the Series 4 Preferred Shares with respect to payment of dividends, or

(c) call for redemption, purchase, reduce or otherwise pay off any shares of the Corporation ranking junior to the Series 4 Preferred Shares with respect to repayment of capital or with respect to payment of dividends

unless all dividends up to and including the dividends payable on the last preceding dividend payment dates on the Series 4 Preferred Shares and on all other preferred shares then outstanding ranking prior to or on a parity with the Series 4 Preferred Shares with respect to payment of dividends shall have been declared and paid or set apart for payment at the date of any such action.

Creation or Issue of Additional Shares

So long as any Series 4 Preferred Shares are outstanding, the Corporation shall not, without the prior approval of the holders of the Series 4 Preferred Shares, create or issue any shares ranking prior to or on a parity with the Series 4 Preferred Shares with respect to repayment of capital or payment of dividends, provided that the Corporation may without such approval issue additional series of Preferred Shares if all dividends then payable on the Series 4 Preferred Shares shall have been paid or set apart for payment.

Voting Rights

The holders of the Series 4 Preferred Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Preferred Shares of any series are in arrears to the extent of eight quarterly dividends or four half-yearly dividends, as the case may be, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series 4 Preferred Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series 4 Preferred Share held.

Tax Election

The Series 4 Preferred Shares will be "taxable preferred shares" as defined in the Tax Act for purposes of the tax under Part IV.1 of the Tax Act applicable to certain corporate holders of the Series 4 Preferred Shares. The terms of the Series 4 Preferred Shares require the Corporation to make the necessary election under Part VI.1 of the Tax Act so that such corporate holders will not be subject to the tax under Part IV.1 of the Tax Act on dividends received (or deemed to be received) on the Series 4 Preferred Shares. See "Certain Canadian Federal Income Tax Considerations - Dividends".

Modification

The series provisions attaching to the Series 4 Preferred Shares may be amended with the written approval of all the holders of the Series 4 Preferred Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for that purpose and at which a quorum is present.

Business Day

If any day on which any dividend on the Series 4 Preferred Shares is payable by the Corporation or on or by which any other action is required to be taken by the Corporation is not a business day, then such dividend shall be payable and such other action may be taken on or by the next succeeding day that is a business day.

Certain Provisions of the Series 5 Preferred Shares

Issue Price

The Series 5 Preferred Shares will be issuable only upon conversion of Series 4 Preferred Shares and will have an ascribed issue price of $25.00 per share.

Dividends on Series 5 Preferred Shares

During each Quarterly Floating Rate Period, the holders of the Series 5 Preferred Shares shall be entitled to receive and the Corporation shall pay, as and when declared by the board of directors, out of the moneys of the Corporation properly applicable to the payment of dividends, cumulative preferential cash dividends, payable on each Dividend Payment Date, in the amount per share determined by multiplying the Floating Quarterly Dividend Rate for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365.

On each Floating Rate Calculation Date, the Corporation shall determine the Floating Quarterly Dividend Rate for the ensuing Quarterly Floating Rate Period. Each such determination shall, in the absence of manifest error, be final and binding upon the Corporation and upon all holders of Series 5 Preferred Shares. The Corporation shall, on each Floating Rate Calculation Date, give written notice of the Floating Quarterly Dividend Rate for the ensuing Quarterly Floating Rate Period to the registered holders of the then outstanding Series 5 Preferred Shares.

Redemption of Series 5 Preferred Shares

The Series 5 Preferred Shares shall not be redeemable prior to June 1, 2021. Subject to the provisions described under "Restrictions on Payments and Reductions of Capital", the Corporation may redeem all or any part of the Series 5 Preferred Shares by the payment of an amount in cash for each share to be redeemed equal to

(a) $25.00 in the case of a redemption on a Series 5 Conversion Date or

(b) $25.50 in the case of a redemption on any other date

plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption.

Notice of any redemption of Series 5 Preferred Shares will be given by the Corporation not more than 60 days and not less than 30 days prior to the date fixed for redemption. If less than all of the outstanding Series 5 Preferred Shares are at any time to be redeemed, the shares to be redeemed will be selected pro rata disregarding fractions or in such other manner as the Corporation may determine.

Conversion of Series 5 Preferred Shares into Series 4 Preferred Shares

The Series 5 Preferred Shares shall not be convertible prior to June 1, 2021. Holders of Series 5 Preferred Shares shall have the right to convert on each Series 5 Conversion Date, subject to restrictions on conversion described below and the payment or delivery to the Corporation of evidence of payment of any tax payable, all or any of their Series 5 Preferred Shares into Series 4 Preferred Shares on the basis of one Series 4 Preferred Share for each Series 5 Preferred Share. Notice of a holder's intention to convert Series 5 Preferred Shares must be received by the transfer agent and registrar for the Series 5 Preferred Shares at its principal office in Toronto not earlier than the 30th day prior to, but not later than 5:00 p.m. (Toronto time) on the 15th day preceding, a Series 5 Conversion Date.

The Corporation shall, not more than 60 days and not less than 30 days prior to the applicable Series 5 Conversion Date, give notice to the then registered holders of the Series 5 Preferred Shares of the conversion right. On the 30th day prior to each Series 5 Conversion Date, the Corporation shall give notice to the then registered holders of the Series 5 Preferred Shares of the Annual Fixed Dividend Rate for the Series 4 Preferred Shares for the next succeeding Subsequent Fixed Rate Period and the Floating Quarterly Dividend Rate for the Series 5 Preferred Shares for the next succeeding Quarterly Floating Rate Period.

Holders of Series 5 Preferred Shares shall not be entitled to convert their shares into Series 4 Preferred Shares if the Corporation determines that there would remain outstanding on a Series 5 Conversion Date less than 1,000,000 Series 4 Preferred Shares, after having taken into account all Series 4 Preferred Shares tendered for conversion into Series 5 Preferred Shares and all Series 5 Preferred Shares tendered for conversion into Series 4 Preferred Shares. The Corporation shall give notice thereof to all affected registered holders of the Series 5 Preferred Shares at least seven days prior to the applicable Series 5 Conversion Date. Furthermore, if the Corporation determines that there would remain outstanding on a Series 5 Conversion Date less than 1,000,000 Series 5 Preferred Shares, after having taken into account all Series 4 Preferred Shares tendered for conversion into Series 5 Preferred Shares and all Series 5 Preferred Shares tendered for conversion into Series 4 Preferred Shares, then all of the remaining outstanding Series 5 Preferred Shares shall be converted automatically into Series 4 Preferred Shares on the basis of one Series 4 Preferred Share for each Series 5 Preferred Share on the applicable Series 5 Conversion Date and the Corporation shall give notice thereof to the then registered holders of such remaining Series 5 Preferred Shares at least seven days prior to the Series 5 Conversion Date.

The Corporation reserves the right not to deliver Series 4 Preferred Shares to any person that the Corporation or its transfer agent has reason to believe is a person whose address is in, or that the Corporation or its transfer agent has reason to believe is a resident of, any jurisdiction outside Canada if such delivery would require the Corporation to take any action to comply with the securities laws of such jurisdiction.

If the Corporation gives notice to the holders of the Series 5 Preferred Shares of the redemption of all of the Series 5 Preferred Shares, the right of a holder of Series 5 Preferred Shares to convert such Series 5 Preferred Shares shall terminate and the Corporation shall not be required to give notice to the registered holders of the Series 5 Preferred Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series 5 Preferred Shares.

Purchase for Cancellation

Subject to the provisions described under "Restrictions on Payments and Reductions of Capital", the Corporation may at any time or times purchase for cancellation all or any part of the Series 5 Preferred Shares at the lowest price or prices at which, in the opinion of the board of directors of the Corporation, such shares are obtainable.

Rights on Liquidation

In the event of the liquidation, dissolution or winding-up of the Corporation or any other distribution of assets of the Corporation among its shareholders for the purpose of winding up its affairs, the holders of the Series 5 Preferred Shares shall be entitled to receive $25.00 per Series 5 Preferred Share plus all accrued and unpaid dividends thereon before any amount shall be paid or any property or assets of the Corporation shall be distributed to the holders of the Class A non-voting shares or Class B common shares or to the holders of any other shares ranking junior to the Series 5 Preferred Shares in any respect. After payment to the holders of the Series 5 Preferred Shares of the amount so payable to them, they shall not, as such, be entitled to share in any further distribution of the property or assets of the Corporation.

Restrictions on Payments and Reductions of Capital

So long as any Series 5 Preferred Shares are outstanding, the Corporation shall not

(a) call for redemption, purchase, reduce or otherwise pay off less than all the Series 5 Preferred Shares and all other preferred shares then outstanding ranking prior to or on a parity with the Series 5 Preferred Shares with respect to payment of dividends,

(b) declare, pay or set apart for payment any dividends (other than stock dividends in shares of the Corporation ranking junior to the Series 5 Preferred Shares) on the Class A non-voting shares or Class B common shares or any other shares of the Corporation ranking junior to the Series 5 Preferred Shares with respect to payment of dividends, or

(c) call for redemption, purchase, reduce or otherwise pay off any shares of the Corporation ranking junior to the Series 5 Preferred Shares with respect to repayment of capital or with respect to payment of dividends

unless all dividends up to and including the dividends payable on the last preceding dividend payment dates on the Series 5 Preferred Shares and on all other preferred shares then outstanding ranking prior to or on a parity with the

Series 5 Preferred Shares with respect to payment of dividends shall have been declared and paid or set apart for payment at the date of any such action.

Creation or Issue of Additional Shares

So long as any Series 5 Preferred Shares are outstanding, the Corporation shall not, without the prior approval of the holders of the Series 5 Preferred Shares, create or issue any shares ranking prior to or on a parity with the Series 5 Preferred Shares with respect to repayment of capital or payment of dividends, provided that the Corporation may without such approval issue additional series of Preferred Shares if all dividends then payable on the Series 5 Preferred Shares shall have been paid or set apart for payment.

Voting Rights

The holders of the Series 5 Preferred Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Preferred Shares of any series are in arrears to the extent of eight quarterly dividends or four half-yearly dividends, as the case may be, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series 5 Preferred Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series 5 Preferred Share held.

Tax Election

The Series 5 Preferred Shares will be "taxable preferred shares" as defined in the Tax Act for purposes of the tax under Part IV.1 of the Tax Act applicable to certain corporate holders of the Series 4 Preferred Shares. The terms of the Series 5 Preferred Shares require the Corporation to make the necessary election under Part VI.1 of the Tax Act so that such corporate holders will not be subject to the tax under Part IV.1 of the Tax Act on dividends received (or deemed to be received) on the Series 5 Preferred Shares. See "Certain Canadian Federal Income Tax Considerations - Dividends".

Modification

The series provisions attaching to the Series 5 Preferred Shares may be amended with the written approval of all the holders of the Series 5 Preferred Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for that purpose and at which a quorum is present.

Business Day

If any day on which any dividend on the Series 5 Preferred Shares is payable by the Corporation or on or by which any other action is required to be taken by the Corporation is not a business day, then such dividend shall be payable and such other action may be taken on or by the next succeeding day that is a business day.

DEPOSITORY SERVICES

Except as otherwise provided below, the Series 4 Preferred Shares and the Series 5 Preferred Shares will be issued in "book-entry only" form and must be purchased, transferred, converted or redeemed through participants ("Participants") in the depository service of CDS or its nominee. Each of the Underwriters is a Participant. On the closing of this offering, the Corporation will cause a global certificate or certificates representing the Series 4 Preferred Shares to be delivered to, and registered in the name of, CDS or its nominee. Except as described below, no purchaser of Series 4 Preferred Shares or Series 5 Preferred Shares, as applicable, will be entitled to a certificate or other instrument from the Corporation or CDS evidencing that purchaser's ownership thereof, and no purchaser will be shown on the records maintained by CDS except through a book-entry account of a Participant acting on behalf of such purchaser. The Corporation understands that each purchaser of Series 4 Preferred Shares or Series 5 Preferred Shares, as applicable, will receive a customer confirmation of purchase from the registered dealer from or through which the Series 4 Preferred Shares or Series 5 Preferred Shares, as applicable, are purchased in accordance with the practices and procedures of that registered dealer. The practices of registered dealers may vary, but generally customer confirmations are issued promptly after execution of a customer order. CDS will be responsible for establishing and maintaining book-entry accounts for its Participants having interests in the Series 4 Preferred Shares or Series 5 Preferred Shares, as applicable. Reference in this short form prospectus to a holder of Series 4 Preferred Shares or Series 5 Preferred Shares, as applicable, means, unless the context otherwise requires, the owner of the beneficial interest in the Series 4 Preferred Shares or Series 5 Preferred Shares, as applicable.

If the Corporation determines, or CDS notifies the Corporation in writing, that CDS is no longer willing or able to discharge properly its responsibilities as depository with respect to the Series 4 Preferred Shares or Series 5 Preferred Shares, as applicable, and the Corporation is unable to locate a qualified successor, or if the Corporation at its option elects, or is required by law, to terminate the book-entry system, then Series 4 Preferred Shares or Series 5 Preferred Shares, as applicable, will be issued in fully registered form to the owners of the beneficial interests in such Series 4 Preferred Shares or Series 5 Preferred Shares, as applicable, or their nominees.

EARNINGS COVERAGE RATIO

The Corporation's dividend requirements on all of its preferred shares, after giving effect to the issue of the Series 4 Preferred Shares and adjusted to a before-tax equivalent using an effective income tax rate of 14.8% and 15.4%, amounted to $29.2 million and $26.4 million for the 12 months ended September 30, 2010, and December 31, 2009, respectively. The Corporation's interest requirements, after giving effect to the issuance of $125,000,000 of 4.947% Debentures on November 18, 2010, amounted to $204.3 million and $206.5 million for the 12 months ended September 30, 2010, and December 31, 2009, respectively.

The Corporation's earnings before interest, income taxes and preferred share dividends for the 12 months ended September 30, 2010, and the 12 months ended December 31, 2009, were $541.8 million and $533.9 million, respectively, which was 2.32 times and 2.29 times the Corporation's aggregate dividend and interest requirements.

RATINGS

The Series 4 Preferred Shares of the Corporation are rated Pfd-2 (high) with a stable trend by DBRS Limited ("DBRS") and P-2 (high) with a stable outlook by Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P").

A Pfd-2 rating by DBRS is the second highest of six categories granted by DBRS. Preferred shares rated Pfd-2 are of satisfactory credit quality. Protection of dividends and principal is substantial, but earnings, the balance sheet, and coverage ratios are not as strong as higher rated companies. Each rating category is denoted by the subcategories "high" and "low". The absence of either a "high" or "low" designation indicates the rating is in the "middle" of the category.

A P-2 rating by S&P is the second highest of eight categories S&P uses in its Canadian preferred share rating scale. An obligation rated P-2 exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. A plus (+) or minus (-) sign shows relative standing within a rating category.

A security rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

TRADING PRICE AND VOLUME

The Corporation's 4,600,000 4.60% Cumulative Redeemable Preferred Shares Series 1 and 6,400,000 6.70% Cumulative Redeemable Preferred Shares Series 2 are listed on the TSX. The following table sets out the high and low prices and the volume of shares traded on the TSX (as reported by TSX Historical Data Access) for the 12-month period before the date of this short form prospectus.

Month	Series 1 High ($)	Series 1 Low ($)	Series 1 Trading Volume	Series 2 High ($)	Series 2 Low ($)	Series 2 Trading Volume
2009						
November	20.80	19.50	38,819	28.79	27.60	188,986
December	20.54	19.68	63,115	29.22	28.04	110,684
2010						
January	21.39	19.79	56,459	29.58	28.02	168,975
February	21.39	19.92	42,854	28.75	28.11	226,183
March	20.30	19.50	59,395	28.60	28.15	168,893
April	19.50	18.50	66,111	28.50	27.09	145,389
May	19.33	18.20	33,072	28.00	27.14	123,763
June	20.20	19.13	31,533	27.98	27.26	22,387
July	20.21	19.76	57,707	28.42	27.79	168,264
August	20.49	19.75	13,630	28.56	28.10	130,320
September	20.76	20.36	21,397	28.50	28.12	150,530
October	21.40	20.63	41,815	28.60	28.30	60,199
November (up to November 23)	22.00	21.08	106,994	28.89	27.86	36,565

RISK FACTORS

A prospective purchaser of Series 4 Preferred Shares should carefully consider the following investment considerations before making a decision to purchase Series 4 Preferred Shares, as well as the other information contained in this short form prospectus and the documents incorporated by reference herein, including, in particular, the information described under the heading “Business Risks” in the Corporation’s management’s discussion and analysis for the year ended December 31, 2009.

Prevailing yields on similar securities will affect the market values of the Series 4 Preferred Shares and the Series 5 Preferred Shares. Assuming all other factors remain unchanged, the market values of the Series 4 Preferred Shares and the Series 5 Preferred Shares will decline as prevailing yields for similar securities rise, and will increase as prevailing yields for similar securities decline. Real or anticipated changes in credit ratings on the Series 4 Preferred Shares or the Series 5 Preferred Shares may affect the market value of the Series 4 Preferred Shares and the Series 5 Preferred Shares.

The Series 4 Preferred Shares and the Series 5 Preferred Shares are equity capital of the Corporation which rank equally with other Preferred Shares of the Corporation in the event of an insolvency or winding-up of the Corporation. If the Corporation becomes insolvent or is wound up, the Corporation’s assets must be used to pay liabilities and other debt before payments may be made on the Series 4 Preferred Shares, the Series 5 Preferred Shares and other Preferred Shares.

An investment in the Series 4 Preferred Shares may become an investment in Series 5 Preferred Shares without the consent of the holder in the event of an automatic conversion of the Series 4 Preferred Shares into Series 5 Preferred Shares. Upon such automatic conversion, the dividend rate on the Series 5 Preferred Shares will be a floating rate that is adjusted quarterly by reference to the T-Bill Rate which may vary from time to time. In addition, holders may be prevented from converting their Series 4 Preferred Shares into Series 5 Preferred Shares in certain circumstances. See “Details of the Offering – Certain Provisions of the Series 4 Preferred Shares”.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Bennett Jones LLP, counsel to the Corporation, and Blake, Cassels & Graydon LLP, counsel to the Underwriters, (collectively "Counsel") the following summary, as of the date hereof, describes the principal Canadian federal income tax considerations generally applicable under the provisions of the Tax Act to a prospective purchaser of Series 4 Preferred Shares pursuant to the Prospectus (a "Holder") who, at all relevant times, for the purposes of the Tax Act, is (or is deemed to be) resident in Canada, holds the Series 4 Preferred Shares or Series 5 Preferred Shares, as applicable, as capital property, and deals at arm's length with the Corporation and is not affiliated with the Corporation. Generally, the Series 4 Preferred Shares or Series 5 Preferred Shares will be considered to be capital property to a Holder provided the Holder does not hold the shares in the course of carrying on a business of trading or dealing in securities and has not acquired them in one or more transactions considered to be an adventure in the nature of trade. Certain Holders who might not otherwise be considered to hold their Series 4 Preferred Shares or Series 5 Preferred Shares as capital property may, in certain circumstances, be entitled to have them treated as capital property by making the irrevocable election permitted by subsection 39(4) of the Tax Act. Holders who do not hold their Series 4 Preferred Shares or Series 5 Preferred Shares, as applicable, as capital property should consult their own tax advisers with respect to their own particular circumstances. This summary assumes that the Series 4 Preferred Shares and the Series 5 Preferred Shares will be listed on a designated stock exchange in Canada under the Tax Act (which currently includes the TSX) at all relevant times.

This summary is not applicable to: (i) a Holder that is a "financial institution", as defined in the Tax Act for the purpose of the "mark-to-market" rules; (ii) a Holder an interest in which would be a "tax shelter investment", as defined in the Tax Act; (iii) a Holder that is a "specified financial institution" or a "restricted financial institution", each as defined in the Tax Act; or (iv) a Holder which has made a "functional currency" election under the Tax Act to determine its Canadian tax results in a currency other than Canadian currency. Any such Holder should consult its own tax advisors with respect to an investment in the Series 4 Preferred Shares or Series 5 Preferred Shares.

This summary is based upon the current provisions of the Tax Act, the regulations thereunder (the "Regulations"), all specific proposals to amend the Tax Act and the Regulations publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the "Proposals"), existing case law and Counsels' understanding of the current written administrative and assessing practices of the Canada Revenue Agency ("CRA"). This summary assumes the Proposals will be enacted in the form proposed, however, no assurance can be given that the Proposals will be enacted in their current form, or at all. This summary is not exhaustive of all possible Canadian federal income tax considerations and, except for the Proposals, does not take into account or anticipate any changes in law, whether by legislative, governmental or judicial decision or action, nor does it take into account any provincial, territorial or foreign income tax legislation or considerations.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular Holder of Series 4 Preferred Shares or Series 5 Preferred Shares. No representations are made with respect to the income tax consequences to any particular Holder. Consequently, prospective Holders should consult their own tax advisers with respect to their particular circumstances for advice with respect to the tax consequences to them of acquiring, holding and disposing of the Series 4 Preferred Shares or the Series 5 Preferred Shares, including the application and effect of the income and other tax laws of any country, province, state or local tax authority.

Dividends

Dividends (including deemed dividends) received (or deemed to be received) on the Series 4 Preferred Shares or the Series 5 Preferred Shares, as the case may be, by an individual (other than certain trusts) will be included in the individual's income and will be subject to the gross-up and dividend tax credit rules normally applicable to taxable dividends received from taxable Canadian corporations. Individuals are entitled to an enhanced gross-up and dividend tax credit in respect of "eligible dividends" received from taxable Canadian corporations, such as the Corporation, if such dividends have been designated as eligible dividends by the Corporation. By notice in writing on the Corporation's website, the Corporation has designated that all taxable dividends paid on its shares on or after January 1, 2006 will be "eligible dividends" within the meaning of the Tax Act unless otherwise stated. Management of the Corporation has advised counsel that the Corporation anticipates that it will designate the dividends paid to holders of the Series 4 Preferred Shares and the Series 5 Preferred Shares as eligible dividends.

Dividends received by a Holder who is an individual (other than certain trusts) may give rise to a liability for alternative minimum tax.

Dividends (including deemed dividends) received on the Series 4 Preferred Shares or the Series 5 Preferred Shares, as the case may be, by a Holder which is a corporation will be included in computing the Holder's income and will generally be deductible in computing the Holder's taxable income. A "private corporation", as defined in the Tax Act, or any other corporation controlled (whether by reason of a beneficial interest in one or more trusts or otherwise) by or for the benefit of an individual (other than a trust) or a related group of individuals (other than trusts), will generally be liable to pay a 33 1/3% refundable tax under Part IV of the Tax Act on dividends received (or deemed to be received) on the Series 4 Preferred Shares or the Series 5 Preferred Shares, as the case may be, to the extent such dividends are deductible in computing its taxable income.

The Series 4 Preferred Shares and the Series 5 Preferred Shares will be "taxable preferred shares" as defined in the Tax Act. The terms of the Series 4 Preferred Shares and the Series 5 Preferred Shares require the Corporation to make the necessary election under Part VI.1 of the Tax Act so that corporate Holders will not be subject to tax under Part IV.1 of the Tax Act on dividends received (or deemed to be received) on the Series 4 Preferred Shares or the Series 5 Preferred Shares.

Dispositions

A Holder who disposes of or is deemed to dispose of Series 4 Preferred Shares or Series 5 Preferred Shares (on the redemption of such shares or otherwise but not including on a conversion) will generally realize a capital gain (or sustain a capital loss) to the extent that the Holder's proceeds of disposition, net of any reasonable costs of disposition, exceed (or are less than) the adjusted cost base of such shares to the Holder. The amount of any deemed dividend arising on the redemption, acquisition or cancellation by the Corporation of Series 4 Preferred Shares or Series 5 Preferred Shares, as the case may be, will generally not be included in computing the Holder's proceeds of disposition for purposes of computing the capital gain (or capital loss) arising on the disposition of such Series 4 Preferred Shares or Series 5 Preferred Shares, as the case may be. See "Redemption" below. If the Holder is a corporation, any capital loss arising on a disposition of a Series 4 Preferred Share or a Series 5 Preferred Share, as the case may be, may, in certain circumstances, be reduced by the amount of any dividends, including deemed dividends, which have been received on the Series 4 Preferred Share or Series 5 Preferred Share or any share which was converted into such share. Analogous rules apply to a partnership or trust of which a corporation, partnership or trust is a member or beneficiary.

Generally, one-half of any capital gain realized in a taxation year will be included in computing the Holder's income in that taxation year as a taxable capital gain and, generally, one-half of any capital loss realized in a taxation year (an "allowable capital loss") must be deducted from the Holder's taxable capital gains realized by the Holder in the same taxation year, in accordance with the rules contained in the Tax Act. Allowable capital losses in excess of taxable capital gains realized by a Holder in a particular taxation year may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net taxable capital gains realized by the Holder in such taxation year, subject to and in accordance with the rules contained in the Tax Act. Capital gains realized by an individual may give rise to a liability for alternative minimum tax. Taxable capital gains of a "Canadian-controlled private corporation", as defined in the Tax Act, may be subject to an additional refundable tax at a rate of 6 2/3%.

Redemption

If the Corporation redeems Series 4 Preferred Shares or the Series 5 Preferred Shares, or otherwise acquires or cancels Series 4 Preferred Shares or the Series 5 Preferred Shares (other than by a purchase by the Corporation of the shares in the open market in the manner in which shares are normally purchased by any member of the public in the open market), the Holder will be deemed to have received a dividend equal to the amount, if any, paid by the Corporation in excess of the paid-up capital (as determined for purposes of the Tax Act) of such shares at such time. Generally, the difference between the amount paid and the amount of the deemed dividend will be treated as proceeds of disposition for purposes of computing the capital gain or capital loss arising on the disposition of such shares. See "Dispositions" above. In the case of a corporate holder, it is possible that in certain circumstances all or part of any such deemed dividend may be treated as proceeds of disposition and not as a dividend.

Conversion

The conversion of the Series 4 Preferred Shares into Series 5 Preferred Shares and the conversion of the Series 5 Preferred Shares into Series 4 Preferred Shares will not constitute a disposition of property for purposes of the Tax Act and, accordingly, will not give rise to a capital gain or capital loss. The cost to a Holder of the Series 5 Preferred Shares or Series 4 Preferred Shares, as the case may be, received on the conversion will, subject to the averaging rules contained in the Tax Act, be deemed to be equal to the Holder's adjusted cost base of the converted Series 4 Preferred Shares or Series 5 Preferred Shares, as the case may be, immediately before the conversion.

PLAN OF DISTRIBUTION

Under an underwriting agreement dated November 16, 2010, between the Corporation and the Underwriters (the "Underwriting Agreement"), the Corporation has agreed to sell and the Underwriters have severally agreed to purchase on December 2, 2010, or on such later date as may be agreed upon, but not later than December 23, 2010, subject to the terms and conditions stated therein, all but not less than all of the Series 4 Preferred Shares at a price of $25.00 per share payable in cash to the Corporation against delivery of such Series 4 Preferred Shares. The obligations of the Underwriters under the Underwriting Agreement may be terminated at their discretion on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. The Underwriters are, however, obligated to take up and pay for all of the Series 4 Preferred Shares if any Series 4 Preferred Shares are purchased under the Underwriting Agreement. The Underwriters have agreed not to offer, sell or deliver any Series 4 Preferred Shares in the United States or to U.S. persons.

The Underwriters may not, throughout the period of distribution, bid for or purchase Series 4 Preferred Shares. The foregoing restriction is subject to certain exceptions, on the condition that the bid or purchase not be engaged in for the purpose of creating actual or apparent active trading in or raising the price of the Series 4 Preferred Shares. These exceptions include a bid or purchase permitted under the Universal Market Integrity Rules administered by the Investment Industry Regulatory Organization of Canada relating to market stabilization and passive market-making activities and a bid or purchase made for and on behalf of a customer where the order was not solicited during the period of distribution. The Corporation has been advised that, in connection with this offering and subject to the foregoing, the Underwriters may overallot or effect transactions which stabilize or maintain the market price of the Series 4 Preferred Shares at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Underwriters are subsidiaries of Canadian chartered banks which have extended credit facilities to the Corporation and certain of its affiliates. Accordingly, under certain circumstances, the Corporation may be considered to be a "connected issuer" of the Underwriters under applicable Canadian securities legislation. The aggregate amount of such credit facilities available to the Corporation and its affiliates is approximately $1.3 billion, of which approximately $106.1 million was drawn as of September 30, 2010. These facilities include non-recourse debt of the Corporation's affiliates for which the lender's recourse in the event of default is limited to the business and assets of the project in question and to the affiliates' equity therein. The Corporation and its affiliates are in compliance with the terms of these credit facilities. At September 30, 2010, the Corporation had available credit facilities of $328.2 million. Of this amount, $300 million is a term facility established in 1999, which was most recently renewed in July 2010. This facility is used as a backstop for the Corporation's commercial paper program and for occasional issues of letters of credit. The remaining $28.2 million are demand operating facilities of the Corporation's subsidiaries. At September 30, 2010, $14.9 million was outstanding under these facilities, and has subsequently increased to $22.8 million. The decision of each Underwriter to participate in this offering was made independently of its bank parent. None of the proceeds of this offering will be applied for the benefit of the Underwriters or any of their related issuers.

The TSX has conditionally approved the listing of the Series 4 Preferred Shares and the Series 5 Preferred Shares. Listing of the Series 4 Preferred Shares is subject to the Corporation fulfilling all of the requirements of the TSX on or before February 14, 2011, including distribution of these securities to a minimum number of public securityholders.

ELIGIBILITY FOR INVESTMENT

In the opinion of Bennett Jones LLP, counsel to the Corporation, and Blake, Cassels & Graydon LLP, counsel to the Underwriters, subject to the provisions of any particular plan and provided they are listed on a designated stock exchange (which includes the TSX), the Series 4 Preferred Shares and the Series 5 Preferred Shares, if issued on the date hereof, generally would be qualified investments under the Tax Act and the Regulations for a trust governed by a registered retirement savings plan, a registered retirement income fund, a registered education savings plan, a registered disability savings plan, a deferred profit sharing plan, or a tax-free savings account (provided that, in the case of a trust governed by a tax-free savings account, the holder thereof does not have a significant interest, within the meaning of the Tax Act, in the Corporation or in any person that does not deal at arm's length, within the meaning of the Tax Act, with the Corporation).

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Series 4 Preferred Shares is CIBC Mellon Trust Company at its principal offices in Toronto and Calgary.

INTEREST OF EXPERTS

Certain legal matters relating to the offering will be passed upon by Bennett Jones LLP for the Corporation and by Blake, Cassels & Graydon LLP for the Underwriters. As at November 23, 2010, partners and associates of Bennett Jones LLP and of Blake, Cassels & Graydon LLP, as a group, beneficially owned, directly or indirectly, less than 1% of any class of securities of the Corporation. R.T. Booth, a partner of Bennett Jones LLP, is a director of Canadian Utilities Limited and of ATCO Ltd., both of which are publicly traded affiliates of the Corporation.

PricewaterhouseCoopers LLP have prepared an independent auditor's report dated February 17, 2010 in respect of the Corporation's consolidated financial statements as at December 31, 2009 and December 31, 2008 and for each of the years in the two year period ended December 31, 2009. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the purchase price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser’s province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser’s province for the particulars of these rights or consult with a legal adviser.

CERTIFICATES

Dated: November 24, 2010

This short form prospectus, together with the documents incorporated by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of each of the provinces of Canada.

"N.C. Southern" (Signed) N.C. SOUTHERN President & Chief Executive Officer	*"B.R. Bale"* (Signed) B.R. BALE Senior Vice President & Chief Financial Officer

On behalf of the Board of Directors

"L.M. Charlton" (Signed) L.M. CHARLTON Director	*"J.W. Simpson"* (Signed) J.W. SIMPSON Director

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of each of the provinces of Canada.

BMO NESBITT BURNS INC.	RBC DOMINION SECURITIES INC.
"Aaron M. Engen" By: (Signed) AARON M. ENGEN	*"David Dal Bello"* By: (Signed) DAVID DAL BELLO

TD SECURITIES INC.

"Alec W.G. Clark"
By: (Signed) ALEC W. G. CLARK

AUDITOR'S CONSENT

We have read the short form prospectus of CU Inc. (the "Corporation") dated November 24, 2010, relating to the issuance of 3,000,000 Cumulative Redeemable Preferred Shares Series 4 of the Corporation. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the use, through incorporation by reference in the above-mentioned prospectus, of our report to the shareholders of the Corporation on the consolidated balance sheets of the Corporation as at December 31, 2009 and 2008 and the consolidated statements of earnings and retained earnings, cash flows, and comprehensive income for each of the years in the two-year period ended December 31, 2009. Our report is dated February 17, 2010.

Calgary, Alberta	*"PricewaterhouseCoopers LLP"* (Signed) PRICEWATERHOUSECOOPERS LLP
November 24, 2010	Chartered Accountants

Attachment 16.4

(Provided in electronic format only due to
document size and in order to conserve paper)

Power & Utilities Research

BMO Capital Markets

The One-Two Punch: Growth Combined With Attractive Yield

April 9, 2012
Toronto, Ontario

Ben Pham, CFA
(416) 359-4061
ben.pham@bmo.com

Industry Rating: **Market Perform**

Initiating Coverage of the Power & Utility Sector

Highlights

- In our view, the investment environment for power & utilities remains attractive. The utilities have spent billions of dollars strengthening the basic infrastructure in Canada over the last 10 years and we expect this to remain the overarching theme for the next several years. In combination with a supportive regulatory regime and attractive regulated ROEs, this produces a potent concoction for a secular EPS growth theme.
- We believe investors will continue to seek dividend-growth stocks. The large-capitalization utilities currently offer an average 3.5% yield, which is ~150 bps higher than the current 10-year Government of Canada bond; over the last 10 years, the large-capitalization utilities averaged a yield of 20 bps lower than the 10-year bond average. Not only are sector dividend yields attractive relative to bond yields but also many of these utilities have consistently grown their dividends over time.
- Price earnings multiples sector-wide continue to be at the high end of the historical range and the group is currently trading at a 56% premium to the TSX Composite Index. We believe a premium valuation is warranted for the utility space over our forecast period given our expectation for continued low interest rates; however, we see little upside remaining to valuation multiples. Incremental outperformance will likely be predicated on selective exposure to companies that offer the best combination of earnings and dividend growth.
- We are initiating coverage with Outperform ratings on Canadian Utilities ($70 target); Capital Power ($26 target); and Fortis ($34.50 target). We maintain a Market Perform rating on the Power & Utility sector.

Company	Ticker	Rating	05-Apr-12	Target Price	Dividend Yield	Total Return	Target Multiple 2013E
Boralex	BLX	Market Perform	$8.00	$9.00	0.0%	12.5%	DCF
Canadian Utilities	CU	Outperform	$66.12	$70.00	2.7%	8.5%	17.0x EPS
Capital Power	CPX	Outperform	$23.40	$26.00	5.4%	16.5%	8.5x EV/EBITDA
Caribbean Utilities[1]	CUP.U	Underperform	$9.95	$9.50	6.6%	2.1%	13.5x EPS
Emera	EMA	Market Perform	$33.75	$34.00	4.0%	4.7%	18.5x EPS
Fortis	FTS	Outperform	$32.11	$34.50	3.7%	11.2%	19.0x EPS
TransAlta	TA	Market Perform	$18.12	$19.00	6.4%	11.3%	8.5x EV/EBITDA

Note: (1) All figures in U.S. dollars
(2) Priced as of market close on April 5, 2012
Source: Company Reports, BMO Capital Markets

This report was prepared by an analyst(s) employed by BMO Nesbitt Burns Inc., and who is (are) not registered as a research analyst(s) under FINRA rules. For disclosure statements, including the Analyst's Certification, please refer to pages 109 to 111.

Table of Contents

Investment Summary

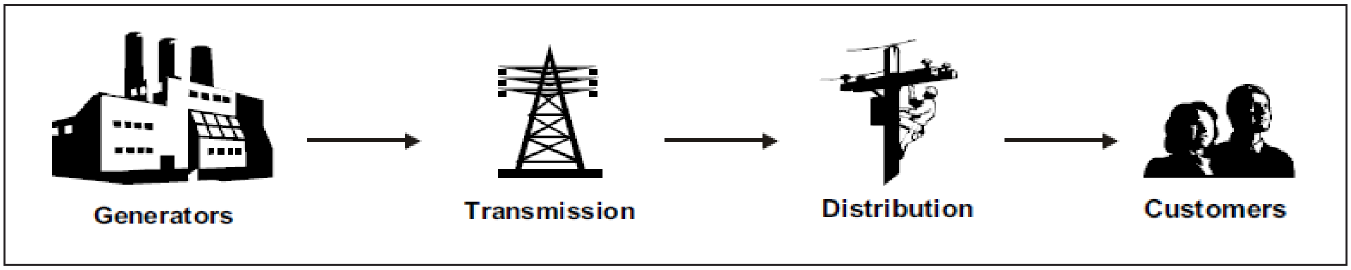
Initiating coverage of the Utility sector. We are initiating coverage of the Canadian Utility sector and seven companies (Table 1), whose operations largely span the electricity value chain (Exhibit 1). We currently prefer stocks with primarily regulated operations while generally avoiding commodity-exposed names. ***Companies with significant regulated operations that we think offer the most upside include Outperform-rated Canadian Utilities (CU, $70 target price) and Fortis Inc. (FTS, $34.50 target price). Among the power producers, we have an Outperform rating for Capital Power (CPX, $26 target price).***

Table 1: *BMO Utility Coverage Universe*

Company	Ticker	Rating	Price	Price Target	Current Yield	Total Return	Shares O/S (mm)	Market Cap (mm)	Earnings Per Share 2011	2012E	2013E	EPS CAGR ('11-'13)	'13E Div. Payout	'13E EV/EBITDA
Boralex	BLX	Market Perform	$8.00	$9.00	0.0%	12.5%	37.7	$302.6	($0.07)	($0.07)	($0.29)	nmf	0.0%	14.5
Canadian Utilities	CU	Outperform	$66.12	$70.00	2.7%	8.5%	127.6	$8,402.3	$3.63	$4.03	$4.13	6.5%	45.2%	10.0
Capital Power	CPX	Outperform	$23.40	$26.00	5.4%	16.5%	97.2	$2,283.8	$1.24	$1.44	$1.64	14.9%	76.8%	8.4
Caribbean Utilities Co. Ltd. [1]	CUP.U	Underperform	$9.95	$9.50	6.6%	2.1%	28.6	$286.3	$0.67	$0.67	$0.70	2.0%	94.9%	10.6
Emera	EMA	Market Perform	$33.75	$34.00	4.0%	4.7%	122.2	$4,175.5	$1.65	$1.72	$1.84	5.7%	76.2%	13.2
Fortis	FTS	Outperform	$32.11	$34.50	3.7%	11.2%	188.8	$6,133.7	$1.66	$1.74	$1.81	4.4%	67.7%	10.6
TransAlta	TA	Market Perform	$18.12	$19.00	6.4%	11.3%	224.6	$4,186.8	$1.04	$1.12	$1.15	5.3%	101.0%	8.0
Average					**4.1%**	**9.5%**						**6.5%**	**66.0%**	**10.8**

Note: (1) All figures in US Dollars
(2) Priced as of market close on April 5, 2012
Source: Company Reports, BMO Capital Markets

Exhibit 1: *Electricity Value Chain*

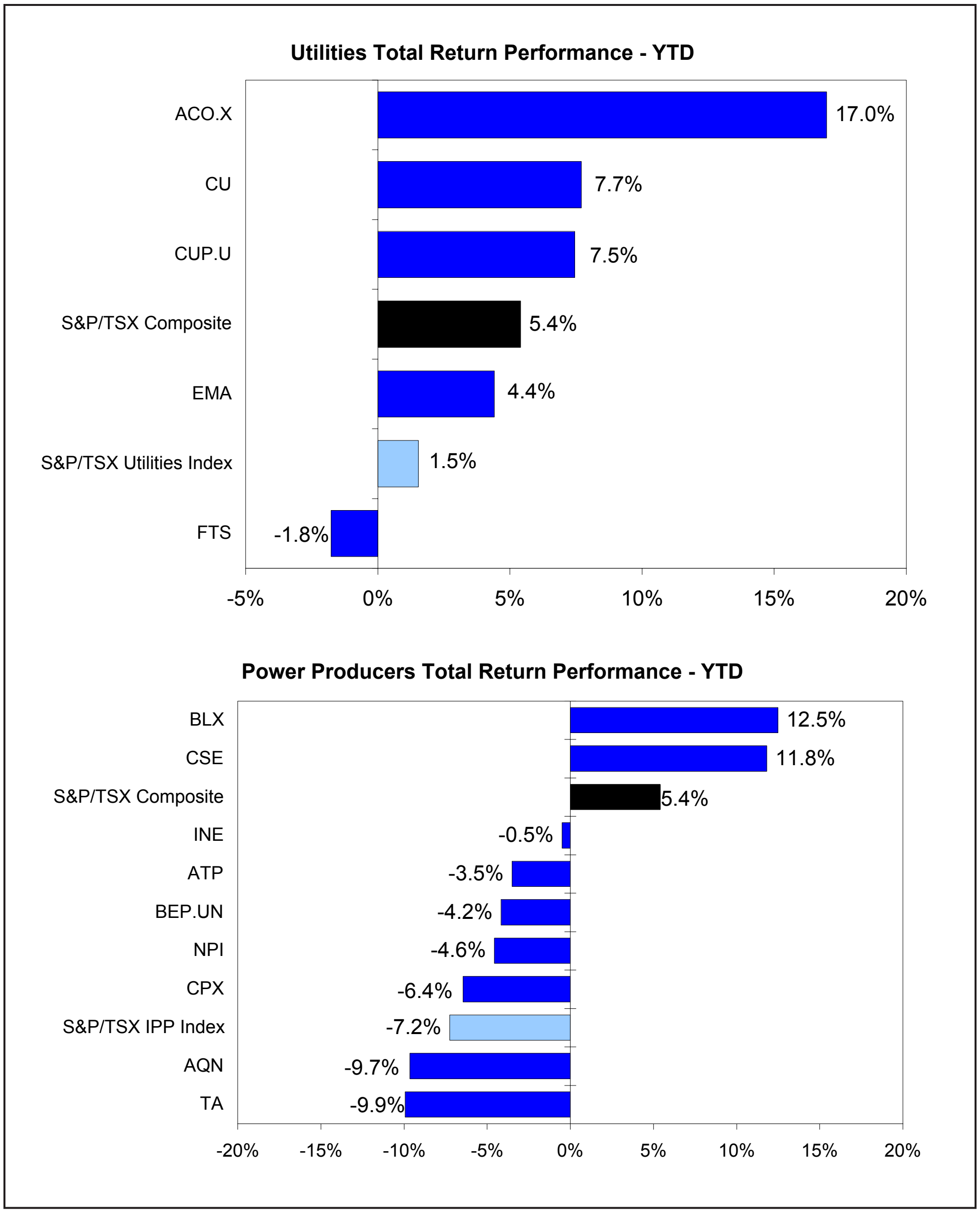


Source: Company Reports

The attraction of the regulated utilities has been appreciated by the market so far this year. In part, continued low bond yields are behind much of the stock price movement, but so have higher earnings visibility and above-average growth. Conversely, many of the power producers are currently in the red on a total return basis. Year-to-date 2012, share prices among entities in the power and utility universe have varied by roughly 27%.

We expect a two-year earnings CAGR of 5.7% for the large-capitalization utilities. For the large-capitalization utilities (CU, FTS, EMA), our outlook is dominated by large capital spending programs that should support two-year earnings CAGR of 5.7% through 2013. We expect dividend growth for the group at 5.0% per annum over the same time period.

Exhibit 2: *Utilities Have Outperformed Power Producers YTD (YTD April 2, 2012)*



Source: Bloomberg

In our view, the major challenge is whether provincial regulators will continue to allow for an increase in revenue requirements following several years of rate hikes. On the one hand, the need for massive infrastructure upgrades in Canada will likely be a politically charged process, with politicians urging for a need to replace out-of-date and failing infrastructure, reduce the grid's reliance on coal and lower the need for expensive imports. On the other hand, electricity consumption growth is not yet keeping up with rate base growth, so the last several years of rate hikes have begun to take a greater share out of consumer wallets. As regulators may become increasingly sensitive to the financial burdens of the consumer/ratepayer, they could start putting the brakes on future rate increases, and thus lower our earnings growth expectations for the sector.

We have a more positive bias toward names with minimal commodity exposure:

- **The large-capitalization utilities generate less volatile earnings.** The large-capitalization utilities are backed by long-life, fundamentally sound assets, with regulatory mechanisms allowing full recovery of prudently incurred capital and operating costs. We believe utilities with minimal exposure to commodity prices should trade at a premium valuation on the perception that earnings are more predictable and that earnings risk is lower.

***Table 2:** Split of Operations*

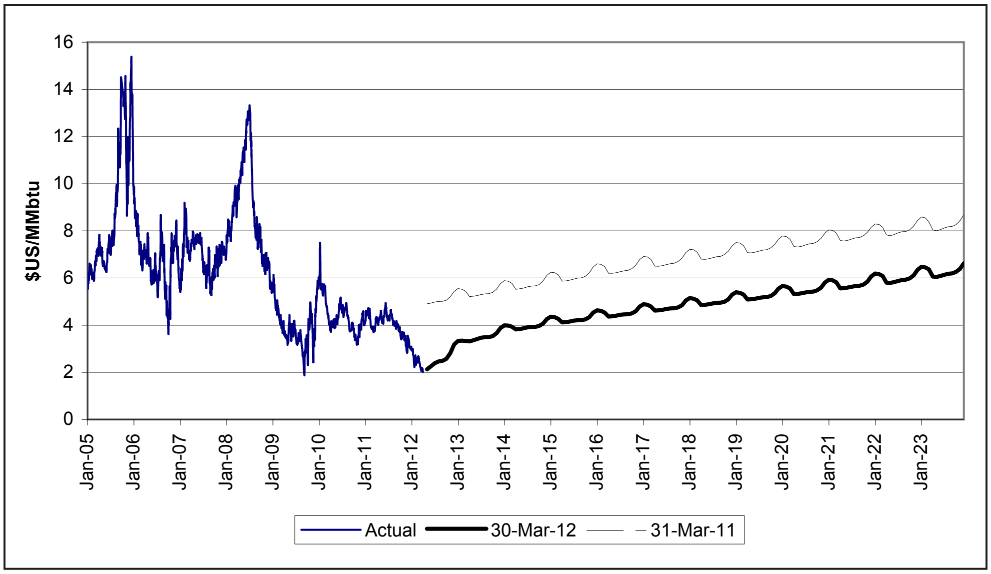
	Regulated		Power		
	Utility	Pipeline	Contracted (1)	Merchant	Midstream/ Trading
Boralex (4)	0.0%	0.0%	93.3%	6.7%	0.0%
Canadian Utilities (2)	66.0%	0.0%	16.0%	7.5%	10.5%
Capital Power (4)	0.0%	0.0%	39.8%	58.9%	1.3%
Caribbean Utilities (2)	100.0%	0.0%	0.0%	0.0%	0.0%
Emera (2)	84.1%	11.6%	3.0%	0.0%	1.3%
Fortis (2)	90.0%	0.0%	5.0%	0.0%	5.0%
TransAlta (3)	0.0%	0.0%	54.1%	43.0%	2.9%

Notes:
1 Does not include financial hedges
2 Expressed as a percentage of 2013E earnings
3 Expressed as a % of 2013E revenues
4 Expressed as a % of 2013E EBITDA
Source: Company Reports, BMO Capital Markets

- **Alberta power markets expected to remain strong, but relatively soft elsewhere.** Our BMO Capital Markets Energy Team forecasts Henry Hub natural gas prices to be US$2.76/Mcf during 2012 and increase to US$3.50/Mcf in 2013. With natural gas prices expected to remain low over our forecast period, this makes it less likely for power prices to swing higher. The one exception is in Alberta, where power prices have decoupled from natural gas and have been relatively strong due to robust demand fundamentals (i.e., oil sands). CPX should realize the greatest benefit from strength in the Alberta power market, but relatively weak NEPOOL electricity prices will likely cause spark spread compression for its New England-based facilities. Similarly, TA has significant exposure to Alberta, but it also has a sizable capacity position in the Pacific Northwest market with its Centralia coal-fired facility. The forward curve in Alberta is currently at $67.50 per MWh for 2013. Conversely, Pacific Northwest 2013 forward prices are ~US$31 per MWh and NEPOOL forward prices are ~US$45 per MWh. As set out in Exhibit 3, the forward curve for natural gas has declined 25–55% since last year.

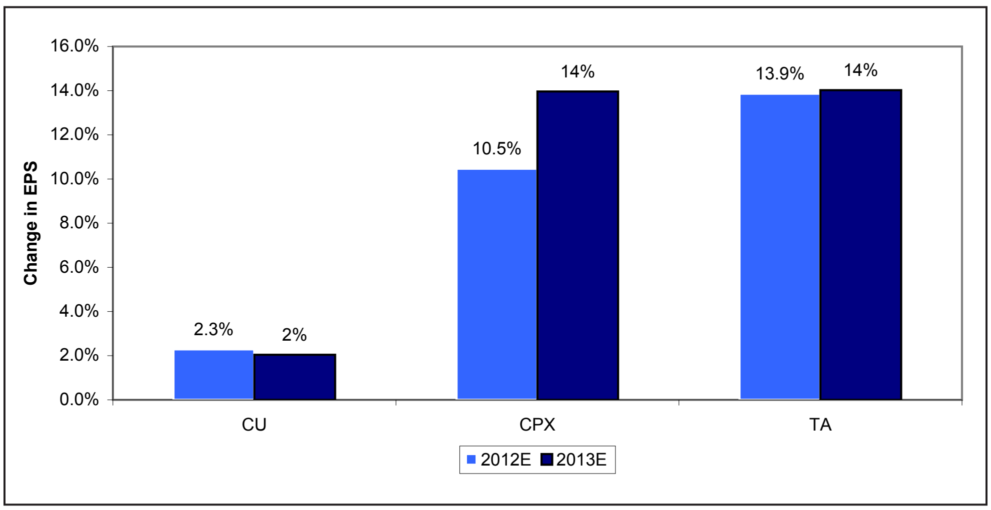
- **There is uncertainty regarding final regulations on emissions from coal-fired power.** In recent years, there has been heighted environmental risk for the Canadian power industry due to global efforts to reduce carbon and other air emissions. In our view, there is minimal financial impact on the regulated utilities, as they should be able to recover through rates the ultimate cost of any mandated environmental compliance standards. For the power industry, these regulations are not a concern for entities owning renewable power facilities, but they could have significant implications for entities that own coal-fired facilities, such as CPX and TA. On August 19, 2011, the Government of Canada issued a press release disclosing that it had completed draft regulations designed to

***Exhibit 3:** Natural Gas Forward Curve Has Declined Significantly Since Last Year*



Source: SNL Financial

***Exhibit 4:** CPX and TA Are The Most Sensitive to Alberta Power Prices ($5/ MW Delta)*



Source: Company Reports, BMO Capital Markets

reduce the emissions released from coal-fired power generation facilities. Pursuant to these draft regulations, the federal government would require all Canadian coal-fired power plants to be decommissioned by the latter of the end of their useful lives (defined as 45 years of age) or at the conclusion of any power purchase arrangement presently in effect. However, it is possible that the Government of Canada may be considering a more flexible approach to regulating coal-fired power generation in that, under certain conditions, the federal government may allow individual provinces to regulate coal emissions as long as the net effect of provincial regulations match those issued by the federal government. We expect the Government of Canada to issue final regulations in the summer of 2012.

Our Outperform Recommendations

Fortis Inc. (Outperform; $34.50 target) – The All-Weather Stock

We are initiating coverage of Fortis Inc. with an Outperform rating and a $34.50 target price (representing a target P/E of 19x). Fortis is hardly a market darling these days amid less robust earnings growth and uncertainty regarding its unregulated hydro assets in Belize. We have heard this song before, and while we recognize the market is waiting anxiously for a full resolution of these issues, we would argue that these issues are already priced in. In the meantime, we believe the market should return its attention to the company's sizable $5.5 billion relatively low-risk organic growth initiatives through 2016, which should ultimately bear fruit.

Aside from its organic growth execution scorecard, we believe another key driver for Fortis' share price in the near term is the successful consummation of New York-based utility CH Energy, which still requires approval from CH Energy shareholders (likely summer 2012) and regulators (Q1/13). We currently assume a $500 million common equity issue at the beginning of 2013 to permanently finance the transaction, with estimated accretion of $0.03 per share. We think patient equity investors may find the current share price attractive and we recommend accumulating shares.

Canadian Utilities (Outperform; $70 target) – Utility Business to Drive Growth

We are initiating coverage of Canadian Utilities with an Outperform rating and a target price of $70 (representing a target P/E of 17x). Despite the fact that Canadian Utilities Limited is currently a diversified energy utility with operations not only in regulated utilities but also in midstream and power, the rubber hits the road when it comes to its utility business, particularly in electric transmission infrastructure, where investment growth is expected to be ~35%. Also, the company's annual dividend of $1.77 translates to a yield of 2.7% and a payout ratio of only ~44%, providing lots of room for dividend upside. Although it has one of the highest investment growth rates among our coverage universe, Canadian Utilities is still trading at a relatively attractive valuation in our view (16.0x 2013E earnings), where we see the potential for multiple expansion given improved financial transparency and an improvement in earnings quality and visibility (utility operations are expected to increase to ~66% of earnings in 2013 vs. ~54% in 2011, with the possibility of ~77% regulated utility exposure by 2015). We recommend accumulating shares at these levels.

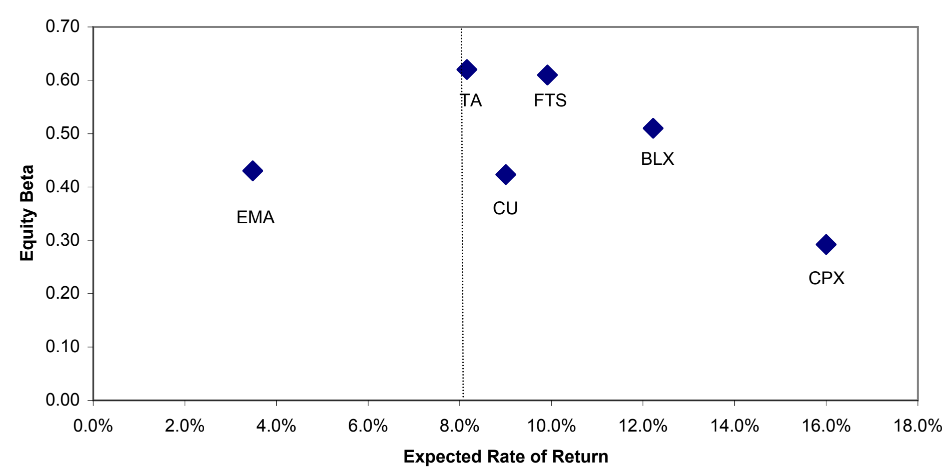
Capital Power (Outperform; $26 target) – The Future Looks Bright

We are initiating coverage of Capital Power with an Outperform rating and a $26 target price (representing a target EV/EBITDA of 8.5x). As a growth-oriented power producer, we believe Capital Power's recent relative valuation compression reflects a multitude of market concerns ranging from uncertainty regarding the direction of Alberta power prices to the large equity overhang. While these are legitimate considerations, we believe Capital Power's solid operating performance has largely gone unnoticed. Fleet availability has averaged 93% over the last four years, in part a reflection of its young fleet (average age of ~12 years) and management's sharp focus on operational excellence. In our view, the path to a higher relative valuation for Capital Power revolves around continued strong operating metrics and EPCOR Utilities' divestment of its remaining ~29% interest in Capital Power. Not to be overlooked is the fact that with the sale of its interest in Capital Power Income in the rear-view mirror, CPX is structurally cleaner and more strategically focused, in our view. In terms of Capital Power's potential catalysts, the following are key: (1) sanctioning K2 wind and the Port Dover/Nanticoke projects; (2) bringing Halkirk and Quality Wind on-stream in the fourth-quarter; (3) the possibility of a dividend bump; and (4) posting respectable production and operating metrics. Longer term, CPX should benefit from the evolution of the environmental regulation landscape. We recommend accumulating shares at these levels.

Investment Drivers for the Industry Are Positive

- **Global macroeconomic concerns remain.** While recent global economic data have started to ease some of the market's concerns, global growth will likely remain weak for 2012 and into 2013. From history, we know that defensive investments strengthen during recessions, especially for the regulated names. Indeed, the Utilities lived up to their defensive nature last year, with the S&P/TSX Utilities Index posting a 6.5% total return versus a -8.7% total return for the TSX Composite.
- **Income and capital preservation.** We believe utility stocks are an attractive defensive investment vehicle for investors for income generation and capital preservation in the current volatile market environment. In Exhibit 5, we provide a company-specific risk/reward matrix for our coverage universe. In our minds, the current investment climate has the potential to reward investors who are paying attention to companies exhibiting an 8%+ total return profile, particularly those in the bottom right quadrant of this analysis, where risk/reward is generally most attractive. CPX shows attractive expected return and volatility combinations.

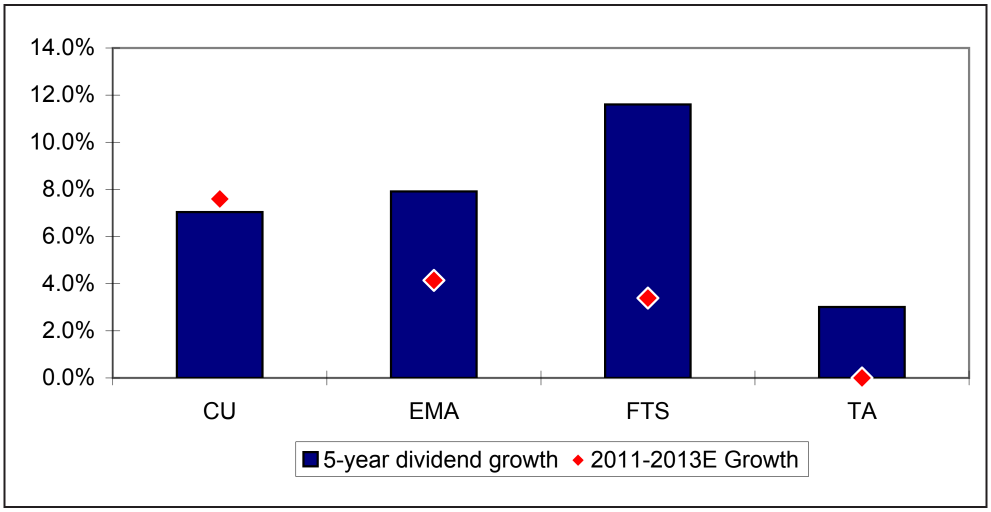
***Exhibit 5:** BMO's Coverage – Equity Beta vs. 1-year ROR*



Note: Equity Beta is for last two years relative to the S&P/TSX Composite
Source: Bloomberg, BMO Capital Markets

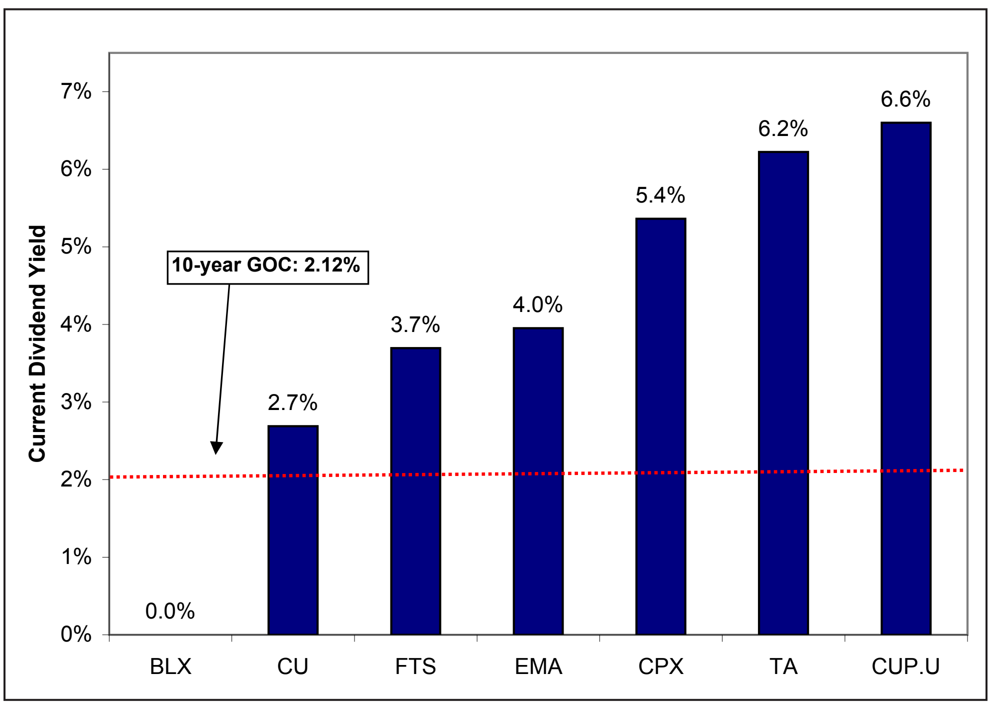
The large-capitalization utilities (CU, EMA, FTS) currently offer an average 3.5% yield, which is ~150 bps higher than the current 10-year Government of Canada bond; over the last 10 years, the large-capitalization utilities averaged a yield of 20 bps lower than the 10-year bond average of 401 bps. Not only are sector dividend yields attractive relative to bond yields, given the current pickup, many of the utilities have consistently grown their dividend over time.

Exhibit 6: *Dividend Growth Rate*



Note: BLX does not pay a dividend; we do not expect dividend increases for CUP.U and CPX over our forecast period
Source: BMO Capital Markets

Exhibit 7: *Dividend Yield*

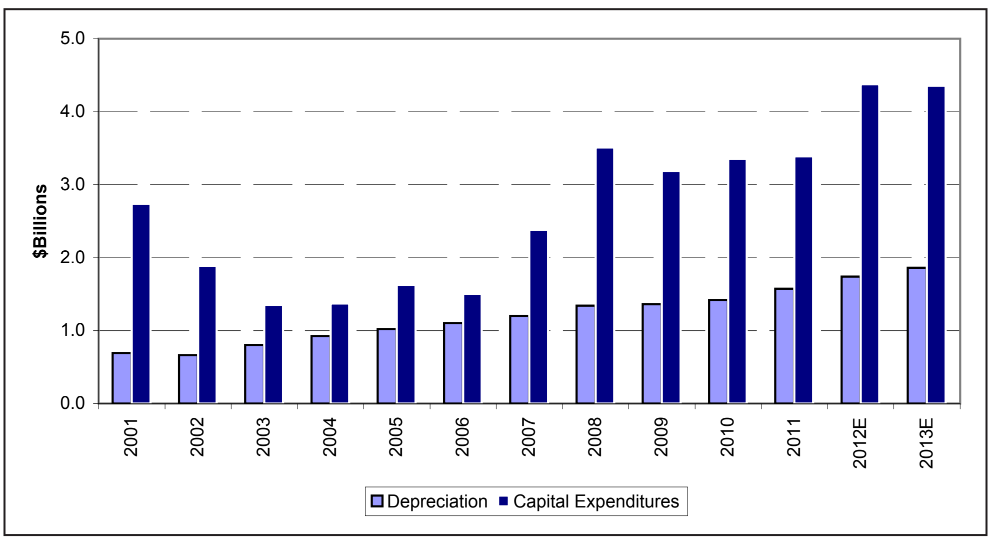


Source: BMO Capital Markets

- **We expect interest rates to remain accommodating.** Although the correlation between the 10-year Government of Canada bond yield and utility dividend yields has been relatively weak since the mid-2000s, we still believe utilities will maintain their role as an income-oriented security, despite other drivers such as higher-than-average rate base growth or higher earnings transparency, which could have weakened the correlation over time. We believe equity investors will continue to seek dividend-growth stocks. Therefore, we believe that if government bond yields remain low for an extended period of time, there could be upside to valuation multiples.

- **Visibly large infrastructure requirements.** Although dividend growth is the main catalyst for common share prices today, rate base growth should also boost prices. The utilities have been focusing on strengthening the basic infrastructure in Canada and we expect this to remain the overarching theme for the next several years. For our coverage universe, capital spending has increased steadily over the last 10 years. As long as capex is growing faster than depreciation, utility earnings should continue to grow. As illustrated in Exhibit 8, capital spending has surpassed depreciation for the last 10 years, and has been significantly higher since 2007. We expect this trend to continue until at least the middle of this decade. Drivers for higher capital budgets include: (i) electric transmission expansion/upgrades; (ii) the replacement of coal plants with natural gas-fired and renewable power facilities; and (iii) upgrading the distribution network (including smart meters and conservation measures).

Exhibit 8: *Aggregate Capital Spending for Coverage Universe*



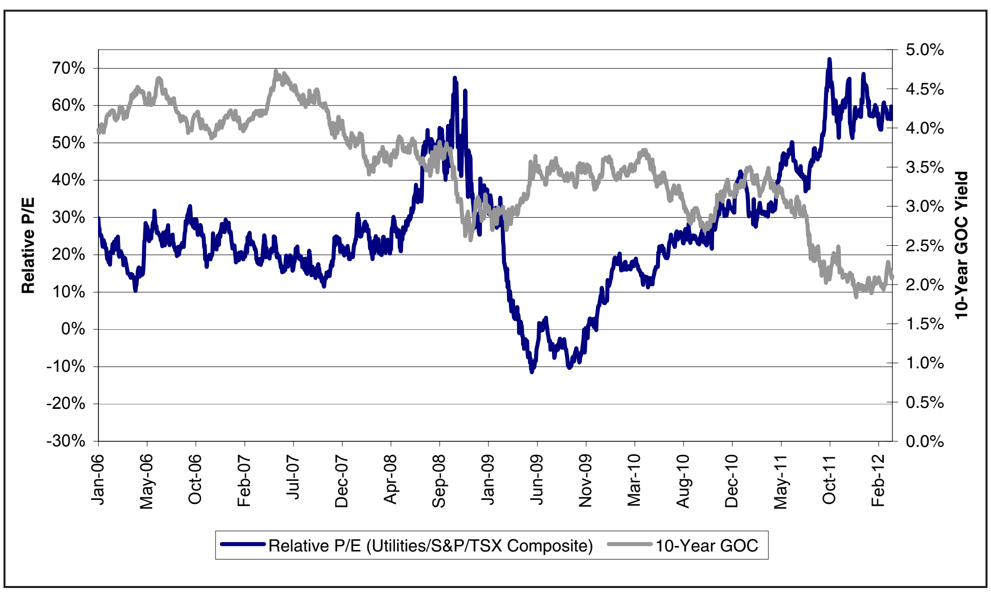
Note: Does not include CUP.U and CPX
Source: BMO Capital Markets, Company Reports

- **The regulatory environment is constructive.** In general, Canadian regulators remain supportive of capital spending plans necessary to improve grid reliability. However, we expect some deterioration in the 2012 allowed ROE, largely in the 15–20 bps range
- **Other positive sector attributes include:** (i) cyclically resilient cash flows given the essential nature of the services provided; (ii) virtually all domestic exposure; and (iii) a monopoly-based market structure providing economies of scale and greater visibility on long-term earnings generally.

Industry Caveats and Investment Risks

- **The most significant risk to the sector is an increase in government bond yields.** Price earnings multiples sector-wide continue to be at the high end of the historical range and the group is currently trading at a premium to the TSX Composite Index. We see value in the utility space on a total return basis, but they generally do not offer a compelling deep value investment opportunity currently. From 2006 to mid-2008, the group traded in the range of a 10–30% premium to the market. Since the financial crisis began in late 2008, the sector has traded at a 70% premium to a discount of 10%. Today the sector is trading at a 56% premium on forward estimates, which is at the high end of the historical range. We believe a premium valuation is warranted for the utility space over our forecast period given our expectation for continued low interest rates. However, should investors wish to invest in the Utility common shares in our coverage universe or to expand positions to establish a defensive portfolio, they will be doing so at historically high valuation levels and we see limited upside remaining to valuation multiples. Incremental outperformance will be predicated on selective exposure to utilities that offer the best combination of earnings and dividend growth.

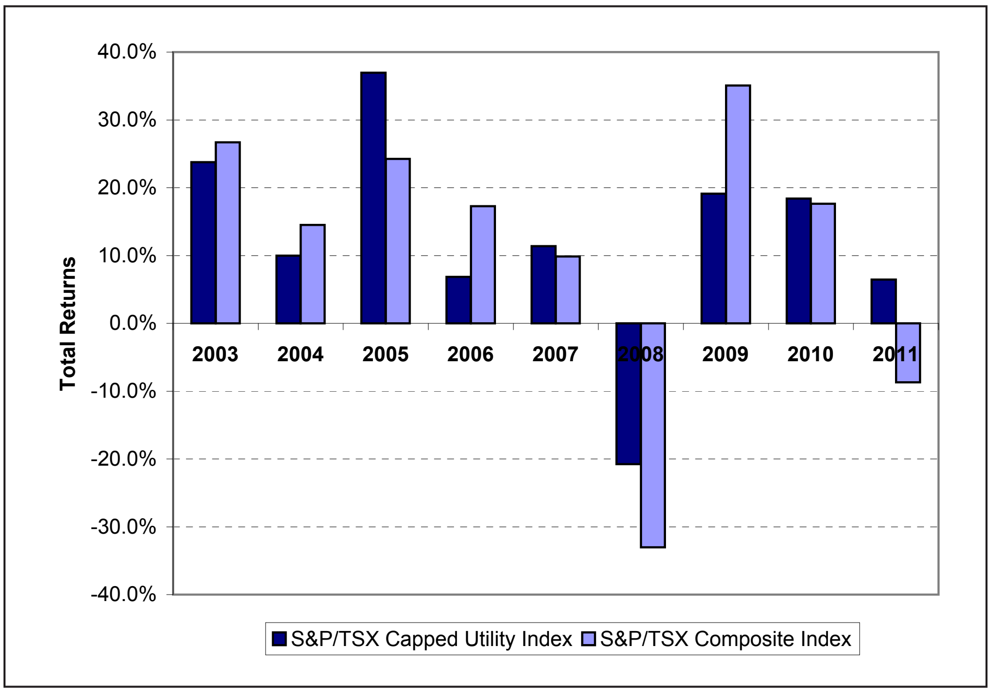
Exhibit 9: *Utility Sector P/E Relative to the Market*



Source: Bloomberg

- **Recent outperformance of defensive over cyclical could hurt the utility sector.** A rotation into defensive stock investments has been taking place since 2010, following a rally in cyclical stocks during 2009. Last year, the S&P/TSX Utilities Index posted a 6.5% total return, comfortably beating the TSX Composite Index, which ended down for the year with a -8.7% total return. In our view, some of the reasons for the outperformance, such as heightened global macroeconomic risks and record low interest rates, could be somewhat temporary. A clear resolution to the European crisis and sustained improvement in global leading and confidence indicators should continue to fuel the recent powerful rally in cyclical equity investments. However, if economic indicators point to a more systemic weakness in the recovery of the global economy, defensive names should continue to beat the market. Since 2003, the utility sector has outperformed the market five of the nine times, as illustrated in Exhibit 10.

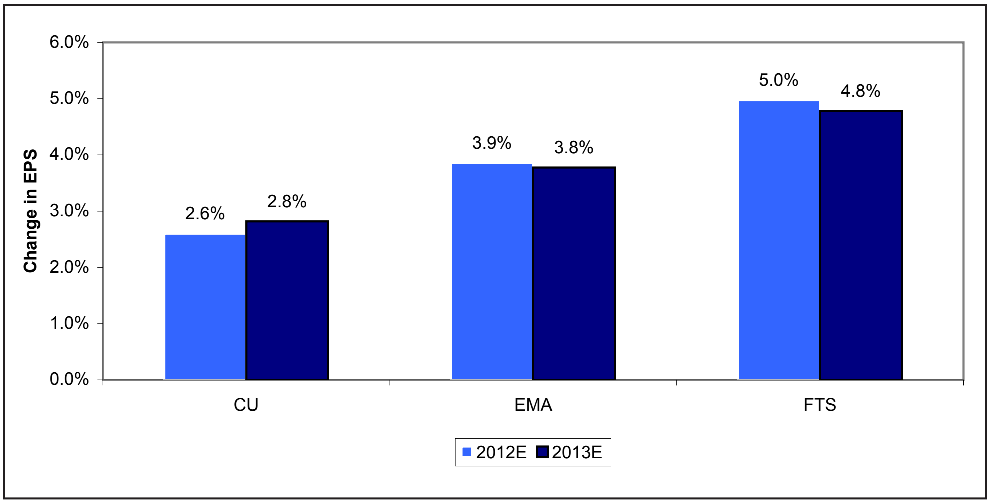
Exhibit 10: *Utility Sector Performance (2003–2011)*



Source: Bloomberg

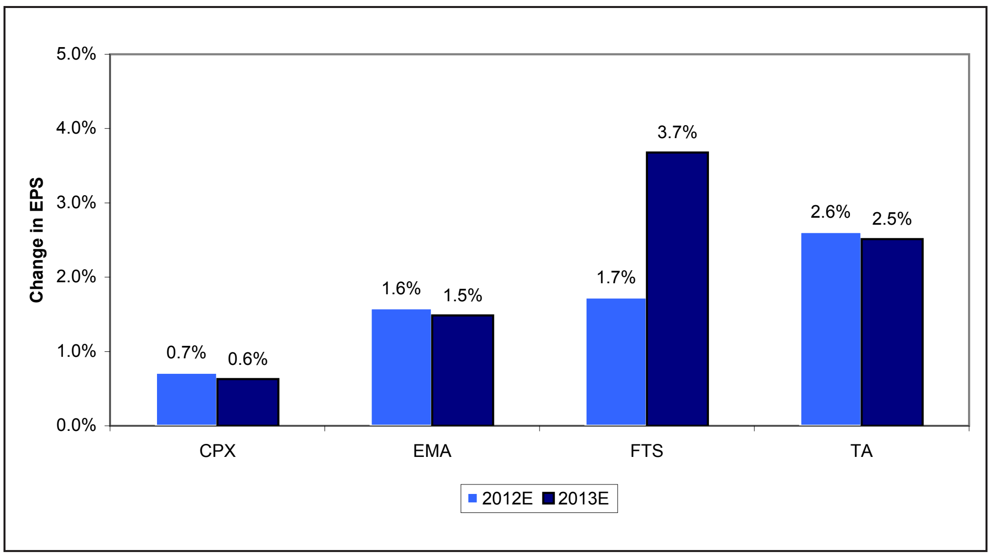
- **The recent significant decline in 10-year bond yields may lead to pressure on Canadian regulated ROEs.** Regulated returns experienced a systematic decline during most of the last decade and were a focus for investors as a primary earnings headwind, but during 2009 many provincial regulators held cost of capital hearings that resulted in higher allowed returns and equity thicknesses. In our view, the regulatory changes are so far working in favour of equity investors through improved earnings, but uncertainty still lingers over how regulators will establish allowed utility returns in the future, especially given that 10-year bond yields have compressed by close to 100 bps since the beginning of 2011. Recently, the Alberta Utilities Commission lowered the ROE to 8.75% from 9.00%. The British Columbia Utilities Commission has initiated a cost of capital hearing, which could result in a reduction to the 2013 B.C. ROE given that it is currently above 9.5%, one of the highest in Canada.

Exhibit 11: *FTS' EPS is the most sensitive to 50 bps change in allowed ROE*



Source: Company Reports, BMO Capital Markets

Exhibit 12: *TA and FTS EPS are the most sensitive to 10% strengthening of USD*



Source: Company Reports, BMO Capital Markets

Investment Drivers for the Power Space

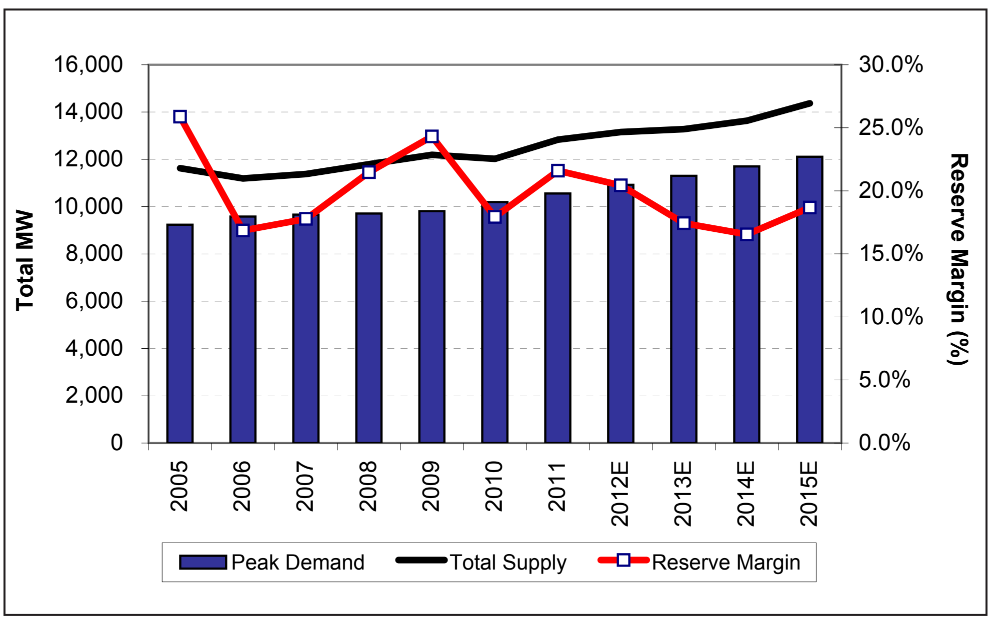
In our view, there are three key considerations when assessing the power space: supply and demand fundamentals, the price of natural gas and the cost of building new generation. Canada's power generation companies (CPX, TA) have diversified into U.S. markets in recent years, but the bulk of their earnings still reside in Alberta. As a result, our analysis focuses mainly on Alberta.

We Expect Alberta Reserve Margins to Tighten in 2013/2014

In any industry, if demand keeps up with supply on a sustainable basis, then the industry should remain profitable. The same is true for the power industry. We assess how tight the power markets are by looking at the reserve margin, which is total available firm generation supply relative to peak demand, expressed as a percentage. Power markets get tighter as the reserve margins decrease, which in turn typically leads to higher power prices.

Alberta electricity consumption has grown at a CAGR of 3.2% over the last decade. Going forward, we assume demand growth of 3.5% per annum through 2015, reflecting increased demand in major urban centres such as Calgary and Edmonton, and oil sands demand growth in northeastern Alberta. For this analysis, we include only projects that currently are under construction or have received regulatory approval and omit those that we think will not move forward. Wind is included at a capacity value of 20%, as wind power may not be fully available at the time of system peak. Also, we have trimmed hydro capacity by one-third to reflect limited storage capabilities and the inability to operate at full output during winter as peak load occurs. While demand and supply look to be relatively balanced during 2012, the trend suggests tightening in 2013–2014, before softening in 2015 due largely to the addition of ENMAX's 800 MW Shepard natural gas-fired facility.

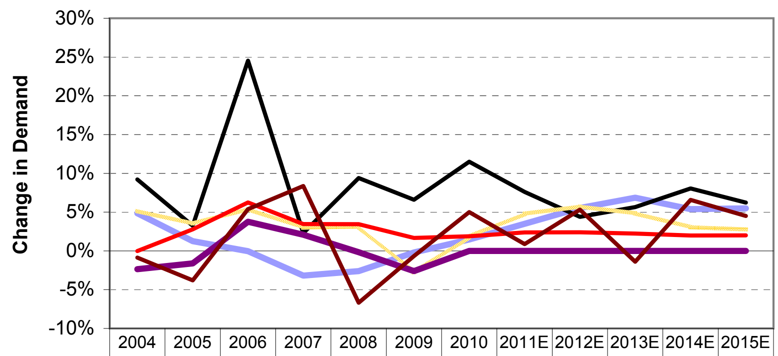
***Exhibit 13:** Alberta – Estimated Reserve Margins*



Note: Assumes 3.5% demand growth
Source: AESO, Alberta Government, BMO Capital Markets

As illustrated in Exhibit 14, demand fundamentals are exhibiting bullish signals. The future growth pattern shows robust demand in oil sands activity, above-average load in the industrial and commercial market, and stabilization of demand from residential customers. For the last couple of years, there has been virtually no growth in industrial consumption, but oil sands demand has continued to grow at an above-average clip.

Exhibit 14: *Alberta Demand Growth (2004–2015E)*



	2004	2005	2006	2007	2008	2009	2010	2011E	2012E	2013E	2014E	2015E
Industrial without Oil Sands	5%	1%	0%	-3%	-3%	0%	1%	3%	6%	7%	5%	5%
Oil Sands	9%	3%	25%	2%	9%	7%	11%	8%	4%	6%	8%	6%
Commercial	5%	4%	5%	3%	3%	-3%	2%	5%	6%	5%	3%	3%
Residential	0%	3%	6%	3%	3%	2%	2%	2%	2%	2%	2%	2%
Farm	-2%	-2%	4%	2%	0%	-3%	0%	0%	0%	0%	0%	0%
Other	-1%	-4%	5%	8%	-7%	-1%	5%	1%	5%	-1%	7%	5%

Note: Other includes transmission losses and supply to Fort Nelson
Source: 2011 AESO Long-term Transmission Plan

We Estimate a Long-Term Power Price of ~$65/MWh in Alberta Based on New Build Economics

The other driver, after demand and supply, is the economic supply costs for new generation. In Alberta, wholesale power prices have tended to be driven by natural gas prices about half the time. This is because natural gas is often the marginal fuel, meaning it is typically the fuel that is used to run the plant that submits the highest price and thus sets the spot electricity price at a certain time. Running base load coal plants in Alberta is relatively cheap, so during peak hours more expensive units are used to meet demand and often these plants are natural gas-fired plants. We think that as coal-fired facilities are phased out of Alberta, natural gas will have a larger influence in setting the power price cost curve.

In Table 3 we estimate the power price that is required to earn a 12% accounting rate of return on a natural gas-fired facility in Alberta over the lifetime of the plant under various natural gas price scenarios. In a sub-$3 natural gas price environment, the power price in Alberta should be closer to $55–60 per MWh based on new-build economics. However, we believe the decision to build a new gas-fired facility by utility executives will depend more on their outlook for natural gas prices on a longer-term basis rather than just today's spot price. *When you take a longer-term view, a reasonable natural gas price assumption is $4, which, based on our math, implies a required power price of roughly $65 per MWh.* We note that this excludes any possible environmental costs that could drive up the required power price further.

***Table 3:** Alberta Power Price Required to Generate a 12% Return on a Natural Gas-Fired Facility*

AECO Natural Gas Assumption (per mcf)	***$3.00***	***$4.00***	***$5.00***
Capacity (MW)	800.0	800.0	800.0
Capacity Factor	85%	85%	85%
Actual Power Generation (GWh)	5,956.8	5,956.8	5,956.8
Capital Cost ($/kW)	1,625.0	1,625.0	1,625.0
Total Capital Cost ($mm)	1,300.0	1,300.0	1,300.0
Debt	60.0%	60.0%	60.0%
Equity	40.0%	40.0%	40.0%
Interest Rate	5.0%	5.0%	5.0%
Depreciation (years)	40	40	40
Income Tax (%)	28.0%	28.0%	28.0%
Fuel ($/MWh)	$21.30	$28.40	$35.50
O&M ($/MWh)	$9.00	$9.00	$9.00
Financial Estimates ($mm)			
Power Revenue	$338.7	$381.0	$423.2
Costs			
Fuel	126.9	169.2	211.5
Operating and Maintenance	53.6	53.6	53.6
Depreciation	32.5	32.5	32.5
Interest Expense	39.0	39.0	39.0
Net Income Before Taxes	**$86.7**	**$86.7**	**$86.7**
Income Tax Expense	24.3	24.3	24.3
Net Income	**$62.4**	**$62.4**	**$62.4**
Average Pool Price Required to Earn an 12% ROE ($/MWh)	**$56.85**	**$63.95**	**$71.05**

Note: Assumes heat rate of 7,100 Btu/kWh
Does not include the future cost of enviromental penalties
Source: BMO Capital Markets

Valuation Methodology

P/E Is Our Primary Valuation Metric for Large-Capitalization Utilities

Given the transparency and predictability of earnings from the large-capitalization utilities, we believe it is appropriate to use the price-to-earnings ratio to derive utility common share prices. Large-capitalization utilities typically have not traded too far from one another and trade within a relatively consistent narrow band of valuation.

***Table 4:** P/E Valuations Trading at the Higher End of the Band*

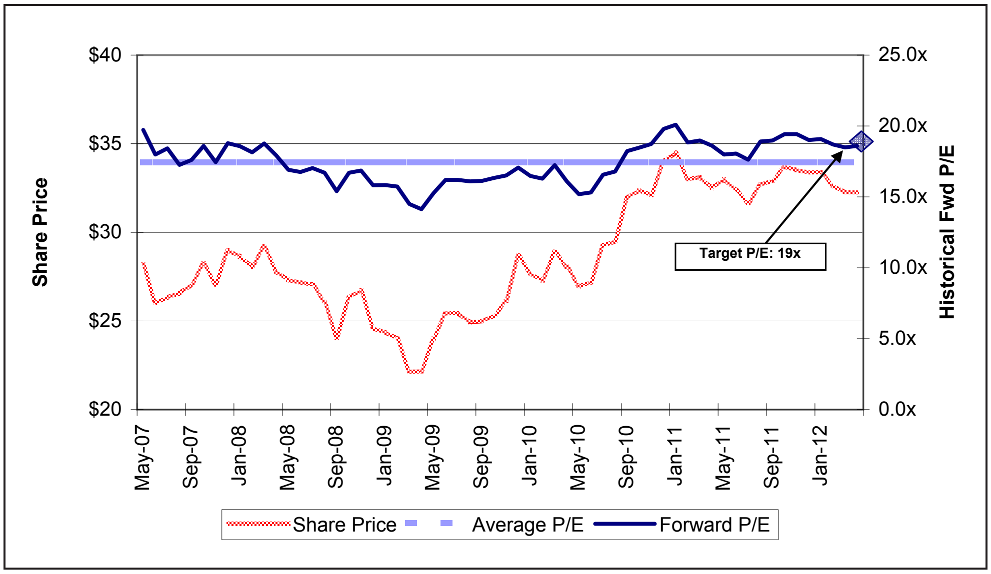
			5-year Fwd. P/E Multiple				Current	Target
		Target					2013E	Valuation
Company	Price	Price	Average	Trough	Peak	2013 EPS	P/E	P/E
Canadian Utilities	$65.84	$70.00	15.2x	11.6x	19.6x	$4.13	16.0x	17.0x
Caribbean Utilities	$10.00	$9.50	13.3x	10.9x	18.6x	$0.70	14.4x	13.5x
Emera	$34.16	$34.00	17.4x	13.6x	19.8x	$1.84	18.5x	18.5x
Fortis	$32.48	$34.50	17.5x	14.1x	20.1x	$1.81	18.0x	19.0x

Source: BMO Capital Markets

FTS: 19x – Due to Superior Earnings Visibility

Over the last five years, Fortis has generally traded at P/E multiples that are higher than its peers, Canadian Utilities and Emera. We believe that the higher multiple is justified given that Fortis generates roughly 90% of its earnings from regulated assets. Also, management has a track record of delivering on expectations. We use 19x our 2013 EPS estimate for our target price derivation, which is the five-year historical average increased by 1.5x to reflect the secular reduction observed in 10-year government of Canada bond yields.

Exhibit 15: *Fortis – P/E, Share Price and Target P/E*

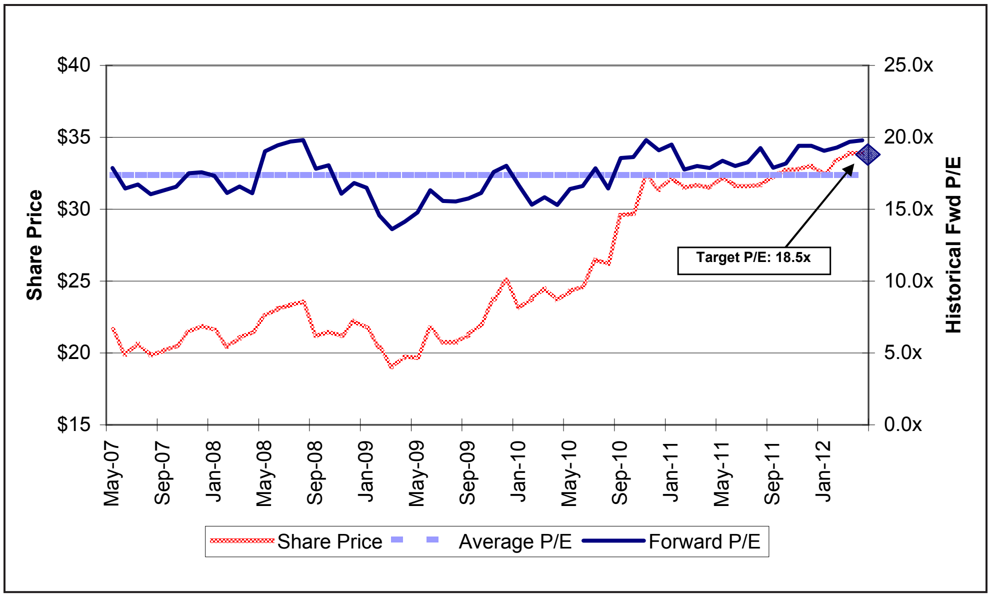


Source: Thomson One, Bloomberg

EMA: 18.5x – Due to a Slightly Higher Business Risk Profile Than Fortis

Over the past five years, EMA has traded at 17.4x its 12-month forward earnings, generally in line with Fortis with a 17.5x average, and a slight premium to the sector average. A slight premium could persist given its recent strong track record of dividend/earnings growth, but we believe EMA should trade at a discount to Fortis as rising fuel costs at Nova Scotia Power may make it difficult for regulators to pass through when the overall rate of Canadian inflation remains well behaved. We use 18.5x our 2013 EPS estimate for our target price derivation.

Exhibit 16: *Emera – P/E, Share Price and Target P/E*

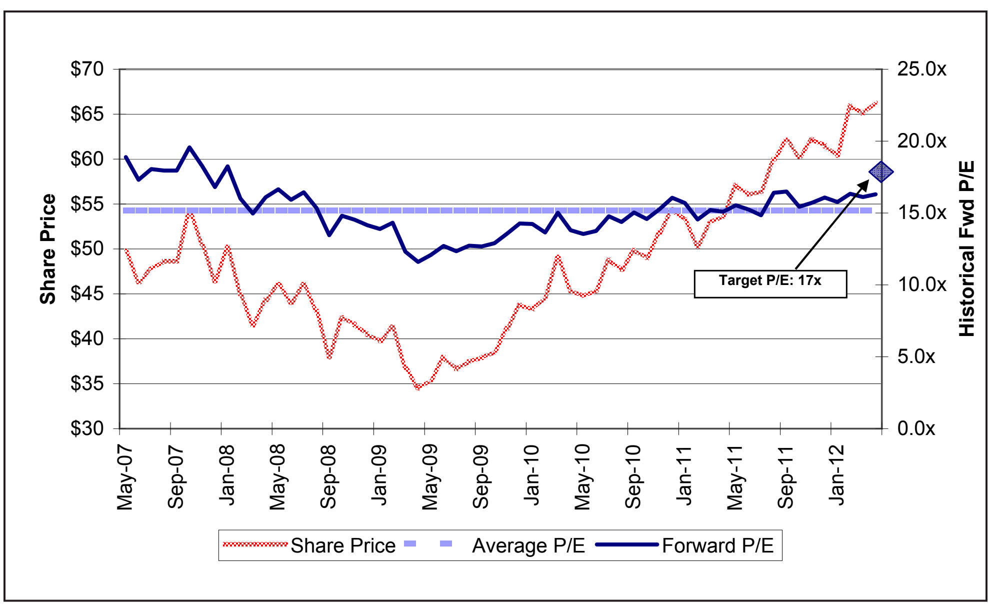


Source: Thomson One, Bloomberg

CU: 17x – Higher Commodity Exposure and Historical Lack of Financial Transparency Drive Lower Multiples

Canadian Utilities has traded at an average of 15.2x forward earnings for the past five years, a discount to the group given its larger exposure to commodity-based assets and a historical lack of financial transparency. However, there is above-average growth in its regulated utility business, its commodity businesses are performing well and financial transparency is improving with more detailed segmented information. We use 17x our 2013 estimated EPS estimate for deriving our target price, which is at the upper end of the five-year average.

Exhibit 17: *CU – P/E, Share Price and Target P/E*



Source: Thomson One, Bloomberg

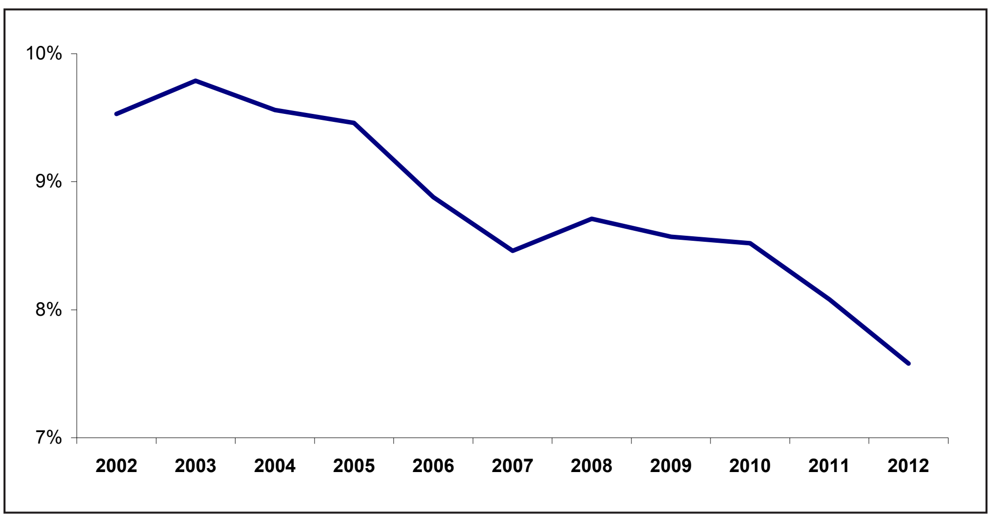
We Use EV/EBITDA as Primary Metric for the Power Producers

The power producers typically exhibit large swings in profitability and on occasion post losses. As a result, we find that for these names, EBITDA is a more useful measure for valuation. Historically, the EV/EBIDTA range for the power names has been between 8x and 12x; currently, the sub-group trades at 8.2x our 2013E EBITDA. As we believe the power markets will remain relatively lukewarm during our forecast period, we believe that multiples will be in the lower end of the historical range. We believe TransAlta should trade at the lower end of its historical range given depressed gas/power prices in the Pacific Northwest and the ongoing Sundance 1/2 saga. These headwinds could limit dividend and earnings growth over our forecast period. Our $19 target price for TA is based on 8.5x 2013E EV/EBITDA, a 1.5x reduction from its five-year average. Our $26 target price for CPX is also based on an 8.5x 2013E EV/EBITDA, which is consistent with the target we use for its closest peer, TransAlta, and a discount to where contracted IPPs are trading given CPX's exposure to merchant power prices.

Regulation Not What It Used to Be

The way Canadian ROEs were calculated was relatively simple and consistent from 1998 until 2009. The National Energy Board's landmark 1998 decision, which established a formula-based return using the change in government bond yield, was mostly adopted by provincial regulators and was used on a uniform basis across the country for utilities operating in those provinces. Although simple, the formula approach to establishing allowed returns led to a systematic reduction in allowed ROEs (Exhibit 18), particularly during the credit crisis, when the utility cost of capital diverged from government bond yields.

Exhibit 18: *NEB Benchmark Return on Equity*



Source: National Energy Board

This led to a general consensus among regulators that the way in which regulated returns were calculated had to change. On one side of the spectrum the National Energy Board simply abandoned its long-standing formula ROE methodology and has become more hands-off in the rate-setting process, allowing the pipeline companies and shippers to negotiate returns. Most provincial regulators held cost-of-capital hearings, which resulted in higher allowed returns and equity thicknesses. Many abandoned the automatic adjustment mechanism (Table 5), effectively de-linking allowed ROEs from government bond yields, but in Ontario the regulator maintained the formula ROE methodology but refined it to incorporate annual changes in utility credit spreads. In Gaz Metro's 2012 rate decision on November 25, 2011, the Régie decided to amend the automatic adjustment mechanism going forward to not only account for the annual changes in government bond yields, but also for the annual changes in the credit spread on long-term bonds of A-rated Canadian utility companies.

These regulatory changes so far are working in favour of equity investors through improved earnings, but uncertainty still lingers over how regulators will establish allowed utility returns in the future. Late last year, the AUC lowered the ROE to 8.75% from 9.00%. The British Columbia Utilities Commission (BCUC) has initiated a cost of capital hearing, which could result in a reduction to the 2013 B.C. ROE given that it is above 9.5%, one of the highest in Canada.

In a low bond yield environment, there will be pressure on ROEs, but we believe Canadian regulatory policy will continue supporting rather than weighing on stock performance for the utility group as a whole.

Table 5: *2010-2012E ROE and Deemed Equity Across Canada*

		Return on Equity			Deemed Equity			Automatic Adjustment Mechanism
Company	**Regulator**	**2010**	**2011**	**2012E**	**2010**	**2011**	**2012E**	
Altalink L.P.	Alberta Utilities Commission	9.00%	9.00%	8.75%	36.0%	37.0%	37.0%	Eliminated
AltaGas Utilities	Alberta Utilities Commission	9.00%	9.00%	8.75%	43.0%	43.0%	43.0%	Eliminated
CU Inc. - ATCO Transmission	Alberta Utilities Commission	9.00%	9.00%	8.75%	36.0%	37.0%	37.0%	Eliminated
ATCO Distribution	Alberta Utilities Commission	9.00%	9.00%	8.75%	39.0%	39.0%	39.0%	Eliminated
ATCO Gas	Alberta Utilities Commission	9.00%	9.00%	8.75%	39.0%	39.0%	39.0%	Eliminated
Enbridge Gas Distribution (1)	Ontario Energy Board	8.39%	8.39%	8.39%	36.0%	36.0%	36.0%	Amended
EPCOR Utilities - Distribution	Alberta Utilities Commission	9.00%	9.00%	8.75%	41.0%	41.0%	41.0%	Eliminated
Transmission	Alberta Utilities Commission	9.00%	9.00%	8.75%	37.0%	37.0%	37.0%	Eliminated
FortisAlberta	Alberta Utilities Commission	9.00%	9.00%	8.75%	41.0%	41.0%	41.0%	Eliminated
FortisBC	British Columbia Utilities Commission	9.90%	9.90%	9.90%	40.0%	40.0%	40.0%	Eliminated
FortisBC Energy	British Columbia Utilities Commission	9.50%	9.50%	9.50%	40.0%	40.0%	40.0%	Eliminated
Gaz Metro L.P. (2)	Regie de l'Energie	9.20%	9.09%	8.90%	38.5%	38.5%	38.5%	Amended
Hydro One - Transmission	Ontario Energy Board	8.39%	9.58%	9.12%	40.0%	40.0%	40.0%	Amended
Distribution	Ontario Energy Board	9.85%	9.66%	9.42%	40.0%	40.0%	40.0%	Amended
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities	9.00%	8.38%	8.38%	45.0%	45.0%	45.0%	Eliminated
Toronto Hydro Corporation	Ontario Energy Board	9.85%	9.58%	9.12%	40.0%	40.0%	40.0%	Amended
Union Gas (1)	Ontario Energy Board	8.54%	8.54%	8.54%	36.0%	36.0%	36.0%	Amended
Average		**9.10%**	**9.10%**	**8.90%**	**39.3%**	**39.4%**	**39.4%**	

Notes:
(1) Base ROE does not change during term of 5-year incentive agreements ending 2012
(2) Gaz Metro's fiscal year-end is September 30; we are restricted on Gaz Metro.
Source: BMO Capital Markets, Regulatory Documents

Alberta

The Alberta Utilities Commission (AUC) regulates the electric, gas, and pipeline utility network in Alberta. The companies in our utility coverage universe that are regulated by the AUC include CU Inc. (electric transmission/distribution, gas distribution) and Fortis Inc. via FortisAlberta (electric distribution). Capital Power L.P. and TransAlta own non-regulated power generation facilities in Alberta.

- **Only province with wholesale power market.** Commencing January 1996, the implementation of the *Electric Utilities Act* and the subsequent introduction in legislature of the *Electric Utilities Amendment Act* in 1998 enabled significant steps toward a competitive power regime in Alberta. An efficient market for generation was established and transmission and generation were functionally unbundled. High-voltage transmission and local distribution systems would continue to be regulated, while generation would be driven by competitive market forces. As part of the transition (effective January 1, 2001), the owners of generating units built before 1995 were entitled to recover their fixed and variable costs based on a rate or formula through long-term contracts (called power purchase arrangements) rather than through market prices for the life of the generating unit, including a life extension period, to a maximum term of December 31, 2020. Many of the coal-fired facilities generating power in Alberta today are governed by power purchase arrangements; however, newer power plants built since that time have been developed on a merchant basis and sell power directly into the market.

- **Approval of CWIP in rate base supports cost of capital.** During 2011, the AUC approved construction work in progress (CWIP) inclusion in rate base for ATCO Electric Transmission for select projects, as part of its tariff application. Recall, under traditional regulatory practice, the CWIP balance is not allowed to earn cash returns until each project's completion. Now, ATCO Electric is allowed to earn cash return on projects that are not completed, providing modest support of cash flow metrics and credit ratings. Given these approvals, we believe that the AUC continues to be supportive of regulatory relief for ATCO Electric Transmission, which in turn should support its overall cost of capital.

- **2012 ROE has declined to 8.75%.** On December 8, 2011, the AUC released its decision on the 2011 Generic Cost of Capital. Highlights include: (i) the AUC decreased the generic ROE to 8.75% from the rate of 9.00% used in 2009–2010; (ii) the AUC concluded that a return to a formula mechanism for annual adjustments to ROE is not warranted at this time and that the ROE for 2012 will be the same as 2011. In addition, the allowed ROE for 2013 will be set at 8.75% on an interim basis; and (iii) while many of the utilities participating in the hearing were not awarded increases in equity thickness, ATCO Electric Transmission (100% CU Inc.) was awarded a 1% increase in its capital structure to 37% to offset the ROE reduction.

- **Electric and gas distributors likely to move to performance based regulation in 2013.** The AUC is also exploring the implementation of Performance Based Regulation (PBR) for distributors in which rates would be adjusted annually by a formula that incorporates inflation and productivity improvements; however, we understand that a final decision on PBR is not expected until mid-2012.

British Columbia

In our coverage universe, Fortis is the only company with significant regulated operations in B.C via FortisBC Energy (largest gas distributor in the province) and FortisBC (integrated electric utility). These utilities are regulated by the BCUC. FortisBC Energy is considered the benchmark low-risk utility in British Columbia, with its ROE the base on which other utility ROEs are determined. The ROE for FortisBC is currently set by applying a 40 bps premium to the ROE set for FortisBC Energy, which equates to 9.90%. We believe the B.C. ROE is most susceptible to a decline, given that it is above 9.5%, one of the highest in Canada. The BCUC has initiated a cost of capital hearing to determine the appropriate rate of return and capital structure for B.C.-based utilities.

Newfoundland

In our coverage universe, Newfoundland Power (100% Fortis Inc.) is the only entity operating in Newfoundland. Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB), a quasi-judicial body established under provincial legislation to regulate public utilities in the province. The Board's authority is derived from its statutory powers and responsibilities as set out in the *Public Utilities Act and the Electrical Power Control Act 1994*. Regulation is designed to ensure consumers receive safe and reliable electricity at rates that are reasonable, while allowing the utility to earn a fair return on its investment in supplying the electrical service.

- **Newfoundland Power is subject to traditional rate base regulation.** The focus of return on rate base regulation is on earnings, in particular, the allowed return per dollar of investment. Rates are set which give the utility the opportunity to recover its revenue requirement, consisting of its estimated operating costs and a fair return on its rate base. Key elements of return on rate base regulation include: (1) Rate Base is the amount of investment on which a regulated utility is allowed to earn a fair return and is primarily comprised of depreciated investment in plant and equipment plus working capital; (2) Capital Structure is the relative amounts of equity and debt that comprise a company's total invested capital. The total invested capital represents the funds invested in the utility by shareholders and by bondholders. The just and reasonable rate of return allowed on rate base is equivalent to the cost of capital representing the sum of the weighted costs of both debt and equity in the capital structure; and (3) Revenue Requirement is the amount of revenue required by a utility to cover the sum of operating costs, including interest costs, depreciation, taxes and allowed return on rate base.
- **Regulator suspends automatic adjustment mechanism.** On December 13, 2011, the PUB issued an order which suspended the operation of the automatic adjustment formula that has been used to calculate Newfoundland Power's return on rate base on an annual basis since 1998. Accordingly, the 2012 ROE will be the same as the 2011 ROE of 8.38%. We believe the elimination of the automatic adjustment formula is long overdue, given where other provincial ROEs are. If the formula had been used again to calculate 2012 returns, we believe returns would have been in the mid-7% range.

Nova Scotia

The electricity system in Nova Scotia is dominated by Nova Scotia Power (100% Emera), which has a monopoly position on the generation, transmission and distribution in the province. The remaining distribution is owned and operated by six municipal utilities. Nova Scotia Power is regulated by the Nova Scotia Utility and Review Board (UARB) under the traditional cost-of-service approach, although customer rates are typically determined through negotiated settlements with customers. On November 29, 2011, the UARB approved Nova Scotia Power's 2012 settlement agreement that was reached with customer representatives on September 29, 2011. The settlement reflected a slight reduction in the regulated ROE to 9.2% from 9.35% on a deemed common equity of 37.5%.

Ontario

Utilities operating in Ontario are regulated by the Ontario Energy Board (OEB). Substantially all of Ontario's transmission is operated and owned by Hydro One. Hydro One also owns the largest distribution system in Ontario, which spans roughly 75% of the province. However, Ontario has the most fragmented electric distribution industry in Canada, with several dozen players operating in select municipalities across the province, including Toronto Hydro. Gas distribution in Ontario is provided by Enbridge Gas Distribution and Union Gas.

- **Refined Ontario ROE formula has been positive.** On November 10, 2011, the OEB issued a letter regarding the 2012 return on equity for use in setting rates, effective January 1, 2012, for natural gas and electricity distribution utilities. Pursuant to the formula set out in the "Report of the Board on the Cost of Capital for Ontario's Regulated Utilities" issued on December 11, 2009, the Board calculated that the ROE to be applied in its consideration of 2012 cost of service applications will be 9.42% versus 9.66% in 2011. Recall, on December 11, 2009, the OEB released its report on the cost of capital for Ontario's regulated utilities. In its report the OEB: (i) reset the base ROE to 9.75% for use in 2010 cost of service applications (up from 8.01% used in 2009); and (ii) maintained a formulaic approach to setting ROE levels, but refined the formula to reduce the sensitivity of the ROE to changes in government bond yields by replacing the previous mechanism with a symmetric 50% sliding scale, such that the allowed ROE is raised or lowered by 50% of the change in the forecast long Canada bond yield and the change in utility corporate bond spread.
- **Future transmission development is now open for competition.** The Province of Ontario is moving to a model where select future transmission projects will undergo a competitive bidding process, pursuant to a policy entitled "Framework for Transmission Project Development Plans" released by the OEB on August 26, 2010. It is our understanding that the policy is intended to encourage new entrants to transmission in Ontario and to support competition in transmission to drive economic efficiency for the benefit of ratepayers. Notably, on August 22, 2011, the OEB issued a letter inviting licensed transmitters and those who have applied for a transmission licence to indicate their intent to file a plan for the development of the East-West Tie Line, one of the five priority transmission projects set out in the current long-term energy plan. The project is expected to increase transfer capacity between the transmission system in the northwest and the rest of Ontario, cost at least $600 million and be in service by 2017.

Quebec

The Régie de l'énergie is Quebec's regulatory authority with primary jurisdiction over the economic regulation of the electricity sector and natural gas distributors. Gaz Metro (we are restricted on Gaz Metro, owned 29% by Valener; we are restricted on Valener, covered by Carl Kirst, BMO Capital Markets Corp.) supplies the majority of natural gas consumed in Quebec. Electricity (generation, distribution, and transmission) is principally served by Hydro-Quebec, a government-owned monopoly with major cost-competitive hydroelectric resources.

- **Gaz Metro is regulated under a hybrid model.** The partnership operates under a performance incentive mechanism (PIM), effective October 1, 2007, and ending September 30, 2012. The PIM has been in effect since October 1, 2000, and is a hybrid model that features elements of traditional cost of service ratemaking and incentive regulation, where the difference between the incentive regulated revenue requirement and the annual revenue requirement determined by a cost of service approach is equal to anticipated productivity gains during a fiscal period. Productivity gains established at the beginning of the fiscal period are shared 50/50 between Gaz Metro and customers, while year-end overearnings are shared 25%/75% by Gaz Metro and customers. Losses identified by the partnership at the beginning of the fiscal period are 100% for the account of the customers, whereas losses realized at year-end are shared 50/50.
- **2012 ROE has declined by 19 bps to 8.90%.** The Regie has set Gaz Metro's fiscal 2012 rates using a ROE of 8.90%, 19 bps lower than the 2011 ROE of 9.09%. In Gaz Metro's 2012 rate decision on November 25, 2011, the Régie decided to amend the automatic adjustment mechanism to not only account for the annual changes in government bond yields, but also the annual changes in the credit spread on long-term bonds of A-rated Canadian utility companies.

Company Profiles

Company Profiles

Boralex

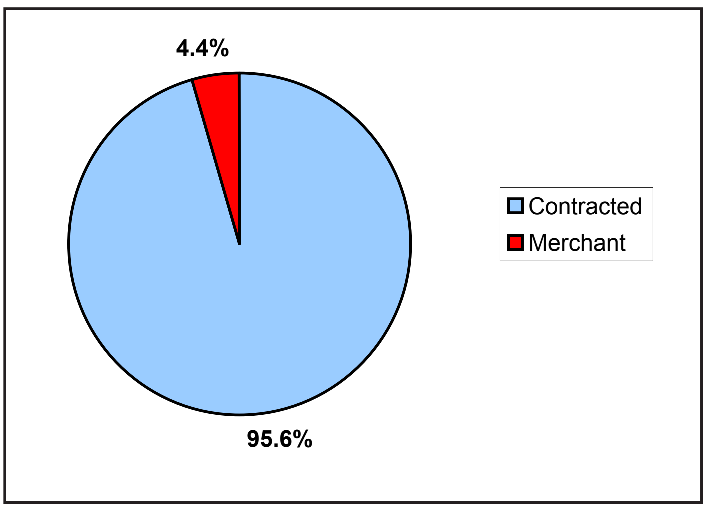
Initiating Coverage at Market Perform; Brighter Days Ahead

Boralex (BLX-TSX)
Price: $8.00 (Apr-5-12)
Target: $9.00

Investment Summary

- **We are initiating coverage of Boralex with a Market Perform rating and a $9 12-month target price**. In our view, Boralex's sale of its U.S.-based biomass power generation assets has served to wipe the slate clean with respect to past weak performance in its biomass division, which we think has weighed on the stock for some time. The sale also significantly redefined its risk profile by reducing its exposure to merchant markets (4% currently vs. 27% previously), a strategic shift we fully endorse. Nonetheless, amid ongoing market turbulence, dividends have firmly moved onto the radar screen for investors; therefore, with the absence of a dividend, we are hard-pressed to identify any near-term catalysts to bridge its valuation gap. Our $9 target price is derived from a discounted cash flow analysis and is supported by our sum-of-the-parts analysis.

***Exhibit 20:** Boralex – 2011 Electricity Market Exposure (MW)*



Source: BMO Capital Markets, Company reports

- **Approximately $200 million float**. BLX is not very liquid, averaging ~40,000 shares traded per day over the last 100 days. There are approximately 37.7 million shares outstanding. 35% or 13.2 million shares are owned by Cascades (CAS-TSX, $5.75, Outperform, covered by Stephen Atkinson). The public float is therefore approximately 24.5 million.

- **A lot of dry powder**. At year-end 2011, Boralex had $163 million ($4.32/share) of cash, including the net proceeds from the sale of the U.S. biomass portfolio. Although BLX has a sizable war chest, it does not pay a dividend, unlike its peers. The decision to retain cash rather than pay a dividend is driven by the company's large organic growth pipeline, which will require significant equity contributions during the next few years.

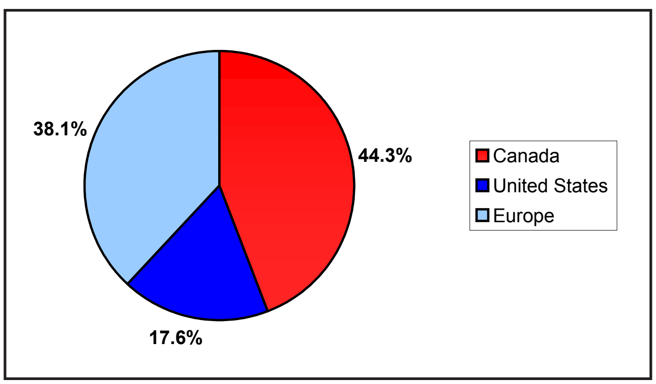
Rather than raise external equity, BLX is of the view that it is more prudent to finance growth initiatives using a combination of cash on hand to finance its remaining slate of projects. In addition, the company is also targeting future investment of up to $400 million in contracted wind (and possibly hydro and solar) located either in Canada or Europe. We currently do not account for these opportunities in our target price (see 7 for potential growth pipeline).

- **Seigneurie de Beaupré**. In terms of its major growth initiatives, BLX's $700–725 million (100% basis) Seigneurie de Beaupré (Phase I) wind project is slated to come on-stream at the end of 2013 and is expected to add nameplate capacity of 136 MW to its 50% share. Phase 2 could follow a year later, adding a further 35 MW net. Management has indicated that it would consider the initiation of a dividend once Phase I of the wind farm is commissioned.
- **Earnings estimates**. We are introducing EPS forecasts of ($0.07) in 2012 and ($0.29) in 2013.

Assets Include All Renewable Fuel Sources

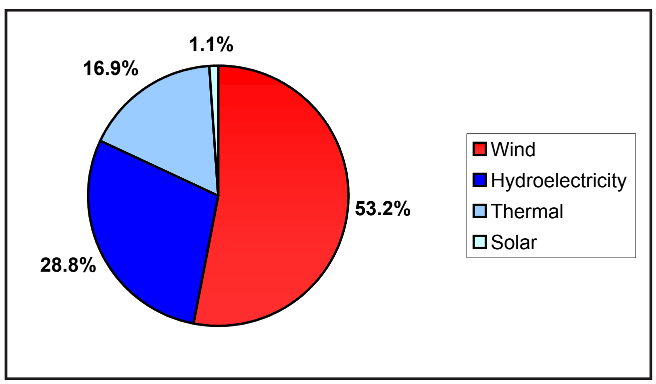
Boralex Inc. is an independent power producer whose core business is the development and operation of renewable power facilities, with a focus on wind, hydro, thermal and more recently solar. Boralex currently operates 500 MW of capacity in Canada, the Northeast U.S. and France. It also has roughly 400 MW of power projects in various stages of development. Boralex was founded in 1982, but its role as a developer of renewable energy commenced in 1995 after Cascades Energy Inc., the power generation arm of Cascades Inc., created Boralex through a reverse takeover. Cascades currently holds a 35% ownership interest in Boralex. Boralex trades on the Toronto Stock Exchange under the ticker symbol BLX.

Exhibit 21: *Capacity by Geography*



Source: BMO Capital Markets, Company reports

Exhibit 22: *Capacity by Fuel Type*



Source: BMO Capital Markets, Company reports

Boralex's operating facilities are listed in Table 6, and its construction pipeline and development projects are listed in Table 7.

Table 6: *Operating Facilities*

Facility	Location	Fuel Type	Ownership Interest (%)	Net Installed Capacity (MW)	Gross Expected Output (GWh)	Expected Utilization (%)	Electricity Purchaser	PPA Expiry
Ally-Mercoeur	France	Wind	95.0%	39.0	78.0	22.8%	EDF	2020
Avignonet-Lauragais	France	Wind	65.0%	12.5	30.0	27.4%	EDF	2017
Cham Longe	France	Wind	95.0%	22.5	72.0	36.5%	EDF	2020
Chépy	France	Wind	85.0%	4.0	7.0	20.0%	EDF	2018
La Citadelle	France	Wind	100.0%	14.0	33.0	26.9%	EDF	2022
Nibas	France	Wind	95.0%	12.0	22.0	20.9%	EDF	2019
Plouguin	France	Wind	100.0%	8.0	22.0	31.4%	EDF	2020
Ronchois	France	Wind	100.0%	30.0	72.0	27.4%	EDF	2025
Chasse-Marée	France	Wind	100.0%	9.0	24.0	30.4%	EDF	2025
Le Grand Camp	France	Wind	100.0%	10.0	28.0	32.0%	EDF	2025
Thames River	Ontario	Wind	100.0%	90.0	243.0	30.8%	OPA	2030
East Angus	Quebec	Hydro	100.0%	2.0	14.0	79.9%	H-Q	2010
Huntingville	Quebec	Hydro	100.0%	0.5	1.0	22.8%	H-Q	2021
Fourth Branch	New York	Hydro	100.0%	3.0	13.0	49.5%	NYISO	Merchant
Middle Falls	New York	Hydro	100.0%	2.0	10.0	57.1%	NMP	2014
New York State Dam	New York	Hydro	100.0%	11.5	50.0	49.6%	NYISO	Merchant
Sissonville	New York	Hydro	100.0%	3.0	14.0	53.3%	NYISO	Merchant
Warrensburg	New York	Hydro	100.0%	3.0	11.0	41.9%	NYISO	Merchant
Hudson Falls	New York	Hydro	100.0%	46.0	215.0	53.4%	NMP	2035
South Glen Falls	New York	Hydro	100.0%	14.0	75.0	61.2%	NMP	2034
Ocean Falls	BC	Hydro	100.0%	14.5	16.0	12.6%	BC Hydro	2016
Forestville	Quebec	Hydro	100.0%	12.5	44.0	40.2%	H-Q	2013
Rimouski	Quebec	Hydro	100.0%	3.5	21.0	68.5%	H-Q	2017
Beauport	Quebec	Hydro	100.0%	4.5	21.0	53.3%	H-Q	2015
St-Lambert	Quebec	Hydro	100.0%	6.0	39.0	74.2%	H-Q	2020
Buckingham	Quebec	Hydro	100.0%	10.0	74.0	84.5%	H-Q	2019
Senneterre	Quebec	Biomass	100.0%	35.0	210.0	68.5%	H-Q	2027
Kingsey Falls	Quebec	Natural Gas	100.0%	31.0	200.0	73.6%	H-Q	2012
Blendecques (1)	France	Natural Gas	100.0%	14.0	39.0	31.8%	EDF	2013
Avignonet-Lauragais	France	Solar	100.0%	5.0	5.4	12.3%	EDF	2031
Total				**472.0**	**1,703.4**			

Notes:
EDF = Électricité de France; NYISO = New York Independent System Operator; OPA = Ontario Power Authority; NMP = Niagara Mohawk Power; H-Q = Hydro-Québec

(1) The Blendecques facility also sells approximately 500,000 tons of steam to Norampac avot-Vallee S.A. under a 20-year contract that expires in 2021.

Source: BMO Capital Markets, Company Reports

Table 7: Construction Pipeline and Project Portfolio

Facility	Location	Fuel Type	Ownership Int. (%)	Net Capacity (MW)	Expected In-Service Date	Est. Capital Cost ($ mm)	Est. Equity Required ($ mm) (1)	Source of Equity	Firm Project?
Potential JV Investments With CUBE Infrastructure Fund	Europe	Wind	70% (2)	31.5	2011-2012	100	n/a (2)	CUBE	No
Potential New Investments From Redeployment of US Biomass Capital (3)	Canada/ Europe	Wind	70 - 100%	Up to 165	2012-2013	400-425	85.0	Biomass proceeds	No
Seigneurie de Beaupré - Phase 1	Quebec	Wind	50.0%	136.0	2013	700-725	100.0	Cash flow	Yes
Seigneurie de Beaupré - Phase 2	Quebec	Wind	50.0%	34.5	2014	180-190	25.0	Cash flow	Yes
Municipal Temiscouata	Quebec	Wind	51.0%	12.8	2014	65-70	10.0	Cash flow	Yes
Municipal Seigneurie de Beaupre	Quebec	Wind	51.0%	12.8	2015	65-70	10.0	Cash flow	Yes
Total				**392.6**		**1,510-1,580**	**230.0**		

Notes:
(1) Boralex's share.
(2) Equity component of the project will be funded pursuant to the partnership with CUBE Infrastructure Fund. Per the agreement, CUBE's interest in the JV will increase to a maximum of 30%, upon CUBE's investment of an incremental €9 mm in new equity.
(3) Redeployment of proceeds from the sale of the U.S. biomass assets. Assumes that the $81 million in net proceeds will be invested in wind projects at a capital cost of $2.5 million/MW using a capital structure of 80% debt and 20% equity.
Source: BMO Capital Markets, Company Reports

Earnings Estimates

We are introducing the following estimates for 2012 and 2013.

Table 8: Boralex Estimates

	2012E	2013E
Revenue	**196.7**	**168.3**
Total operating costs	96.2	77.2
EBITDA	**100.4**	**91.1**
% of revenue	51.1%	54.1%
Net earnings	**(2.6)**	**(11.0)**
Cash Flow From Operations	**53.8**	**47.6**
Average shares o/s (basic & diluted)	37.7	37.7
CFPS (basic & diluted)	$1.43	$1.26
EPS (basic & diluted)	($0.07)	($0.29)
First Call Consensus	($0.11)	($0.29)

Source: BMO Capital Markets, Thomson ONE

Valuation – Target Price $9

We determine our $9 target price for Boralex based on a discounted cash flow analysis, given the highly contracted nature of its current assets and its infrastructure backlog. Our key assumptions include a discount rate of 6.34% per annum (60% debt at a pre-tax cost of 6% and 40% equity at a cost of 10%), a long-term effective tax rate of 35% and a terminal growth rate of 1.0%. Our terminal value calculation assumes recurring capital expenditures that are equal to depreciation. The sensitivity of the valuation to these assumptions is shown below.

***Table 9:** Discounted Cash Flow Analysis*

	2011	2012E	2013E	2014E	2015E	2016E	2025E	TV
NPV Calculation ($ mm)								
Cash Flow From Operations		53.8	47.6	60.5	73.2	75.1	99.7	99.7
Less: Capital Expenditures		(63.4)	(337.2)	(103.5)	(37.5)	(37.5)	0.0	(86.4)
Add: After-tax Interest Costs		35.3	40.0	44.9	45.2	46.9	32.9	32.9
Free Cash Flow to Firm		25.7	(249.7)	1.9	81.0	84.5	132.6	46.2
Cash on Hand	163.0							
Long-Term Debt	(506.2)							
Convertible Debentures	(223.3)							
Terminal Value								**865.9**
Undiscounted Cash Flow	**(566.5)**	**25.7**	**(249.7)**	**1.9**	**81.0**	**84.5**	**132.6**	**865.9**
Discount Factor	1.000	0.940	0.884	0.832	0.782	0.735	0.423	0.423
Discounted Cash Flow	**(566.5)**	**24.1**	**(220.8)**	**1.6**	**63.3**	**62.1**	**56.1**	**366.2**
Net Present Value	**339.5**							
Shares Outstanding	37.7							
Net Present Value per Share	**$9.00**							

WACC Calculation	**After-Tax Cost**	**Weight**	**Wtd. Avg.**
Debt	3.9%	60.0%	2.3%
Equity	10.0%	40.0%	4.0%
Tax Rate	35.0%		
WACC			**6.3%**
Other Information			
Long-Term Growth Rate	1.0%		

Source: BMO Capital Markets

***Table 10:** Target Price Sensitivity to Cost of Equity and Terminal Growth Rate*

		Growth Rate					
		0.00%	**0.50%**	**1.00%**	**1.50%**	**2.00%**	**2.50%**
Discount Rate	**8.50%**	$10.00	$10.93	$12.06	$13.46	$15.23	$17.54
	9.00%	$9.11	$9.95	$10.97	$12.21	$13.78	$15.79
	9.50%	$8.26	$9.03	$9.95	$11.07	$12.45	$14.22
	10.00%	$7.47	$8.17	**$9.00**	$10.00	$11.23	$12.79
	10.50%	$6.71	$7.35	$8.11	$9.01	$10.11	$11.49
	11.00%	$6.00	$6.58	$7.27	$8.09	$9.08	$10.30
	11.50%	$5.32	$5.85	$6.48	$7.22	$8.11	$9.21

Source: BMO Capital Markets

Although we utilize a DCF analysis as our dominant approach to value BLX shares, we also perform a sum-of-the-parts analysis as a secondary measure to support our valuation. As illustrated in Table 11, we apply a targeted EBITDA multiple to our 2014E outlook (capturing the contribution of the Seigneurie de Beaupré wind farm), and discount that by 10% per annum to approximate a value for 2012E.

Table 11: *Sum-of-the-Parts Supports Valuation*

	2014E EBITDA	EV/EBITDA Multiple	Implied Enterprise Value
Wind	100.5	10.0x	1,004.5
Hydro	42.4	11.0x	466.8
Solar	3.0	10.0x	30.0
Corporate costs	(20.5)	9.0x	(184.5)
Convertible Debentures			(223.3)
Long-term debt			(822.0)
Cash			135.6
			407.1
Shares o/s			37.7
2014E net equity ($/share)			$10.79
Discount rate of 10%			0.83
2012E net equity ($/share)			**$8.92**

Source: BMO Capital Markets

Investment Risks

1. **Limited Liquidity**: The shares of Boralex trade very thinly. The relatively smaller market cap size of the company and significant equity ownership by Cascades, in our view, limit trading volumes in the stock and add to share price volatility.
2. **Operating Risk**: The generation of electricity is a highly mechanical process. All of the company's facilities must be properly maintained if they are to operate in a manner that is consistent with our estimates.
3. **Counterparty Risk**: BLX is subject to numerous contracts (PPA and construction contracts being the most important) and, therefore, is exposed to counterparty risk. The financial performance of the company is dependent on the performance of its counterparties.
4. **Construction and Approval Risk**: Our estimates depend on the company's projects being completed on time and on budget. A delay in the planned schedule or an increase in costs could negatively affect our estimates and valuation.

Boralex Management Team

Table 12: *Management Overview*

Name	Position	Employment History
Patrick Lemaire	President and Chief Executive Officer	- Mr. Lemaire has been the CEO and President of Boralex Inc. since September 4, 2006. Prior to that he served as COO and VP of Container Board of Norampac Inc. since September 2001. - Mr. Lemaire also served as General Manager for several of Norampac Inc.'s container mills from May 1998 to September 2001 and he served as Mill Manager in several of Norampac Inc.'s and Cascades' container board mills from August 1993 to May 1998.
Jean-Francois Thibodeau	Vice-President and Chief Financial Officer	- Mr. Thibodeau has served as VP and Chief Financial Officer of Boralex Inc. since October 6, 2003. Prior to that he served as the VP and Treasurer of CAE Inc. since 2001, Corporate Treasurer of G.T.C. Transcontinental Group Ltd., from 1999 to 2001 and Director of Finance and Treasury of Provigo from 1997 to 1999.
Sylvain Aird	Vice-President, Legal Affairs and Corporate Secretary	- Mr. Aird has been with Boralex as a VP, Legal Affairs and Corporate Secretary since September 2004. Prior to that he has worked as a Legal Counsel for TransEnergie and Abitibi Consolidated.

Source: Company reports

Table 13: *Consolidated Summary Sheet*

	Year Ended 31 December									CAGR 2011A-2013E
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012E**	**2013E**	
EPS (basic)	$0.69	$0.49	$0.63	$0.54	$0.39	($0.15)	($0.07)	($0.07)	($0.29)	
EPS (diluted)	$0.69	$0.48	$0.62	$0.54	$0.39	($0.15)	($0.07)	($0.07)	($0.29)	
First Call Consensus								*($0.11)*	*($0.29)*	
CFPS (diluted)	$0.87	$0.82	$1.50	$1.46	$1.00	$0.98	$1.54	$1.43	$1.26	-9.5%
Dividends per Share	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Average Shares o/s (mm)	30.0	30.0	34.4	37.7	37.7	37.7	37.8	37.7	37.7	
Net Book Value	$5.51	$6.06	$7.60	$9.61	$9.01	$9.69	$8.53	$8.46	$8.17	
Market Valuation										
Price: High	$8.85	$11.20	$19.00	$18.00	$9.96	$10.65	$9.36	-	-	
Price: Low	$5.40	$8.05	$10.50	$6.62	$5.00	$7.40	$5.97	-	-	
Price: Current	-	-	-	-	-	-	-	$8.00	-	
P/E Ratio: High	12.9	23.1	30.9	33.6	25.6	nmf	nmf	-	-	
P/E Ratio: Low	7.9	16.6	17.1	12.4	12.9	nmf	nmf	-	-	
P/E Ratio: Current	-	-	-	-	-	-	-	nmf	nmf	
EV/EBITDA: High	13.8	13.3	13.6	12.7	11.0	17.9	10.8	-	-	
EV/EBITDA Value: Low	10.8	11.1	8.8	6.4	7.7	16.0	9.5	-	-	
EV/EBITDA: Current	-	-	-	-	-	-	-	10.7	14.5	
Price/Book Value: High	1.6	1.8	2.5	1.9	1.1	1.1	1.1	-	-	
Price/Book Value: Low	1.0	1.3	1.4	0.7	0.6	0.8	0.7	-	-	
Price/Book Value: Current	-	-	-	-	-	-	-	0.9	1.0	
Balance Sheet ($mm)										
Debt (S-T)	1.2	0.0	0.0	0.0	12.3	0.2	0.0	0.0	0.0	
Debt (L-T)	202.6	234.3	180.2	191.7	236.2	513.6	506.2	533.3	771.8	
Convertible Debentures	0.0	0.0	0.0	0.0	0.0	220.8	223.3	223.3	223.3	
Non-Controlling Interest	1.0	0.7	0.6	0.8	7.0	8.9	7.1	17.6	20.9	
Shareholders Equity	165.2	182.0	284.8	362.7	340.0	365.8	321.8	319.2	308.3	
	370.1	417.1	465.5	555.3	595.5	1,109.3	1,058.5	1,093.4	1,324.3	
Balance Sheet (%)										
Debt (S-T)	0.3%	0.0%	0.0%	0.0%	2.1%	0.0%	0.0%	0.0%	0.0%	
Debt (L-T)	54.8%	56.2%	38.7%	34.5%	39.7%	46.3%	47.8%	48.8%	58.3%	
Convertible Debentures	0.0%	0.0%	0.0%	0.0%	0.0%	19.9%	21.1%	20.4%	16.9%	
Non-Controlling Interest	0.3%	0.2%	0.1%	0.1%	1.2%	0.8%	0.7%	1.6%	1.6%	
Shareholders Equity	44.6%	43.6%	61.2%	65.3%	57.1%	33.0%	30.4%	29.2%	23.3%	
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
Income Statement ($mm)										
Total Revenue	135.5	150.9	189.7	225.8	204.5	204.8	194.7	196.7	168.3	-7.0%
EBITDA	34.1	42.8	61.3	68.9	57.3	64.0	100.9	100.4	91.1	-5.0%
EBIT	22.7	21.6	39.7	44.4	31.3	23.3	43.1	46.2	33.9	-11.3%
Net Earnings	20.8	14.7	21.5	20.4	14.7	(5.7)	2.9	(2.6)	(11.0)	
Cash Flow from Operations	26.2	24.5	51.5	55.3	37.7	37.0	58.1	53.8	47.6	-9.6%
Operating Statistics										
Installed Capacity (average MW)	255.6	316.7	344.6	351.0	365.5	634.8	638.6	471.6	440.6	
Potential Energy Capacity (net GWh)	2,239.2	2,774.3	3,018.6	3,074.8	3,170.0	3,964.6	5,594.1	4,087.4	3,815.9	
Saleable Production (net GWh)	1,205.3	1,377.1	1,544.2	1,623.3	1,574.9	2,044.8	2,355.9	1,696.6	1,481.5	
Capacity Utilization (%)	53.8%	49.6%	51.2%	52.8%	49.7%	51.6%	42.1%	41.5%	38.8%	
Percentage Change in Production	-4.3%	14.2%	12.1%	5.1%	-3.0%	29.8%	15.2%	-28.0%	-12.7%	
Revenue ($/MWh) - All Facilities	$90.18	$87.14	$105.78	$121.51	$117.33	$91.49	$ 103.71	$ 114.63	$ 112.11	

Note: Priced as of market close on April 5, 2012.
Source: BMO Capital Markets, Company Reports

Capital Power

Initiating Coverage at Outperform; The Future Looks Bright

Capital Power (CPX-TSX)
Price: $23.40 (Apr-5-12)
Target: $26

Investment Summary

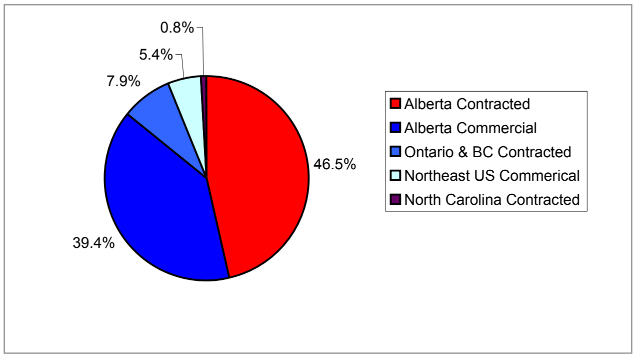
- **We are initiating coverage of Capital Power with an Outperform rating and a $26 target price**. As a growth-oriented power producer, Capital Power's recent relative valuation compression reflects a multitude of market concerns ranging from uncertainty regarding the direction of Alberta power prices to the large equity overhang. While these are legitimate considerations, we believe Capital Power's solid operating performance has largely gone unnoticed. Fleet availability has averaged 93% over the last four years, in part a reflection of its young fleet (average age of ~12 years) and management's sharp focus on operational excellence. In our view, the path to a higher relative valuation for Capital Power revolves around continued strong operating metrics and EPCOR Utilities' divestment of its remaining ~29% interest in Capital Power. Not to be overlooked is the fact that with the sale of its interest in Capital Power Income in the rear-view mirror, CPX is structurally cleaner and more strategically focused, in our view. We also believe there is a reasonable likelihood that Capital Power will raise its common share dividend of $1.26 (5.4% yield) per share in 2014. Our $26 target price for CPX is based on 8.5x 2013E EV/EBITDA, which is consistent with the target we use for its closest peer, TransAlta, and a discount to where contracted IPPs are trading given CPX's exposure to merchant power prices.
- **Highest Alberta power price leverage**. Despite a number of acquisitions/developments outside Alberta, Capital Power is still more levered to Alberta Power prices than any other company in our coverage universe. As a result, the primary driver of near-term share price performance will likely be the direction of Alberta Power prices, which in general has proven to be quite volatile. We estimate that a $5/MW change in power price will impact EPS by $0.15 in 2012 and $0.23 in 2013. We do note that the company is 48% hedged for 2012, reducing downside risk in earnings this year. Looking ahead into 2013, CPX currently is hedged only 20% at a mid-$60/MWh power price, but our sense is that with no new significant generation supply entering the Alberta market until 2015, reserve margins should remain tight for 2013/14, allowing the company the opportunity to hedge 2013 generation at attractive prices as the year goes by.
- **Potential catalysts.** In terms of Capital Power's potential catalysts the following are key: (1) sanctioning K2 wind and the Port Dover/Nanticoke projects; (2) bringing Halkirk and Quality Wind onstream in the fourth quarter; (3) the possibility of a dividend bump; and (4) posting respectable production and operating metrics.
- **Equity issuance overhang remains**. Other than the prospect of weak Alberta Power prices, the second biggest risk to the Capital Power story, in our view, is the large equity issuance overhang. Since the CPX IPO in mid-2009, EPCOR has significantly sold down its stake in CPX to ~29% from 72% . EPCOR intends to fully divest its investment in

CPX over time, subject to market conditions and its need for capital, which could have negative pricing implications for prevailing CPX shares. The good news is that with a larger public float, CPX shares should benefit from enhanced liquidity.

- **Earnings estimates**. We are introducing EPS forecasts of $1.44 in 2012 and $1.64 in 2013.
- **Attractive relative valuation**. At current levels, CPX is relatively inexpensive, trading at 8.4x 2013E EV/EBITDA (vs. 8.0x for TA and 11.1x for regulated utilities).

Exhibit 23: *Capital Power at a Glance*

2011 EBITDA Resides Mainly in Alberta



Note: (1) Exludes results from CPILP plants, other portfolio activities and corporate segments.

(2) Northeast US assets were acquired in April 2011

(3) In November 2011, CPX acquired the North Carolina assets from Capital Power Income L.P.

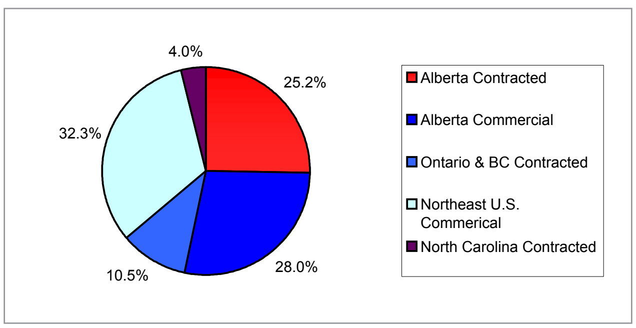
Upcoming Events/Potential Catalysts

April 2012	Q1/12 Results
April 27, 2012	Annual General Meeting
Summer 2012	Final Federal environmental rules for coal-fired generation
July 2012	Q2/12 Results
Oct. 2012	Q3/12 Results
Late 2012	Annual Investor Day
During 2012	Sanctioning of Port Dover/Nanticoke and K2 projects
Late 2012/Early 2013	Expected in-service of Halkirk and Quality Wind projects
Late 2013/Early 2014	Expected in-service of Port Dover/Nanticoke and K2 projects
2014	Possible dividend increase

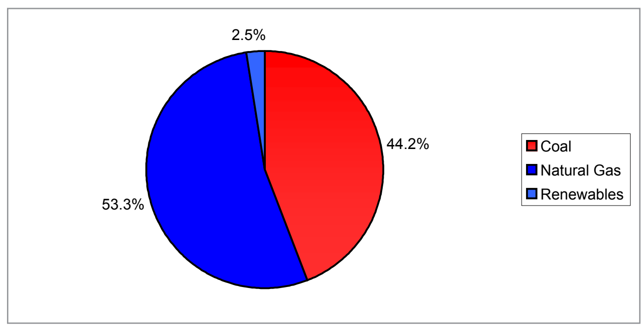
Selected Financing History

05-Apr-12	$200mm secondary offering of 8.5mm shares at $23.55
21-Feb-12	$250mm debt offering with 4.85% coupon
10-Nov-11	$224.5mm secondary offering of 9.2mm shares at $24.40
12-Jul-11	$200.8mm common share offering of 8.0mm shares at $25.10
15-Jun-11	US$295mm debt offering with coupon of 5.21%/5.61% (10yr/15yr)
18-Apr-11	$300mm debt offering with coupon of 4.6%
17-Mar-11	$201.7mm common share offering of 8.1mm shares at $24.90
16-Dec-10	$125mm preferred share offering with 4.6% coupon
14-Dec-10	$200mm secondary offering of 8.334mm shares at $24.00

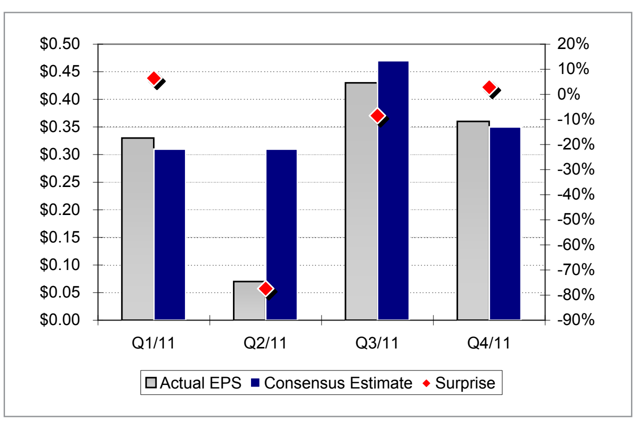
Capital Power - Net Capacity by Geography



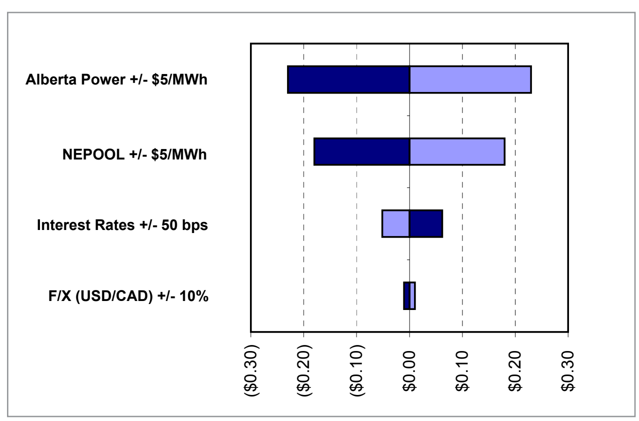
2011 Net Capacity Primarily Coal and Gas



Consensus vs. Estimates



Sensitivities



Source: Company Reports, BMO Capital Markets

Corporate Overview

Capital Power is a growth-oriented independent power producer whose core business is developing and operating power generation stations. It was spun out of EPCOR Utilities in July 2009. Capital Power's fleet produces electricity from 16 facilities across North America, with a total capacity of over 3,300 MW (see Table 14). An additional 371 MW of capacity is owned through power purchase arrangements and the company is in the process of developing power generation projects with a net capacity of 487 MW (Table 15) in Alberta, British Columbia and Ontario. EPCOR currently owns a ~29% economic interest in CPX and has stated that it intends to fully sell its ownership interest over time.

In 2011, roughly 89% of EBITDA was sourced from Alberta. Although several wind projects are expected to be commissioned over our forecast period, CPX's EBITDA exposure will continue to be largely driven by Alberta. Capital Power has stated that it intends to maintain a portfolio that is approximately 50% contracted and 50% merchant.

For financial reporting purposes, Capital Power groups its assets based on geography and the nature of revenue. A description of the assets and the markets in which they operate is set out below.

Table 14: *Assets by Geographic Region*

Facility	Location	Fuel Type	Ownership Interest (%)	Installed Capacity (MW)	Net Capacity (MW)	Electricity Purchaser	PPA Expiry	In-Service Date
Alberta Contracted Facilities								
Genesee 1	Alberta	Coal	100.0%	422.0	422.0	AB Balancing Pool	2020	1994
Genesee 2	Alberta	Coal	100.0%	430.0	430.0	AB Balancing Pool	2020	1989
Subtotal			**100.0%**	**852.0**	**852.0**			
Alberta Commercial Facilities								
Keephills 3 (1)	Alberta	Coal	50.0%	495.0	247.5	Merchant	Merchant	2011
Genesee 3	Alberta	Coal	50.0%	516.0	258.0	Merchant	Merchant	2005
Clover Bar Unit 1	Alberta	Natural Gas	100.0%	43.4	43.4	Merchant	Merchant	2008
Clover Bar Units 2&3	Alberta	Natural Gas	100.0%	200.0	200.0	Merchant	Merchant	2009
Joffre (2)	Alberta	Natural Gas	40.0%	480.0	192.0	Nova/Merchant	Merchant	2000
Clover Bar Landfill Gas	Alberta	Biogas	100.0%	4.8	4.8	Merchant	Merchant	2005
Subtotal			**54.4%**	**1,739.2**	**945.7**			
Ontario & BC Contracted Facilities								
Kingsbridge 1	Ontario	Wind	100.0%	40.3	40.3	OPA	2027	2006
Miller Creek	BC	Hydro	100.0%	33.0	33.0	BC Hydro	2023	2003
Brown Lake	BC	Hydro	100.0%	7.0	7.0	BC Hydro	2016	1996
Island Generation	BC	Natural Gas	100.0%	275.0	275.0	BC Hydro	2022	2002
Subtotal			**100.0%**	**355.3**	**355.3**			
Northeast U.S. Commercial Facilities								
Tiverton	RI	Natural Gas	100.0%	279.0	279.0	Merchant	Merchant	2000
Rumford	ME	Natural Gas	100.0%	270.0	270.0	Merchant	Merchant	2000
Bridgeport	CT	Natural Gas	100.0%	540.0	540.0	Merchant	Merchant	1999
Subtotal			**100.0%**	**1,089.0**	**1,089.0**			
North Carolina Contracted Facilities								
Roxboro	NC	Coal/Solid Fuel	100.0%	46.0	46.0	Progress Energy	2021	1987
Southport	NC	Coal/Solid Fuel	100.0%	88.0	88.0	Progress Energy	2021	1987
Subtotal			**100.0%**	**134.0**	**134.0**			
Total				**4,169.5**	**3,376.0**			

Note: (1) Keephills 3 was constructed by Capital Power. The facility is operated by TransAlta Corp.
(2) Joffre was constructed and is operated by ATCO Power, a subsidiary of Canadian Utilities Ltd.
Source: BMO Capital Markets, Company Reports

Alberta Contracted Plants

Capital Power's Genesee 1 and 2 facilities were constructed before the Alberta power market was de-regulated. Genesee 1 was completed in 1994, and Genesee 2 was commissioned in 1989. As part of the process to de-regulate Alberta's electricity industry, all power generation facilities that were constructed before January 1, 1996, were awarded power purchase agreements (PPAs). These PPAs were designed to provide legacy generators with the ability to recover their fixed and variable costs, and receive a return on invested capital similar to what they would have been entitled to under rate regulation. Most PPAs, including the PPAs that govern the operation of Genesee 1 and 2, contain parameters that provide generators with incentives or penalties, depending on the operating performance of the facilities.

In 2000, the Government of Alberta sold all of these newly created power purchase agreements through an auction. In essence, those who acquired PPAs (PPA counterparties) own the rights to electricity produced by specific legacy generators. PPA counterparties must pay the legacy generators for their output according to the terms and conditions specified in the PPAs; however, the PPA counterparties are free to use the electricity acquired for their own purposes or remarket the electricity in the Power Pool of Alberta. All transactions between legacy assets governed by PPAs and the PPA counterparties settle through the Alberta Balancing Pool.

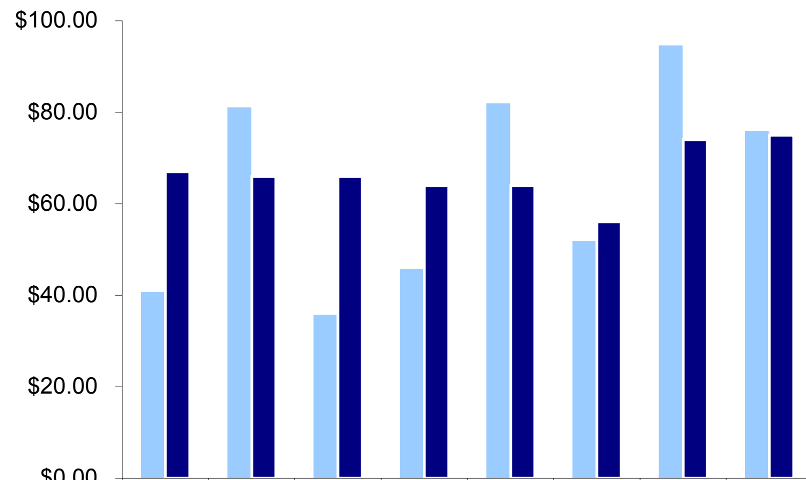
As Genesee 1 and 2 are legacy thermal generators, they receive revenue pursuant to their respective power purchase agreements and are not directly exposed to spot market prices.

Alberta Commercial Plants and Portfolio Optimization

Capital Power's Alberta Commercial assets consist of seven facilities with an aggregate capacity of approximately 1,739 MW (946 MW net to Capital Power). These plants generate electricity from a variety of fuel sources, including coal, natural gas and landfill gas. Output from these plants (with the exception of a portion of Joffre's capacity, which is sold pursuant to a power purchase agreement with NOVA Chemicals) is marketed into the Power Pool of Alberta by Capital Power's commodity portfolio management group. The commodity portfolio group follows a "networked hub" strategy where assets are dispatched in a manner designed to maximize the value of Capital Power's entire portfolio, rather than maximizing the profitability of any specific power plant. Portfolio risk is managed through the use of physical and financial contracts. Trading counterparties include other power generators, large load customer entities and energy trading subsidiaries of financial organizations.

Although merchant facilities carry more risk than contracted assets, during the last eight quarters Capital Power has done a fairly good job of locking in above-market power prices. CPX has achieved above spot prices in four out of the last eight quarters. A comparison of actual average Alberta power prices and the power prices realized by Capital Power's merchant power plants and energy trading group is set out in Exhibit 24.

Exhibit 24: *Alberta Power Prices vs. CPX's Realized Prices*



	Q1/10	Q2/10	Q3/10	Q4/10	Q1/11	Q2/11	Q3/11	Q4/11
Average Alberta Price	$40.78	$81.15	$35.77	$45.95	$82.03	$51.90	$94.69	$76.05
Realized Power Price	$67.00	$66.00	$66.00	$64.00	$64.00	$56.00	$74.00	$75.00

Source: Company Reports, BMO Capital Markets, Bloomberg

Ontario and B.C. Contracted Plants

This group of assets includes renewable energy facilities that earn revenue pursuant to power purchase agreements with government counterparties. Capital Power owns two hydroelectric facilities in B.C. with an aggregate capacity of 40 MW and a 40 MW wind farm in Ontario. Output from these facilities is sold pursuant to long-term contracts with BC Hydro and the Ontario Power Authority, respectively. In addition, this group includes the 275 MW natural gas-fired Island Generation facility acquired from Kelson Canada Inc. in October of 2010 for a purchase price of approximately $205 million ($745/kW). The facility, which is located in Campbell River, British Columbia, is fully contracted from April 1, 2010, to April 2022 under a tolling arrangement with BC Hydro, under which BC Hydro is responsible for the fuel supply. Capital Power plans to sell its two small-scale hydro facilities in mid-2012, consistent with its strategy to no longer pursue hydro and biomass projects.

Northeast U.S. Commercial Facilities

During 2011, Capital Power announced the acquisition of three natural gas-fired power generation facilities with an aggregate capacity of 1,089 MW. The facilities include a power plant located in Tiverton, Rhode Island, a second plant located in Rumford, Maine, and a third facility located in Bridgeport, Connecticut. The assets sell electricity into the NEPOOL market and are exempt wholesale generators with federal energy regulatory commission authority to sell capacity, energy and ancillary services at market-based rates. The Bridgeport acquisition, which followed the purchase of the Rumford and Tiverton power plants, helped Capital Power establish a "networked hub" in the New England region.

North Carolina Contracted Facilities

In connection with an acquisition by Atlantic Power Corp. (ATP-TSX, not rated), Capital Power Income LP agreed to divest its North Carolina assets, which included the 103 MW Southport and 52 MW Roxboro facilities, to Capital Power Corp. for approximately $121 million. These facilities have recently undergone an $87 million enhancement project, reducing environmental emissions and improving economic performance. With their current fuel mix, the operations produce up to 134 MW of power, and have a nameplate capacity of 155 MW. Southport and Roxboro are under long-term contract with Progress Energy to 2021.

Power Purchase Arrangements

In addition to owning power generation facilities subject to Alberta PPAs, Capital Power also owns the PPA contracts for 52% of the aggregate capacity from units 5 and 6 of the Sundance facility. TransAlta Corporation is the owner of the physical Sundance asset. Capital Power is obligated to purchase its pro rata share of output generated from Sundance 5 and 6 at prices governed by the Sundance PPA. Capital Power uses this electricity for portfolio optimization purposes, such as physically hedging the output of its committed capacity or selling the power either directly into the spot market or entering into forward sales agreements with creditworthy counterparties.

Growth Initiatives Support Significant EBITDA Upside

In addition to owning and managing existing power generation, Capital Power is actively involved in greenfield development. Capital Power's current construction and late-stage development pipeline includes the facilities set out in Table 15.

Table 15: *Capital Power – Development Pipeline*

Facility	Location	Fuel Type	Ownership Interest (%)	Gross Capacity (MW)	Net Capacity (MW)	Electricity Purchaser	Expected In-Service Date	Est. Capital Cost ($mm) - 100%	Est. Capital Cost ($mm) - Net to CPX
Quality Wind	BC	Wind	100.0%	142.0	142.0	BC Hydro	Q4/2012	455.0	455.0
Halkirk Wind Project	AB	Wind	100.0%	150.0	150.0	Merchant (2)	Q4/2012	357.0	357.0
Port Dover & Nanticoke Wind Project	ON	Wind	100.0%	105.0	105.0	OPA	Q4/2013	340.0	340.0
K2 Wind Project	ON	Wind	33.3%	270.0	89.9	OPA	2014	874.0	291.0 (3)
Total				**667.0**	**486.9**			**2,026.0**	**1,443.0**

Notes:
(1) OPA = Ontario Power Authority
(2) Capital Power will sell Renewable Energy Certificates (RECs) to Pacific Gas and Electric Company under the terms of a 20-year fixed-price agreement.
(3) Capital Power's net obligation for the K2 Wind capital costs amount to $46 million. The balance of proceeds will come from project financing and partners.
Source: BMO Capital Markets, Company Reports

Quality Wind

Quality Wind is a 142 MW wind project located near Tumbler Ridge, B.C. which was awarded a 25-year electricity purchase agreement from BC Hydro pursuant to BC Hydro's 2008 Clean Power Call. Capital costs are expected to be approximately $455 million ($3,204/kW) and the facility is expected to achieve commercial operation by the end of 2012.

Halkirk Wind

Halkirk Wind is a 150 MW wind farm development located in central Alberta with a 20-year fixed price sales arrangement for the renewable energy certificates with Pacific Gas and Electric Company. Halkirk's energy output will be sold into the deregulated wholesale electricity market and will be managed as part of Capital Power's Alberta electricity portfolio optimization activities. Commercial operation is expected in the last quarter of 2012 at a cost of approximately $357 million ($2,380/kW).

Port Dover and Nanticoke Wind Project

The Port Dover and Nanticoke Wind Project is a proposed 105 MW wind farm located in southern Ontario. On April 8, 2010, the project was awarded a 20-year power purchase agreement by the Ontario Power Authority under the Feed-in Tariff program. The project, which has an expected capital cost of approximately $340 million ($3,239/kW), is expected to enter commercial operation by the fourth quarter of 2013.

K2 Wind Power Project

The K2 wind power project is a proposed 270 MW wind farm located in southwestern Ontario. The project has an expected total capital cost of $874 million, most of which will be funded through project financing. K2 will have a 20-year PPA with the OPA and completion of the project is subject to regulatory approvals. It is expected that construction will begin in 2013, with commercial operation in 2014. At commencement of commercial operation, each of the three partners (Capital Power, Samsung Renewable Energy Inc. and Pattern Renewable Holdings Canada ULC) will have an equal economic interest in the project.

Earnings Estimates

We are introducing the following estimates for 2012 and 2013.

Table 16: *Capital Power Estimates*

	2012E	2013E
Revenue	**1,372.1**	**1,451.5**
Energy Purchases and Fuel	577.8	580.9
Gross Margin	**794.3**	**870.6**
% of revenue	57.9%	60.0%
EBITDA (Excluding Mark-to-Market Items)	**497.4**	**560.5**
% of revenue	36.2%	38.6%
Net Earnings Attributable to Common Shareholders	**95.5**	**112.8**
% of revenue	7.0%	7.8%
Average shares o/s (basic)	66.4	68.7
Average shares o/s (diluted)	97.2	97.2
EPS (basic & diluted)	**$1.44**	**$1.64**
First Call Consensus	***$1.49***	***$1.75***
CFPS (basic & diluted)	**$4.00**	**$4.50**

Source: BMO Capital Markets, Thomson ONE

Valuation – Target Price $26

We value Capital Power shares using a target EV/EBITDA multiple and support this valuation with secondary measures. For Capital Power, our $26 price target is based on 8.5x 2013E EV/EBITDA, which is consistent with the target we use for its closest peer, TransAlta, and a discount to the contracted IPPs given CPX's exposure to merchant power prices. Our target price implies a yield of 4.9% and 15.6x our 2013 earnings estimate.

Although we use a multiple of EBITDA as our dominant approach to value CPX shares, there are a number of secondary measures we use to support our valuation:

- Discounted Cash Flow: Our discounted cash flow analysis produces a ~$26.50 price objective on a fully diluted basis. Our key assumptions include a weighted average cost of capital of 7.6%, which is determined by appropriate weights of debt, preferred shares, and equity that make up the company's capital structure. Our terminal value is based on 2015 cash flow, priced as an annuity, using our weighted average cost of capital and a growth rate of 1%. We assume a recurring Alberta merchant power price of $70/MWh and ongoing capital expenditures that are equal to CPX's estimated depreciation in 2015.

Table 17: *Discounted Cash Flow Supports Valuation*

		2012E	2013E	2014E	2015E
Operating Cash Flow		400.2	449.2	499.2	502.5
Less: Incremental Tax Associated with CPLP NCI		(11.4)	(12.2)	(20.9)	(21.2)
Operating Cash Flow Allocable to CPLP		**388.8**	**437.0**	**478.4**	**481.4**
Less: Capital Expenditures		(696.0)	(313.4)	(76.9)	(76.9)
Add: After-Tax Interest Expense		64.1	63.4	57.7	57.4
Undiscounted Cash Flow		**(243.0)**	**187.1**	**459.2**	**462.0**
Terminal Cash Flow					**4,702.3**
Discount Factor		0.930	0.864	0.804	0.747
Discounted Cash Flow		**(225.9)**	**161.7**	**369.0**	**3,857.7**
Terminal Value					
Discounted Cash Flow	4,162.4				
Less: CPLP Net Debt Outstanding	(1,407.0)				
Less: Preferred Shares	(122.0)				
Less: Decommissioning	(230.0)				
Net Present Value	**2,403.4**				
Diluted Shares Outstanding	90.5				
NPV/Share	**$26.55**				

Weighted Average Cost of Capital	**Pre-tax Cost**	**Weight**	**After-Tax Cost**	**WACC**
Debt	6.00%	50.00%	4.32%	2.2%
Preferred Equity	4.60%	5.00%	4.60%	0.2%
Equity	11.50%	45.00%	11.50%	5.2%
				7.6%
Growth Rate				1.0%
Terminal Value				**4,702.3**
Terminal Value Power Price				**$70.00**

Source: BMO Capital Markets

Table 18: *Target Price Sensitivity to Cost of Equity and Terminal Power Price*

		Terminal Value Power Price ($/MWh)						
		$55.00	**$60.00**	**$65.00**	**$70.00**	**$75.00**	**$80.00**	**$85.00**
Discount Rate	**9.5%**	$21.91	$26.11	$30.30	$34.50	$38.69	$42.89	$47.08
	10.0%	$20.25	$24.26	$28.27	$32.28	$36.29	$40.30	$44.31
	10.5%	$18.72	$22.56	$26.39	$30.23	$34.07	$37.91	$41.75
	11.0%	$17.29	$20.97	$24.65	$28.33	$32.01	$35.68	$39.36
	11.5%	$15.96	$19.49	$23.02	**$26.55**	$30.08	$33.61	$37.14
	12.0%	$14.72	$18.11	$21.50	$24.89	$28.29	$31.68	$35.07
	12.5%	$13.55	$16.82	$20.08	$23.34	$26.61	$29.87	$33.13
	13.0%	$12.46	$15.60	$18.75	$21.89	$25.03	$28.17	$31.31
	13.5%	$11.44	$14.46	$17.49	$20.52	$23.55	$26.58	$29.61

Source: BMO Capital Markets

• Sum of the Parts: As shown in Table 19, our sum-of-the-parts analysis generates ~$26 per share, based on best indications of representative publicly traded companies and transactions as applied to our 2013 outlook.

Table 19: *Capital Power Sum-of-the-Parts Valuation*

	2013E EBITDA	EV/EBITDA Multiple	Implied Enterprise Value
Alberta Contracted Facilities	157.4	8.25x	1,298.3
Alberta Commercial Facilities	323.5	8.00x	2,587.7
Ontario & BC Contracted Facilities	81.0	10.00x	810.2
Northeast U.S. Commercial Facilities	51.0	8.00x	408.3
North Carolina Contracted Facilities	15.0	8.00x	120.0
Corporate Costs	(52.4)	9.00x	(471.6)
Long-term debt			(1,856.3)
Decommissioning Costs			(230.0)
Preferred shares			(125.0)
			2,541.7
2013E diluted shares o/s			97.2
2013E NAV/Share			**$26.15**

Source: BMO Capital Markets

• Peer Group: CPX is currently trading at 8.4x 2013E EV/EBITDA. This is a slight premium to its closest peer, TransAlta.

Table 20: *Peer Group Valuation Table*

	Ticker	Price 05-Apr-12	High 52 Wk	Low 52 Wk	12-Month Target	ROR Target	Rating (1)	Shares O/S (mm)	Market Cap. (mm)	EPS 2010A	EPS 2011E	EPS 2012E	EPS 2013E	CAGR ('11-'13)	P/E 2010A	P/E 2011A	P/E 2012E	P/E 2013E	EV/EBITDA 2013E	Dividend Rate (4)	Dividend Yield
Utilities																					
ATCO Ltd. (2)	ACO/X	$70.35	$71.50	$55.34	NA	NA	NR	57.7	$4,061.3	$5.04	$5.70	$6.22	$6.41	6.0%	10.1	10.6	11.3	11.0	NA	$1.31	1.9%
Canadian Utilities Ltd.	CU	$66.12	$68.12	$51.54	$70.00	8.5%	OP	127.6	$8,438.1	$3.32	$3.63	$4.03	$4.13	6.5%	14.2	15.6	16.4	16.0	10.0	$1.77	2.7%
Caribbean Utilities (3)	CUP.U	$9.95	$10.49	$9.01	$9.50	2.1%	Und	28.6	$284.8	$0.67	$0.67	$0.67	$0.70	2.0%	13.0	13.9	14.9	14.3	10.6	$0.66	6.6%
Emera Inc.	EMA	$33.75	$34.92	$19.95	$34.00	4.7%	Mkt	122.2	$4,125.4	$1.65	$1.65	$1.72	$1.84	5.7%	16.1	19.3	19.6	18.3	13.2	$1.35	4.0%
Fortis Inc.	FTS	$32.11	$34.39	$28.24	$34.50	11.2%	OP	188.8	$6,063.8	$1.60	$1.66	$1.74	$1.81	4.4%	18.4	19.7	18.5	17.8	10.6	$1.20	3.7%
Average						**6.6%**								**4.9%**	**14.4**	**15.8**	**16.1**	**15.5**	**11.1**		**3.8%**
Power																					
Boralex Inc.	BLX	$8.00	$9.00	$5.85	$9.00	12.5%	Mkt	37.7	$301.8	($0.15)	($0.07)	($0.07)	($0.29)	nmf	nmf	nmf	nmf	nmf	14.5	$0.00	0.0%
Capital Power Corp.	CPX	$23.40	$28.00	$21.50	$26.00	16.5%	OP	97.2	$2,274.1	$1.40	$1.24	$1.44	$1.64	14.9%	16.3	20.1	16.3	14.3	8.4	$1.26	5.4%
TransAlta Corp.	TA	$18.12	$23.42	$18.25	$19.00	11.3%	Mkt	224.6	$4,070.0	$0.88	$1.04	$1.12	$1.15	5.3%	24.5	20.5	16.1	15.8	8.0	$1.16	6.4%
Average						**13.4%**								**10.1%**	**20.4**	**20.3**	**16.2**	**15.0**	**10.3**		**3.9%**

Notes:
(1) Ratings Key: Outperform – OP; Market Perform – Mkt; Underperform – Und.; Not Rated – NR; Restricted - R
(2) Estimates per First Call
(3) All figures in US Dollars
(4) Recent dividend/distribution annualized
Source: BMO Capital Markets, Thomson One

Investment Risks

Capital Power shares are subject to the following risks:

- **Equity Overhang Risk**: Any sale of the remaining ~29% of Capital Power that EPCOR owns or the perception that such sales could occur could adversely affect prevailing market prices for Capital Power's common shares and impede the corporation's ability to raise capital through the issuance of additional equity.
- **Operating Risk**: The generation of electricity is a highly mechanical process. All of the company's facilities must be properly maintained if they are to operate in a manner that is consistent with our estimates.
- **Commodity Price Risk**: Capital Power has the following direct exposures to commodity prices: (1) the energy trading division and many of its facilities sell power into the Alberta Power Pool, which exposes the company's revenue to fluctuations in merchant electricity prices; and (2) to the extent that its facilities have not secured fixed price contracts, the company is exposed to fluctuating fuel prices. Although Capital Power attempts to mitigate these risks through hedging, changes in spot electricity and natural gas prices have the potential to affect the profitability of the company's merchant facilities.
- **Fuel Supply Risk**: The company requires energy from sources such as natural gas, coal, waste heat, water and wind to generate electricity. A disruption in the supply or a significant increase in the price of any fuel required by Capital Power could have a material adverse impact on Capital Power's business, financial condition and results of operation.
- **Environmental Risk**: Many of the company's operations are subject to extensive environmental laws and regulatory guidelines. Compliance with new and existing regulatory requirements may require Capital Power to incur significant capital expenditures and/or additional operating expenses, and failure to comply with such regulations could result in fines, penalties or the forced curtailment of operations.
- **Foreign Exchange Risk**: CPX reports in Canadian dollars, but also owns facilities in the United States. Changes in foreign exchange rates will affect the profitability and cash flow of Capital Power.

Capital Power's Management Team

Table 21: Management Overview

Name	Position	Employment History
Brian Vaasjo	President and Chief Executive Officer	- President & CEO of Capital Power since 2009 IPO. - Appointed Chief Operating Officer of EPCOR in 2008. - Formerly President of CPILP since its acquisition in 2005. - Joined EPCOR in 1998 as Executive Vice President and Chief Financial Officer. - Spent 19 years with the Enbridge Group of Companies.
Stuart Lee	Senior VP - Finance & Chief Financial Officer	- Joined EPCOR in 2003 as Vice President & Corporate Controller. Served as CFO of CPILP since it was acquired in 2005. - Prior to joining EPCOR, Mr. Lee was VP & Controller of Celanese Canada Inc., a large petrochemical manufacturer, for five years. - Mr. Lee is also Chartered Accountant who articled with a large international accounting firm.
James Oosterbaan	Senior VP - Operations & Commodity Portfolio Management	- Appointed to role in January 2011. - Previously Senior Vice President Commercial Services at EPCOR. - Prior to joining EPCOR, Mr. Oosterbaan was a consultant in the energy and information technology sector and was employed with the Westcoast Energy Group of Companies.
Kathryn Chisolm	Senior VP - Legal, Regulatory & Governmental Affairs	- Previously served as EPCOR's Senior VP, General Counsel & Corporate Secretary directing all legal and environmental affairs for EPCOR, CPILP and their subsidiaries.
Darcy Trufyn	Senior VP - Construction & Engineering	- Joined Capital Power in 2009. - Formerly Senior Vice President Construction with Worley Parsons in Calgary where he was responsible for all Canadian construction activities. - Also formerly President of the construction firm Lockerbie & Hole, based in Edmonton.
Brian DeNeve	Senior VP - Commercial Services	- Prior to being appointed to this role in 2011, Mr. DeNeve was VP, Business Development, where he led the development of Clover Bar Energy Centre, development of several wind projects in Canada, and the acquisition of the Island Generation facility in British Columbia. - Prior to joining EPCOR in 1996, Mr. DeNeve was with the Alberta Department of Energy, where he participated in the development and implementation of the deregulated electricity market in Alberta.

Source: Company reports

Table 22: *Consolidated Summary Sheet*

	H2/2009	2010	2011	2012E	2013E	CAGR 2011A-2013E
Total EPS (GAAP Basic)	$0.97	$0.50	$1.60	$1.44	$1.64	
Total EPS (Normalized Basic)	**$0.60**	**$1.40**	**$1.24**	**$1.44**	**$1.64**	14.9%
Total EPS (GAAP Diluted)	$0.89	$0.50	$1.59	$1.44	$1.64	
First Call Consensus				*$1.49*	*$1.75*	
CPS (Diluted)	$1.85	$4.41	$4.26	$4.00	$4.50	
Dividends	$0.63	$1.26	$1.26	$1.26	$1.26	0.0%
Payout Ratio	70.5%	254.2%	79.2%	87.5%	76.8%	
Average Shares Outstanding (basic mm)	21.8	22.2	44.3	66.4	68.7	
Average Shares Outstanding (diluted mm)	78.4	78.4	90.5	97.2	97.2	
Book Value per Share	$22.48	$22.66	$23.71	$20.59	$21.06	
Market Valuation						
Price: High	$23.00	$18.88	$27.06	-	-	
Price: Low	$19.08	$15.38	$21.62	-	-	
Price: Current	-	-	-	$23.40	-	
P/E Ratio: High	nmf	13.5	21.8	-	-	
P/E Ratio: Low	nmf	11.0	17.4	-	-	
P/E Ratio: Current	-	-	-	16.3	14.3	
EV/EBITDA: High	nmf	11.9	13.7	-	-	
EV/EBITDA: Low	nmf	11.1	12.4	-	-	
EV/EBITDA: Current	-	-	-	9.3	8.4	
Yield: High Price	5.5%	6.7%	4.7%	-	-	
Yield: Low Price	6.6%	8.2%	5.8%	-	-	
Yield: Current	-	-	-	5.4%	5.4%	
Balance Sheet ($mm)						
Debt (S-T)	247.0	235.0	28.0	121.0	108.3	
Debt (L-T)	1,472.0	1,634.0	1,457.0	1,748.0	1,748.0	
Minority Interest	2,064.0	1,754.0	1,072.0	1,090.1	1,115.5	
Preferred Shares	0.0	125.0	125.0	125.0	125.0	
Shareholders' Equity	489.0	702.0	1,398.0	1,415.7	1,447.6	
	4,272.0	4,450.0	4,080.0	4,499.8	4,544.4	
Balance Sheet (%)						
Debt (S-T)	5.8%	5.3%	0.7%	2.7%	2.4%	
Debt (L-T)	34.5%	36.7%	35.7%	38.8%	38.5%	
Minority Interest	48.3%	39.4%	26.3%	24.2%	24.5%	
Preferred Shares	0.0%	2.8%	3.1%	2.8%	2.8%	
Shareholders' Equity	11.4%	15.8%	34.3%	31.5%	31.9%	
	100.0%	100.0%	100.0%	100.0%	100.0%	
Income & Cash Flow Metrics ($mm)						
Total Revenue	1,008.0	1,760.0	1,770.0	1,372.1	1,451.5	-9.4%
EBITDA Composition						
Alberta Contracted EBITDA	74.0	156.0	190.0	164.6	157.4	-9.0%
Alberta Commercial EBITDA	80.0	196.0	224.0	298.0	323.5	20.2%
ON & BC Contracted EBITDA	6.0	16.0	38.0	35.8	81.0	46.0%
New England Commercial EBITDA	0.0	0.0	26.0	50.4	51.0	40.1%
Other EBITDA	6.0	3.0	8.0	8.0	8.0	0.0%
CPILP EBITDA	95.3	177.2	150.8	0.0	0.0	
Corporate Costs (Incl. Unrealized Gains/Losses)	(2.3)	(161.2)	(151.8)	(59.4)	(60.4)	
EBITDA	**259.0**	**387.0**	**485.0**	**497.4**	**560.5**	7.5%
EBITDA (Excluding Mark-to-Market Items)	**322.0**	**357.0**	**437.0**	**497.4**	**560.5**	13.3%
Depreciation, Minority Interest & Other Costs						
Net Earnings	**21.0**	**11.0**	**71.0**	**95.5**	**112.8**	
Cash Flow from Operations	**174.0**	**354.0**	**402.0**	**400.2**	**449.2**	5.7%

Note: Priced as of market close on April 5, 2012.
Source: BMO Capital Markets, Company Reports

Canadian Utilities Limited

Initiating Coverage at Outperform; Utility Business to Drive Growth

Canadian Utilities (CU-TSX)
Price: $66.12 (Apr-5-12)
Target: $70.00

Investment Summary

- **We are initiating coverage of Canadian Utilities Limited with an Outperform rating and a $70 target price.** In our view, the company owns a well-diversified portfolio of regulated utility, power and midstream assets in one of Canada's most attractive energy basins, with a demonstrated commitment to an A-rated balance sheet, a solid management team and a clearly defined, manageable capital program. Our target price of $70 represents a 17x 2013E EPS, which is a discount to its peer group but at the upper end of its five-year historical trading range. We believe the upper end of the range is justified given an improvement in earnings quality and visibility (utility operations is expected to increase to ~66% of earnings in 2013 vs. ~54% in 2011, with the possibility of ~77% regulated utility exposure by 2015) and the secular reduction observed in 10-year government of Canada bond yields.

- **Where rubber hits the road.** Despite the fact that Canadian Utilities Limited is currently a diversified energy utility with operations not only in regulated utilities but also in midstream and power, the rubber hits the road when it comes to its utility business, particularly in electric transmission infrastructure. As illustrated in Table 23, during our forecast period we expect ATCO Electric Transmission to grow by 34.9%, ATCO Electric Distribution by 22.0% and ATCO Gas by 12.2%. This should support a two-year earnings CAGR of 6.5% through 2013, with associated dividend growth of 7.6% (vs. a five-year average of 7.0%). We note that this growth comes largely from organic opportunities within its regulated utility businesses.

Table 23: *Rate Base Growth 2007-2013E*

	2007	2008	2009	2010	2011	2012E	2013E	CAGR 2011A-2013E
ATCO Gas (North & South)								
Average Utility Rate Base ($mm)	$1,108.6	$1,229.8	$1,386.6	$1,410.0	$1,524.0	$1,745.7	$1,918.7	**12.2%**
Annual Growth Rate		10.9%	12.8%	1.7%	8.1%	14.5%	9.9%	
ATCO Electric (Transmission)								
Average Utility Rate Base ($mm)	$879.7	$923.2	$965.0	$1,275.0	$1,940.0	$3,009.2	$3,528.1	**34.9%**
Annual Growth Rate		4.9%	4.5%	32.1%	52.2%	55.1%	17.2%	
ATCO Electric (Distribution)								
Average Utility Rate Base ($mm)	$1,009.6	$1,155.1	$973.1	$1,104.3	$1,193.0	$1,429.3	$1,777.1	**22.0%**
Annual Growth Rate		14.4%	-15.8%	13.5%	8.0%	19.8%	24.3%	
ATCO Pipelines (North & South)								
Average Utility Rate Base ($mm)	$706.2	$711.1	$746.0	$759.0	$825.0	$870.2	$915.9	**5.4%**
Annual Growth Rate		0.7%	4.9%	1.7%	4.9%	9.3%	5.3%	

Source: BMO Capital Markets, Company Reports

- **Financial strength.** Canadian Utilities' success in meeting our EPS target is predicated on execution of a ~$6 billion capital plan from 2012 to 2014, which has more to do with the continued support of the Alberta government and regulatory approval than the company's financial capabilities. Indeed, CU's financial position is something that is increasingly catching our eye. Canadian Utilities' generated $1.3 billion ($10.60 per share) in cash flow during 2011 and ended the year with a net debt-to-capital ratio of 49.5%. While the company's priorities for its cash flow are to fund its growth initiatives, we believe dividend growth will still continue (annual increases since 1972). Canadian Utilities also has an annual stock buyback program to purchase up to 3% of Class A shares, although we note that the company repurchased only 12,767 shares in last year's program, which is not surprising given the company's current growth prospects.

- **Low payout ratio should support significant dividend growth upside.** Of all the utilities in our coverage universe, Canadian Utilities has the lowest payout ratio. In 2011, the payout ratio was roughly 45% and has been around that level over the last few years. The low payout ratio is currently warranted at this time given the company's 47% exposure to non-regulated businesses, which have less earnings visibility and cash flow stability. We believe that with the successful execution of its planned utility infrastructure spending, the company has and will potentially have successfully improved the quality of its earnings stream, attracting additional shareholder interest and improving its ability to increase its dividend payout ratio to the 50–55% range. Our view of where the payout ratio will go is still below the typical energy utility peer group range of 60–70%.

- **Key growth projects on track.** Canadian Utilities' $1.6 billion, 500kV HVDC Eastern Alberta Transmission Line is now back on track for an expected in-service date of late 2014, following a period of uncertainty when the Government of Alberta requested the regulatory process be adjourned as it wanted to reexamine its approach to certain critical transmission infrastructure projects. On February 23, 2012, the Government of Alberta directed the Eastern Line to proceed following a recommendation from an independent expert panel that there is a need for the line to proceed as soon as possible. In terms of CU's other major growth initiatives, the $765 million Hanna transmission project is also charging forward and on track for start-up at the end of the second quarter of 2013. Hanna consists of six different projects comprising roughly 380 km of transmission lines, the construction of nine new substations and expansion to a further 14 existing substations.

- **Most significant earnings risk: lower allowed ROEs.** Although the methodologies used to calculate return on equity allowed by the Alberta Utilities Commission are no longer largely driven by a forecast of the 30-year government of Canada bond yield for the prospective fiscal period, we are mindful that the allowed ROE is subject to periodic review and adjustments, particularly in light of the systematic reduction in government bond yields. For example, late last year, the Alberta Utilities Commission lowered the ROE to 8.75% from 9.00%. The earnings contribution from Canadian Utilities' regulated utility operations could be negatively affected by lower allowed returns on equity.

Table 24: *Sensitivity of Earnings per Share to Change in Regulated Metrics*

	2012E	2013E
ATCO Gas (North & South)		
100 bps Change in ROE	$0.05	$0.06
100 bps Change in Deemed Equity	$0.01	$0.01
5.00% Change in Rate Base	$0.02	$0.02
ATCO Electric (Transmission)		
100 bps Change in ROE	$0.09	$0.10
100 bps Change in Deemed Equity	$0.02	$0.02
5.00% Change in Rate Base	$0.04	$0.04
ATCO Electric (Distribution)		
100 bps Change in ROE	$0.04	$0.05
100 bps Change in Deemed Equity	$0.01	$0.01
5.00% Change in Rate Base	$0.02	$0.02
ATCO Pipelines (North & South)		
100 bps Change in ROE	$0.03	$0.03
100 bps Change in Deemed Equity	$0.01	$0.01
5.00% Change in Rate Base	$0.01	$0.01

Source: BMO Capital Markets

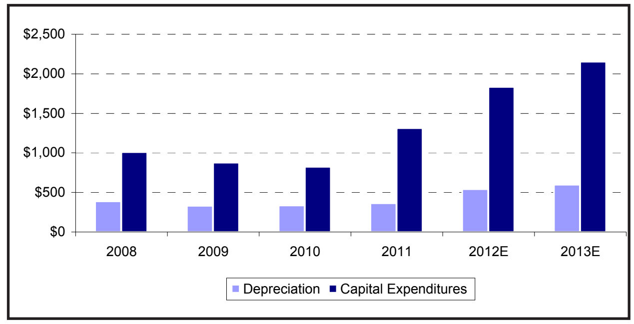
- **Earnings estimates.** We are introducing EPS forecasts of $4.03 in 2012 and $4.13 in 2013.
- **Relative valuation.** At current levels, CU is trading at a P/E of 16.4x in 2012E (vs. 16.1x for our Canadian utility peer group) and 16.0x in 2013E (vs. the group average at 15.5x).

Exhibit 26: *Canadian Utilities Limited at a Glance*

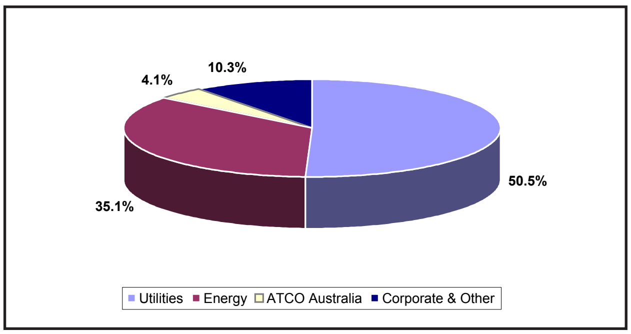
Upcoming Events/Potential Catalysts

April 2012	AESO 10-Year Transmission Plan
April 23, 2012	Government of Alberta Election
April 2012	ATCO Gas Australia - hearing to appeal calculation of rate of return
Late May 2012	ATCO Gas Australia - expected decision regarding the April appeal
April 2012	Q1/12 Results
May 3, 2012	Annual General Meeting
Q2 2012	Expected regulatory approval of remaining Hanna projects
Summer 2012	Final Federal environmental rules for coal-fired generation
July 2012	Q2/12 Results
October 2012	Q3/12 Results
Late 2012	Expected regulatory approval of Eastern Alberta Transmission Line
2013	Battle River 3/4 PPA contracts expire
Q2/13	Expected in-service of Hanna transmission projects
Early 2015	Expected in-service of Eastern Alberta Transmission Line

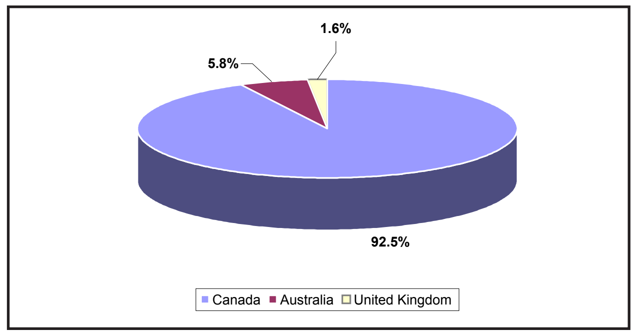
Significant Capital Investment Program Ahead ($mm)



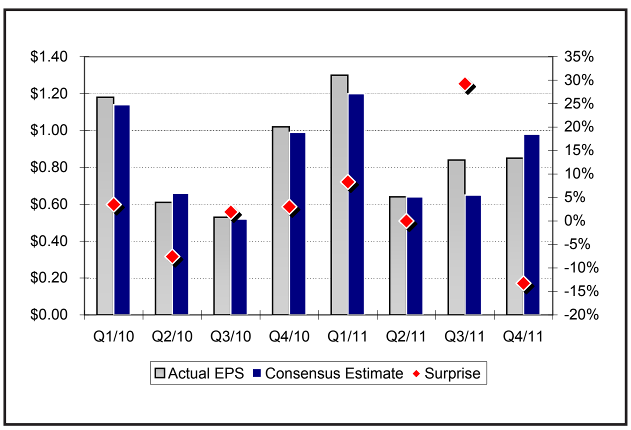
2011 Adjusted Earnings by Segment



2011 Revenue by Geography

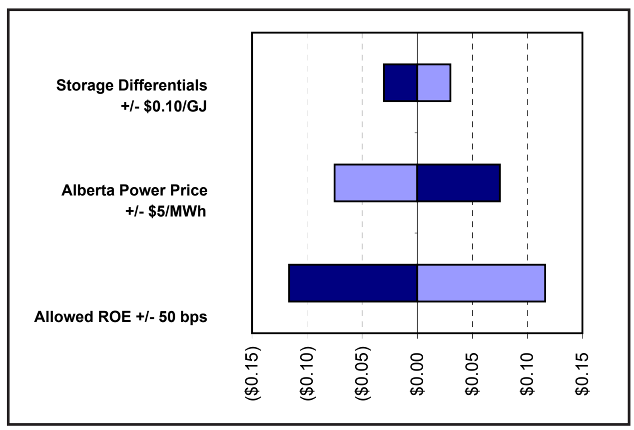


EPS Surprises vs. Consensus



Source: Company Reports, Thomson One

Sensitivities



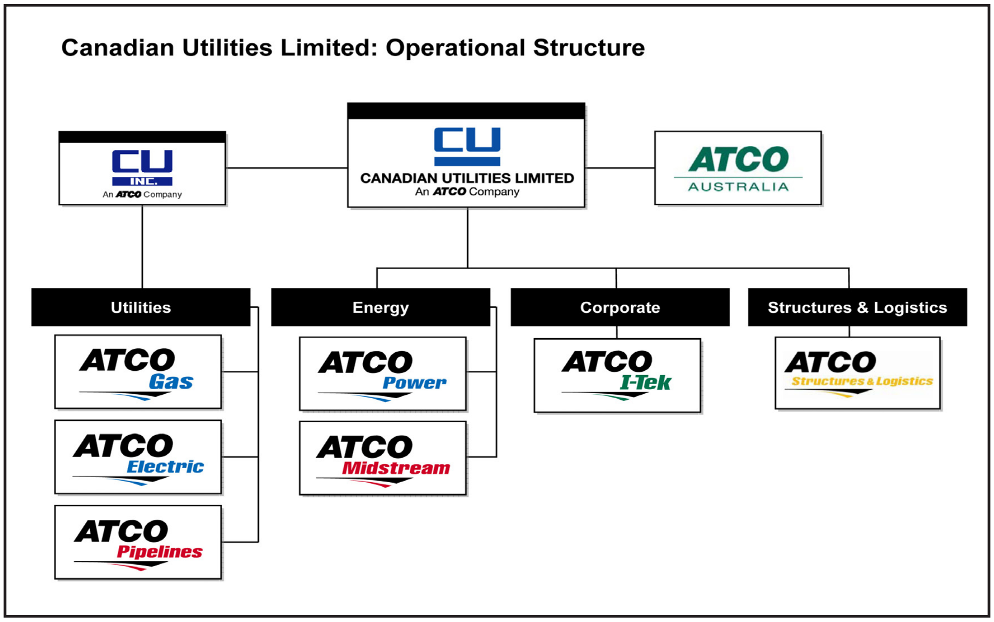
Source: BMO Capital Markets

Source: BMO Capital Markets, Company Reports

Corporate Overview

The company has four key business segments: (1) Utilities; (2) Energy; (3) ATCO Australia; and (4) Corporate & Other.

***Exhibit 27:** Simplified Corporate Structure*



Source: Company Reports

***Table 25:** 2011 CU Ltd. Segmented Information (Excluding Intersegment Eliminations)*

	Adjusted Earnings	% of Total	Total Assets	% of Total	Gross Capex	% of Total
Utilities	236.0	50.5%	7,903.0	66.6%	1,316.0	94.4%
Energy	164.0	35.1%	1,891.0	15.9%	33.0	2.4%
ATCO Australia	19.0	4.1%	1,340.0	11.3%	23.0	1.6%
Corporate & Other (1)	48.0	10.3%	728.0	6.1%	22.0	1.6%
Total	**467.0**	**100.0%**	**11,862.0**	**100.0%**	**1,394.0**	**100.0%**

Note: (1) Includes equity income from ATCO Structures & Logistics.
Source: Company Reports, BMO Capital Markets

1. Utilities

Canadian Utilities' core business is the regulated transmission and distribution of natural gas and electricity. This segment serves more than 1.3 million customers primarily in Alberta and also in the Canadian North. The Utilities segment includes ATCO Electric, ATCO Gas and ATCO Pipelines.

ATCO Electric

ATCO Electric is a regulated business engaged in the transmission and distribution of electricity to 245 communities as well as rural areas in east-central and northern Alberta, 19 communities in the Yukon Territory and nine communities in the Northwest Territories. The system consists of 10,000 km of main transmission lines and 64,000 km of distribution lines. In addition, ATCO Electric also delivers power to and operates 10,000 km of REA-owned distribution lines.

As illustrated in Table 26, CU's customer base is dominated by industrial and commercial electric power users, and we do not expect this customer mix to change materially over time.

***Table 26:** Electricity Sales by Customer Class - 2010-2011*

	2011		2010	
	GWh	**%**	**GWh**	**%**
Industrial	6,557.0	61.9%	6,630.0	63.0%
Commercial	2,237.0	21.1%	2,156.0	20.5%
Residential	1,289.0	12.2%	1,239.0	11.8%
Rural, REAs and other	513.0	4.8%	507.0	4.8%
	10,596.0	**100.0%**	**10,532.0**	**100.0%**

Source: Company Reports

ATCO Gas

ATCO Gas is a regulated business engaged in the distribution of natural gas throughout Alberta and in the Lloydminster area of Saskatchewan. ATCO Gas serves more than one million customers in nearly 300 communities and owns and operates more than 38,000 km of distribution mains in addition to owning service and maintenance facilities in major centres in Alberta.

***Table 27:** Natural Gas Distributed by Customer Class - 2010-2011*

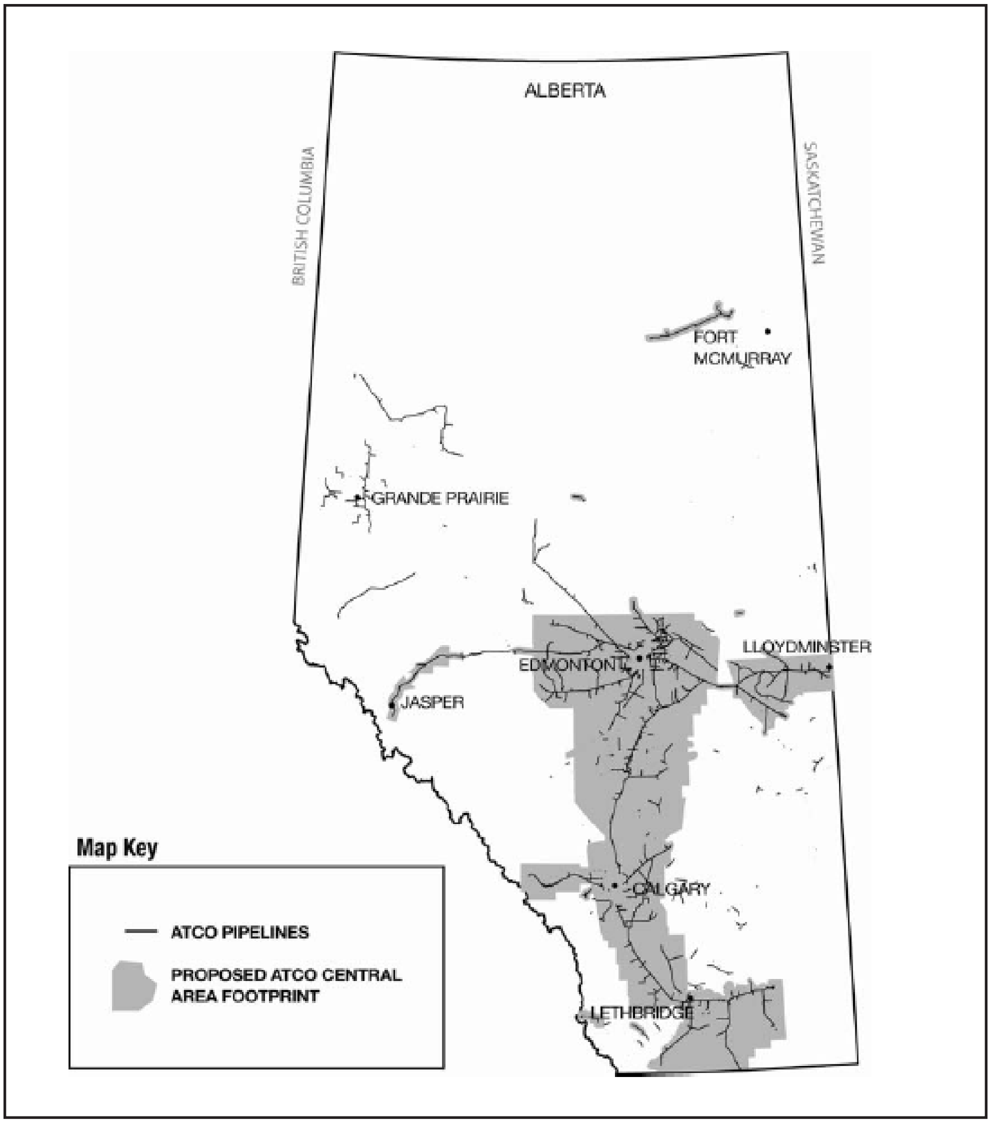
	2011		2010	
	PJ	**%**	**PJ**	**%**
Residential	119.7	48.4%	115.5	48.7%
Commercial	113.4	45.9%	107.9	45.5%
Industrial	14.0	5.7%	13.9	5.9%
Other	0.2	0.1%	0.1	0.0%
	247.3	**100.0%**	**237.4**	**100.0%**

Note: PJ = Petajoule
Source: Company Reports

ATCO Pipelines

ATCO Pipelines is a regulated business engaged in the transmission of natural gas in Alberta which provides natural gas transportation services to producers, major industrial users and gas distribution companies in Alberta. The system, which has a peak delivery capacity of 3.8 bcf/d, currently consists of approximately 8,500 km of pipelines, 22 compressor sites, approximately 4,104 receipt and delivery points, and a salt cavern storage peaking facility located near Fort Saskatchewan, Alberta.

Exhibit 28: *ATCO Pipelines – Franchise Area*



Source: Company Reports

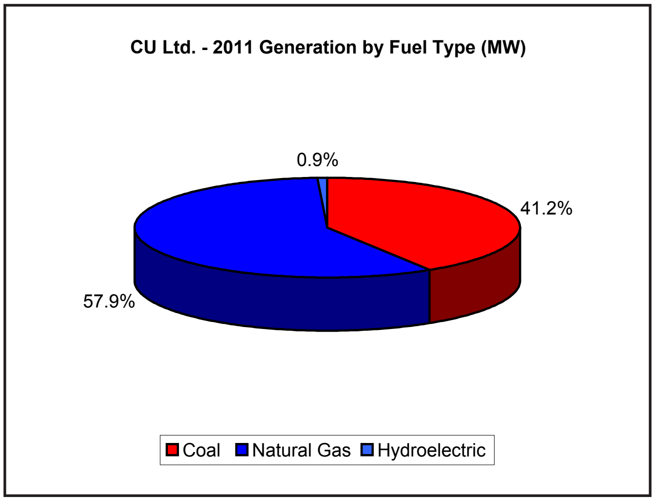
2. Energy

This segment owns and operates both regulated and non-regulated generating plants, including coal, natural gas-fired and hydroelectric generating plants in the U.K. and Canada under the ATCO Power entity. ATCO Midstream is involved in non-regulated natural gas gathering, processing, storage and NGL extraction.

ATCO Power

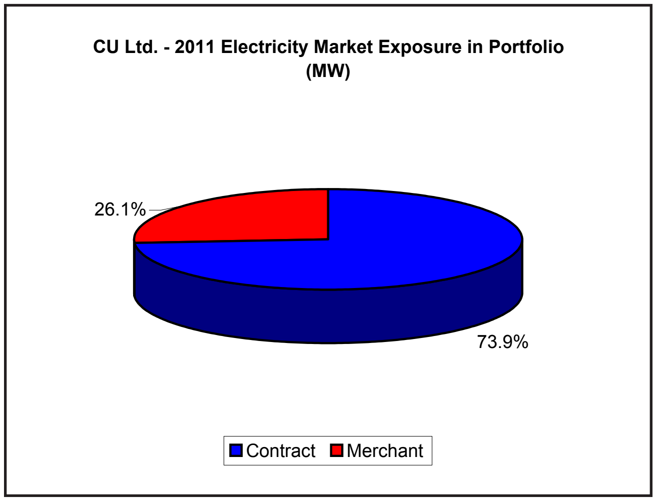
ATCO Power is in the business of owning, operating and developing power generation facilities in the U.K. and Canada. As at December 31, 2011, ATCO Power had an ownership interest in 16 power plants with a total capacity of 4,590 MW. ATCO Power operates 4,470 MW of this capacity and has a net ownership interest of 2,550 MW. Of this net capacity, ATCO Power has 665 MW or approximately 26% of its generating capacity exposed to merchant electricity markets in Alberta and the U.K. We note that these merchant facilities are significantly influenced by generating plant availability, spark spreads and volatility in electricity markets.

Exhibit 29: *Generation Capacity by Fuel Type*



Source: Company Reports, BMO Capital Markets

Exhibit 30: *Market Exposure in Portfolio*



Source: Company Reports, BMO Capital Markets

Table 28: *Summary of Power Generation Assets*

Facility	Location	Fuel Type	Capacity (MW)	Ownership (%)	Net Capacity (MW)	Electricity Purchaser	Contract Expiry Date
Battle River 3,4 & 5	AB	Coal	670.0	100.0%	670.0	ENMAX	2013,2013 & 2020
Brighton Beach	ON	Natural Gas	580.0	50.0%	290.0	Shell Energy	2024
Cory	SK	Natural Gas	260.0	50.0%	130.0	SaskPower/Potash	2028
Joffre	AB	Natural Gas	480.0	40.0%	192.0	Nova/ Merchant	2020
McMahon	BC	Natural Gas	120.0	50.0%	60.0	BC Hydro	2014
Muskeg River	AB	Natural Gas	170.0	70.0%	119.0	Athabasca/Merchant	2042
Oldman River	AB	Hydroelectric	32.0	75.0%	24.0	Merchant	n/a
Poplar Hill	AB	Natural Gas	45.0	100.0%	45.0	Merchant/ TMR	2018
Primrose	AB	Natural Gas	85.0	50.0%	42.5	CN Resources/Merchant	2028
Rainbow Lake 2	AB	Natural Gas	38.0	100.0%	38.0	Merchant	n/a
Rainbow Lake 4 & 5	AB	Natural Gas	90.0	50.0%	45.0	Merchant/ TMR	2010
Scotford	AB	Natural Gas	170.0	100.0%	170.0	Athabasca/Merchant	2043
Sheerness 1 & 2	AB	Coal	760.0	50.0%	380.0	TransCanada	2020
Valleyview 1 & 2	AB	Natural Gas	90.0	100.0%	90.0	Merchant	n/a
Barking	UK	Natural Gas	1,000.0	25.5%	255.0	Merchant	n/a
Total			**4,590.0**		**2,550.5**		

Notes: (1) TMR - Transmission Must Run.
Source: Company Reports

ATCO Midstream

ATCO Midstream owns and operates the non-regulated Carbon Facility and natural gas gathering, processing and NGL extraction facilities in Alberta, Saskatchewan, and the Northwest Territories. ATCO Midstream also provides natural gas procurement and load balancing services for other ATCO subsidiaries.

The midstream segment includes the following assets:

Table 29: *Summary of Midstream Assets*

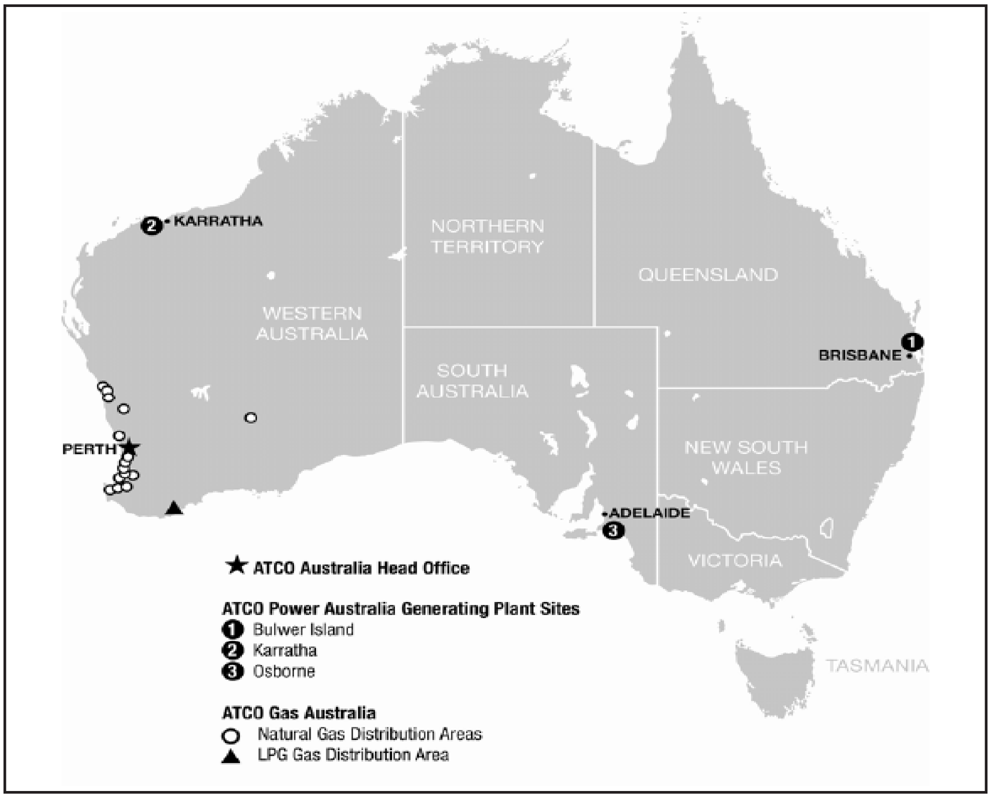
Facility	Date in Service	NGL Extracted	Licensed Capacity (mmcf/day)	Ownership (%)	Net Ownership (mmcf/day)	Operator
Extraction Operations						
Edmonton Ethane Extraction Plant	1978	(1)	390.0	51.3%	200.0	No
Empress Gas Liquids Straddle Plant	1983	(1)	1,100.0	12.2%	134.0	Yes
Fort Saskatchewan Ethane Extraction Plant	1984	(2)	37.0	100.0%	37.0	Yes
Villeneuve Ethane Extraction Plant	1997	(2)	40.0	100.0%	40.0	Yes
			1,567.0		**411.0**	
Processing Operations						
Carbondale Gas Plant	1991	n/a	56.0	100.0%	56.0	Yes
Cranberry Gas Plant	1981	n/a	36.0	100.0%	36.0	Yes
Golden Spike Gas Plant	1999	n/a	65.0	100.0%	65.0	Yes
Ikhil Gas Plant	1999	n/a	8.0	33.3%	3.0	No
Kinsella Gathering and Compression Facility	1996	n/a	20.0	100.0%	20.0	Yes
Kisbey Gas Plant	2000	n/a	5.0	50.0%	3.0	Yes
Nottingham Gas Plant	1985	n/a	18.0	8.0%	1.0	No
Puskwaskau Gas Plant	1996	n/a	21.0	41.0%	9.0	No
Watelet Gas Plant	1998	n/a	20.0	100.0%	20.0	Yes
			249.0		**213.0**	

Notes: (1) Ethane and a mixture of propane, butane and pentanes plus.
(2) A mixture of ethane, propane, butane and pentanes plus.
Source: Company Reports

3. ATCO Australia

This segment is involved in energy, power generation and infrastructure in Australia.

Exhibit 31: *Map of ATCO Australia*



Source: Company Reports

We note the following about Exhibit 31:

- ATCO Gas Australia is the natural gas distribution utility that serves the city of Perth and surrounding areas. It has 650,000 customers (98% residential, 2% commercial) and owns 13,100 km of natural gas pipelines. ATCO Gas Australia is regulated primarily by the Economic Regulation Authority (ERA) of Western Australia and rates are generally set for a five-year period. Under a cost of service regulatory mechanism, the ERA establishes the revenues for each year of the five-year period in order to recover a return on projected rate base, depreciation and projected operating costs.
- ATCO Power Australia consists of interests in three natural gas-fired generating plants in Adelaide, Brisbane and Karratha. The 50%-owned Brisbane and Adelaide facilities have contract expiry dates of 2021 and 2018, respectively, while the 100%-owned Karratha facility has a contract expiry date of 2030. The facilities have a combined net generating capacity of 193 MW.
- ATCO I-Tek Australia primarily provides information technology services to ATCO Gas Australia and Dampier Bunbury Pipelines. Its services include day-to-day operational support through to architectural design and program delivery.

4. Corporate & Other Segment

The Corporate & Other segment includes ATCO I-Tek, commercial real estate in Alberta and the company's 24.5% equity investment in ATCO Structures & Logistics.

Earnings Estimates

We are introducing the following estimates:

Table 30: *Canadian Utilities' Estimates*

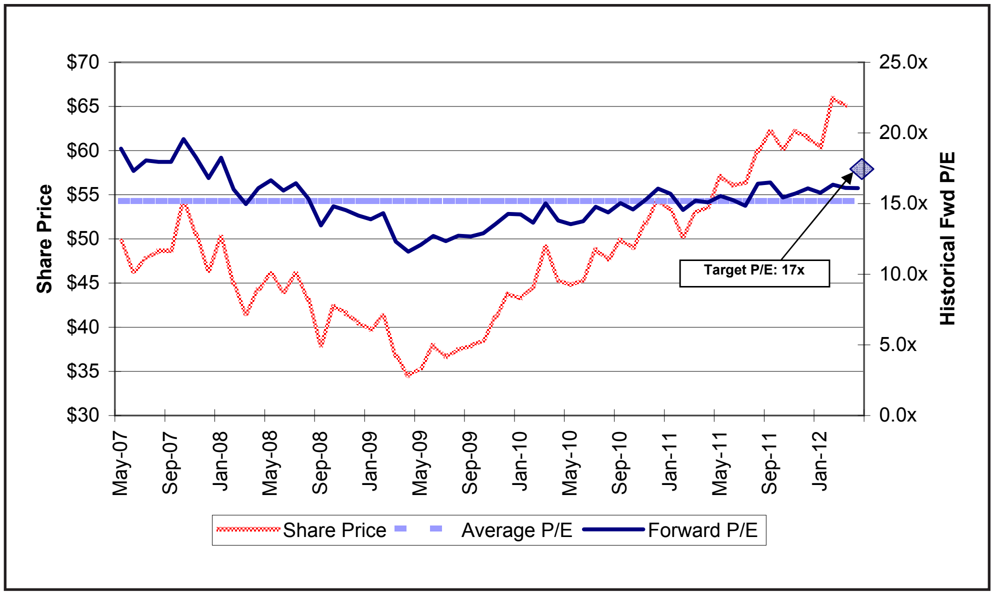
	2012E	2013E
Segmented Earnings		
Utilities	280.9	322.7
Energy	145.7	134.9
ATCO Australia	37.8	39.9
Corporate & Other	51.7	51.7
Total Segmented Earnings	**516.0**	**549.2**
Cash Flow From Operations	**1,406.4**	**1,496.6**
Total Capital Expenditures	**1,834.3**	**2,153.3**
Average shares o/s (basic)	127.6	132.6
Average shares o/s (diluted)	128.1	133.1
EPS (basic)	**$4.04**	**$4.14**
EPS (diluted)	**$4.03**	**$4.13**
First Call Consensus	***$4.04***	***$4.26***

Source: BMO Capital Markets, Thomson ONE

Valuation – Target Price $70

Our target price of $70 represents a 17x 2013E EPS, which is a discount to its peer group but at the upper end of its five-year historical trading range. We believe the upper end of the range is justified given an improvement in earnings quality and visibility (utility operations is expected to increase to ~66% of earnings in 2013 vs. ~54% in 2011, with the possibility of ~77% regulated utility exposure by 2015) and the secular reduction observed in 10-year government of Canada bond yields.

Exhibit 32: *Canadian Utilities – Forward P/E, Share Price, and Target P/E*



Source: Thomson One, Bloomberg

At current levels, CU is trading at a P/E of 16.4x in 2012E (vs. 16.1x for our Canadian utility peer group) and 16.0x in 2013E (vs. the group average at 15.5x).

Table 31: *Peer Group Valuation Table*

	Ticker	Price 05-Apr-12	High 52 Wk	Low 52 Wk	12-Month Target	ROR Target	Rating (1)	Shares O/S (mm)	Market Cap. (mm)	EPS 2010A	EPS 2011E	EPS 2012E	EPS 2013E	CAGR ('11-'13)	P/E 2010A	P/E 2011A	P/E 2012E	P/E 2013E	EV/EBITDA 2013E	Dividend Rate (4)	Dividend Yield
Utilities																					
ATCO Ltd. (2)	ACO/X	$70.35	$71.50	$55.34	NA	NA	NR	57.7	$4,061.3	$5.04	$5.70	$6.22	$6.41	6.0%	10.1	10.6	11.3	11.0	NA	$1.31	1.9%
Canadian Utilities Ltd.	CU	$66.12	$68.12	$51.54	$70.00	8.5%	OP	127.6	$8,438.1	$3.32	$3.63	$4.03	$4.13	6.5%	14.2	15.6	16.4	16.0	10.0	$1.77	2.7%
Caribbean Utilities (3)	CUP.U	$9.95	$10.49	$9.01	$9.50	2.1%	Und	28.6	$284.8	$0.67	$0.67	$0.67	$0.70	2.0%	13.0	13.9	14.9	14.3	10.6	$0.66	6.6%
Emera Inc.	EMA	$33.75	$34.92	$19.95	$34.00	4.7%	Mkt	122.2	$4,125.4	$1.65	$1.65	$1.72	$1.84	5.7%	16.1	19.3	19.6	18.3	13.2	$1.35	4.0%
Fortis Inc.	FTS	$32.11	$34.39	$28.24	$34.50	11.2%	OP	188.8	$6,063.8	$1.60	$1.66	$1.74	$1.81	4.4%	18.4	19.7	18.5	17.8	10.6	$1.20	3.7%
Average						**6.6%**								**4.9%**	**14.4**	**15.8**	**16.1**	**15.5**	**11.1**		**3.8%**
Power																					
Boralex Inc.	BLX	$8.00	$9.00	$5.85	$9.00	12.5%	Mkt	37.7	$301.8	($0.15)	($0.07)	($0.07)	($0.29)	nmf	nmf	nmf	nmf	nmf	14.5	$0.00	0.0%
Capital Power Corp.	CPX	$23.40	$28.00	$21.50	$26.00	16.5%	OP	97.2	$2,274.1	$1.40	$1.24	$1.44	$1.64	14.9%	16.3	20.1	16.3	14.3	8.4	$1.26	5.4%
TransAlta Corp.	TA	$18.12	$23.42	$18.25	$19.00	11.3%	Mkt	224.6	$4,070.0	$0.88	$1.04	$1.12	$1.15	5.3%	24.5	20.5	16.1	15.8	8.0	$1.16	6.4%
Average						**13.4%**								**10.1%**	**20.4**	**20.3**	**16.2**	**15.0**	**10.3**		**3.9%**

Notes:
(1) Ratings Key: Outperform – OP; Market Perform – Mkt; Underperform – Und.; Not Rated – NR; Restricted - R
(2) Estimates per First Call
(3) All figures in US Dollars
(4) Recent dividend/distribution annualized
Source: BMO Capital Markets, Thomson One

Risks

- **Regulation:** Decisions by various regulatory bodies can positively or negatively affect the company's financial results. Canadian Utilities is affected by determinations made by the Alberta Utilities Commission, with respect to rates and allowed return on equity. Other influential regulatory bodies include the Economic Regulation Authority of Western Australia.
- **Currency Risk:** the company's earnings from its foreign investments are exposed to changes in foreign exchange rates (Australia and the U.K.). This foreign exchange impact is partially offset by foreign-denominated debt and the company's hedging activities.
- **Commodity Risk:** Canadian Utilities Limited has the following direct exposures to commodity prices: (1) some of its power generation facilities are not contracted, which exposes the company's cash flow to changes in merchant electricity prices in Alberta and the U.K.; (2) through the company's fractionation facilities; and (3) storage price differentials.
- **Access to Capital Markets:** Canadian Utilities is largely dependent on continued access to capital markets to finance planned growth. The pricing of future capital will have a direct effect on the company's profitability. To the extent that the company faces reduced access to the capital markets, we believe that its ability to complete its projects may be limited.

Canadian Utilities Limited Management Team

Table 32: *Management Overview*

Name	Position	Employment History
Nancy C. Southern	President & Chief Executive Officer	- Ms. Southern has been President and CEO of Canadian Utilities Ltd. and ATCO Ltd. since January 1, 2003. Previously she was co-Chairman and COO from 2000 until 2003, Deputy CEO from 1998 until 2000m and Deputy Chairman from 1996 until 1998.
Siegfried W. Kiefer	Chief Operating Officer, Energy & Utilities, ATCO Group	- Mr. Kiefer was appointed in 2004 to the position of Managing Director, Utilities Business Group, Canadian Utilities Limited. - Since joining ATCO in 1983, Mr. Kiefer has held progressively senior roles in ATCO Ltd. and Canadian Utilities Limited.
Brian R. Bale	Senior Vice President & Chief Financial Officer	- Mr. Bale was appointed Senior VP & CFO of Canadian Utilities effective December 1, 2009. Previously, he was a Senior VP, Finance & Regulatory at ATCO Gas. - Since joining ATCO in 1981, Mr. Bale has held a variety of finance and regulatory management positions within the Corporation and was appointed an officer of ATCO Gas in 2005.
Susan R. Werth	Senior Vice President & Chief Administration Officer	- Ms. Werth was appointed to the role of SVP & Chief Administration Officer in 2000. Previously, Ms. Worth was VP, Administration, a role she was appointed to in 1995.

Source: Company Reports

Table 33: *Consolidated Summary Sheet*

	Year Ending December 31									CAGR 2011A-2013E
	2005	2006	2007	2008	2009	2010	2011	2012E	2013E	
Total Basic EPS	$2.04	$2.59	$2.75	$3.16	$3.22	$3.32	$3.64	$4.04	$4.14	6.7%
Total Diluted EPS	$2.03	$2.58	$2.74	$3.15	$3.22	$3.32	$3.63	$4.03	$4.13	6.5%
First Call Consensus								*$4.04*	*$4.26*	
Segmented EPS										
Reg Gas/Utilities	$0.78	$0.96	$1.00	$1.14	$1.47	$1.80	$1.82	$2.19	$2.42	15.5%
Energy	$1.44	$1.76	$1.81	$2.12	$1.49	$1.20	$1.28	$1.14	$1.01	-11.2%
ATCO Australia	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.13	$0.29	$0.30	54.7%
Corporate & Intersegment/Other	($0.19)	($0.14)	($0.07)	($0.11)	$0.26	$0.32	$0.41	$0.40	$0.39	-2.4%
Dividends	$1.10	$1.15	$1.25	$1.33	$1.41	$1.51	$1.62	$1.77	$1.87	7.6%
Payout Ratio	53.99%	44.36%	45.42%	42.07%	43.77%	45.50%	44.40%	43.77%	45.16%	
Average Shares (mm)	127.5	126.7	125.9	125.8	125.8	126.0	127.7	128.1	133.1	
Net Book Value	$17.52	$18.54	$20.13	$21.92	$24.20	$26.01	$24.44	$26.71	$30.24	
Market Valuation										
Price: High	$46.20	$48.25	$54.36	$50.23	$45.15	$54.49	$63.88	-	-	
Price: Low	$29.81	$35.64	$42.09	$35.03	$34.10	$41.97	$49.10	-	-	
Price: Current	-	-	-	-	-	-	-	$66.12	-	
P/E Ratio: High	22.8	18.7	19.8	15.9	14.0	16.4	17.6	-	-	
P/E Ratio: Low	14.7	13.8	15.4	11.1	10.6	12.7	13.5	-	-	
P/E Ratio: Current	-	-	-	-	-	-	-	16.4	16.0	
EV/EBITDA Value: High	9.9	9.5	10.6	9.0	8.9	10.1	11.0	-	-	
EV/EBITDA Value: Low	7.7	7.9	9.0	7.4	7.7	8.7	9.5	-	-	
EV/EBITDA: Current	-	-	-	-	-	-	-	10.2	10.0	
Yield: High Price	2.4%	2.4%	2.3%	2.6%	3.1%	2.8%	2.5%	-	-	
Yield: Low Price	3.7%	3.2%	3.0%	3.8%	4.1%	3.6%	3.3%	-	-	
Yield: Current	-	-	-	-	-	-	-	2.7%	2.8%	
Balance Sheet ($mm)										
Debt (S-T)	57.2	59.0	65.4	84.5	51.8	41.6	179.0	42.3	0.0	
Debt (L-T)	2,231.0	2,411.5	2,603.2	2,844.3	3,102.3	3,060.3	3,516.0	4,381.0	5,234.0	
Non-Recourse Debt (L-T)	673.8	626.7	478.1	412.4	354.8	302.8	1,035.0	987.1	944.8	
Preferred Shares	636.5	636.5	625.0	625.0	785.0	860.0	1,067.0	957.0	957.0	
Shareholders' Equity	2,223.5	2,324.7	2,521.7	2,751.7	3,046.1	3,275.2	3,119.0	3,409.1	4,010.4	
	5,822.0	6,058.4	6,293.4	6,717.9	7,340.0	7,539.9	8,916.0	9,776.5	11,146.2	
Balance Sheet (%)										
Debt (S-T)	1.0%	1.0%	1.0%	1.3%	0.7%	0.6%	2.0%	0.4%	0.0%	
Debt (L-T)	38.3%	39.8%	41.4%	42.3%	42.3%	40.6%	39.4%	44.8%	47.0%	
Non-Recourse Debt (L-T)	11.6%	10.3%	7.6%	6.1%	4.8%	4.0%	11.6%	10.1%	8.5%	
Preferred Shares	10.9%	10.5%	9.9%	9.3%	10.7%	11.4%	12.0%	9.8%	8.6%	
Shareholders' Equity	38.2%	38.4%	40.1%	41.0%	41.5%	43.4%	35.0%	34.9%	36.0%	
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
Income Statement ($mm)										
Total Revenue	2,513.4	2,430.4	2,404.9	2,778.9	2,575.3	2,639.8	2,997.0	3,336.0	3,513.7	8.3%
EBITDA	959.5	1,039.7	1,003.3	1,136.4	1,118.1	1,102.4	1,274.0	1,461.1	1,587.3	11.6%
EBIT	648.0	691.2	651.8	747.3	788.4	766.9	909.0	920.7	989.9	4.4%
Net Earnings	258.6	327.1	345.2	396.5	404.6	417.6	464.0	516.0	549.2	8.8%
Cash Flow from Operations	659.3	657.5	725.9	804.6	793.4	738.2	1,319.0	1,406.4	1,496.6	6.5%
Key Statistics										
ATCO Gas (North & South)										
Average Utility Rate Base ($mm)	988.3	1,067.0	1,108.6	1,229.8	1,386.6	1,410.0	1,524.0	1,745.7	1,918.7	12.2%
Growth Rate	5.0%	8.0%	3.9%	10.9%	12.8%	1.7%	8.1%	14.5%	9.9%	
Allowed Return on Equity	9.50%	8.93%	8.51%	8.75%	9.00%	9.00%	8.75%	8.75%	8.75%	
Deemed Equity	38.00%	38.00%	38.00%	38.00%	39.00%	39.00%	39.00%	39.00%	39.00%	
ATCO Electric (Transmission)										
Average Utility Rate Base ($mm)	770.9	838.3	879.7	923.2	965.0	1,275.0	1,940.0	3,009.2	3,528.1	34.9%
Growth Rate	11.1%	8.7%	4.9%	4.9%	4.5%	32.1%	52.2%	55.1%	17.2%	
Allowed Return on Equity	9.50%	8.93%	8.51%	8.75%	9.00%	9.00%	8.75%	8.75%	8.75%	
Deemed Equity	33.00%	33.00%	33.00%	33.00%	36.00%	36.00%	37.00%	37.00%	37.00%	
ATCO Electric (Distribution)										
Average Utility Rate Base ($mm)	607.7	893.8	1,009.6	1,155.1	973.1	1,104.3	1,193.0	1,429.3	1,777.1	22.0%
Growth Rate	6.8%	47.1%	13.0%	14.4%	-15.8%	13.5%	8.0%	19.8%	24.3%	
Allowed Return on Equity	9.50%	8.93%	8.51%	8.75%	9.00%	9.00%	8.75%	8.75%	8.75%	
Deemed Equity	37.00%	37.00%	37.00%	37.00%	39.00%	39.00%	39.00%	39.00%	39.00%	
ATCO Pipelines (North & South)										
Average Utility Rate Base ($mm)	585.4	641.5	706.2	711.1	746.0	759.0	825.0	870.2	915.9	5.4%
Growth Rate	4.6%	9.6%	10.1%	0.7%	4.9%	1.7%	8.7%	5.5%	5.3%	
Allowed Return on Equity	9.50%	9.50%	9.50%	8.75%	9.00%	9.00%	8.75%	8.75%	8.75%	
Deemed Equity	43.00%	43.00%	43.00%	43.00%	45.00%	45.00%	45.00%	38.00%	38.00%	

Note: Priced as of market close on April 5, 2012.
Source: BMO Capital Markets, Company Reports

Caribbean Utilities

Initiating Coverage at Underperform

Caribbean Utilities (CUP.U-TSX)
Price: $9.95 (Apr-5-12)
Target: $9.50

Investment Summary

- **We are initiating coverage of Caribbean Utilities Company, Ltd. with an Underperform rating and a US$9.50 target price.** Our target price represents 13.5x 2013E EPS, which is lower than what we use to value similar companies due to low trading liquidity and ongoing weakness in the Cayman economy, which we think will limit near-term load growth. Caribbean Utilities is a vertically integrated electric company and holds an exclusive 20-year electricity transmission and distribution licence (expiring April 2028) and a non-exclusive 21.5-year generation licence (expiring September 2029) in Grand Cayman, Cayman Islands. Caribbean Utilities commenced operations as the only public electric utility company in Grand Cayman in 1966.
- **A small market cap stock: US$115 million float and quite illiquid.** CUP.U is quite illiquid, averaging only ~7,500 shares traded per day over the last 100 days. There are approximately 28.5 million Class A Ordinary shares outstanding. Fortis Inc. owns 59.5% or 17.0 million Class A Ordinary shares. The public float is, therefore, approximately 11.5 million Class A Ordinary shares.
- **Capital spending outlook.** In December 2011, the company filed its 2012-2016 Capital Investment Plan totalling US$192 million. The Electricity Regulatory Authority is expected to issue a decision on the plan in Q1/12. The company expects to finance the capital program with a combination of equity, debt and funds from operations with a target capital structure 55% debt and 45% equity (including preferred shares).
- **New generation needs subject to competitive bids**: During 2012, the company will administer a request for proposal solicitation for bids to construct a new 18 MW diesel facility to be commissioned in the 2014 time frame. If third-party bidders are not deemed to be cost competitive, the capacity will be constructed by Caribbean Utilities and added to the company's rate base. Depending on Cayman growth over the next two years, a further 18 MW of generating capacity could be needed in either 2015 or 2016.
- **Highest dividend yield.** Caribbean Utilities' $0.66 per share dividend maps out to a 6.6% yield, which we believe is sustainable given the company's conservative balance sheet (2013E total-debt-to capital of ~55%) and a cash dividend coverage ratio of 2.1x. This yield is the highest among the regulated utility companies we cover.
- **Earnings estimates.** We are introducing EPS forecasts of $0.67 in 2012 and $0.70 in 2013.
- **Relative valuation.** At current levels, Caribbean Utilities is trading at a P/E of 14.9x in 2012E (vs. 16.1x for our Canadian utility peer group) and 14.3x in 2013E (vs. the peer average at 15.5x).

Corporate Overview

Caribbean Utilities' electric power system currently consists of a total installed capacity of 151.2 MW, seven major transformer substations, and approximately 345 miles of high-voltage transmission and distribution lines.

- **Generation.** Grand Cayman has no indigenous energy sources; therefore, the company relies exclusively on imported diesel fuel from the Caribbean and the Gulf of Mexico to produce electricity. Demand growth is largely driven by weather-related space cooling requirements. Peak load (usually reached in August) has grown at an annual rate of 2.7% over the 10-year period ending December 31, 2011. With the decline in work permit holders since 2009 and increased conservation efforts mostly from the residential class, we see limited peak load growth over our forecast period.
- **Transmission and Distribution.** There are seven major transformer stations and approximately 345 miles of overhead and submarine high-voltage (69 kV and 13 kV) transmission and distribution lines in Grand Cayman. These lines and substations are designed for high winds and flooding that might result from a hurricane.

Valuation – Target Price US$9.50

Our US$9.50 target price reflects 13.5x P/E based on our 2013 estimates, which is in line with its five-year average of 13.3x but lower than what we use to value similar companies. We believe this discount is warranted given low trading liquidity and ongoing weakness in the Cayman economy, which we think will limit near-term load growth.

Risks

Caribbean Utilities shares are subject to the following risks:

1. **Hurricanes:** Caribbean Utilities maintains a number of insurance policies aimed at mitigating the potentially negative effect from hurricane-related system damage. The hurricane season is typically during June through November. Substation upgrades and new generation installations are generally housed in facilities designed to withstand hurricane wind speeds, mitigating the potential damage from extreme weather. Also, transmission and distribution poles have been continuously reinforced over time.
2. **Regulation:** The operations of the company are subject to the regulatory determinations of the Electricity Regulatory Authority, with respect to adjustment of billing rates, capital expenditures and the return on rate base. The company is at risk to the potential adverse impact arising from legislative initiatives that alter the governing authority compact and/or regulatory decisions.
3. **Tax Changes:** Our estimates will change if Caribbean Utilities is required to pay income, corporation, capital gains or other taxes. Similarly, no taxes are imposed on holders of the shares, including withholding taxes. Should any of these conditions change, our estimates, and valuation will likely be adversely affected.

4. **Tourism:** Anticipated increases in demand for electric power are highly dependent on new commercial development to support tourism. Of all non-resident arrivals to Grand Cayman, 79% were from the United States during 2011, making the industry dependent on economic conditions in the United States.

Caribbean Utilities Management Team

Table 34: *Management Overview*

Name	Position	Employment History
Richard Hew	President & Chief Executive Officer	- Mr. Hew has been CEO and President of Caribbean Utilities since August 2005. Prior to that he served as VP and COO. - Mr. Hew joined CUC in June 1998. His previous positions include Senior VP and GM, VP of Transmission & Distribution, Manager of T&D Planning and Operations and Protection Engineer.
Letitia Lawrence	Vice President & Chief Financial Officer	- Ms. Lawrence was appointed to her present position in August 2007 and prior to that time served as Manager, Financial Services.

Source: Company reports

Table 35: Consolidated Summary Sheet

	Year Ended April 30				Year Ended Dec. 31						CAGR
	2005	2006	2007	2008	TY2008	2009	2010	2011	2012E	2013E	2011A-2013E
Earnings Per Share	$0.13	$0.87	$0.84	$0.90	$0.45	$0.67	$0.67	$0.67	$0.67	$0.70	2.0%
Dividends	$0.50	$0.66	$0.66	$0.66	$0.50	$0.66	$0.66	$0.66	$0.66	$0.66	-0.1%
Payout Ratio	377.3%	75.7%	78.1%	73.3%	113.0%	98.7%	98.9%	98.8%	98.8%	94.9%	
Average Shares	24.9	25.2	25.3	25.4	26.7	28.0	28.4	28.5	28.6	28.8	
Net Book Value	$5.02	$5.29	$5.34	$5.60	$6.05	$6.09	$6.11	$6.16	$6.14	$6.16	
Market Valuation											
Price: High	$13.00	$12.21	$13.50	$12.85	$12.19	$9.05	$9.78	$9.80	-	-	
Price: Low	$9.75	$10.69	$11.40	$11.35	$6.10	$6.77	$8.25	$8.90	-	-	
Price: Current	-	-	-	-	-	-	-	-	$9.95	-	
P/E Ratio: High	98.2	14.0	16.0	14.3	27.4	13.5	14.7	14.6	-	-	
P/E Ratio: Low	19.5	16.2	17.3	17.2	12.1	10.2	12.5	13.5	-	-	
P/E Ratio: Current	-	-	-	-	-	-	-	-	14.9	14.3	
EV/EBITDA: High	29.3	12.6	11.6	10.7	18.4	10.5	10.2	10.6	-	-	
EV/EBITDA: Low	24.2	11.5	10.4	9.9	12.5	9.0	9.2	10.1	-	-	
EV/EBITDA Value: Current	-	-	-	-	-	-	-	-	10.7	10.6	
Yield: High Price	3.8%	5.4%	4.9%	5.1%	5.4%	7.3%	6.7%	6.7%	-	-	
Yield: Low Price	5.1%	6.2%	5.8%	5.8%	10.8%	9.8%	8.0%	7.4%	-	-	
Yield: Current	-	-	-	-	-	-	-	-	6.6%	6.6%	
Balance Sheet ($mm)											
Debt (S-T)	16.4	7.6	27.5	22.5	26.4	22.0	32.5	21.5	44.9	64.6	
Debt (L-T)	126.0	148.5	138.0	166.3	152.4	178.1	161.2	186.9	167.6	150.6	
Deferred Items	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Preferred Shares	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Shareholders' Equity	125.7	133.7	135.3	142.4	170.0	171.8	173.8	176.1	176.4	177.4	
	268.2	289.9	300.8	331.1	348.8	371.9	367.5	384.6	388.9	392.6	
Balance Sheet (%)											
Debt (S-T)	6.1%	2.6%	9.1%	6.8%	7.6%	5.9%	8.8%	5.6%	11.5%	16.5%	
Debt (L-T)	47.0%	51.2%	45.9%	50.2%	43.7%	47.9%	43.9%	48.6%	43.1%	38.4%	
Deferred Items	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Preferred Shares	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Shareholders' Equity	46.9%	46.1%	45.0%	43.0%	48.7%	46.2%	47.3%	45.8%	45.4%	45.2%	
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
Income Statement ($mm)											
Total Revenue	92.9	135.7	158.9	176.0	150.3	158.8	180.1	218.1	189.2	193.8	-5.7%
EBITDA	15.9	37.0	43.8	48.0	27.4	43.2	46.3	45.9	46.4	47.4	1.7%
EBIT	2.7	23.4	28.7	31.3	15.2	24.0	25.9	25.0	25.5	26.2	2.3%
Net Earnings	4.2	22.9	22.1	23.8	12.6	20.0	19.9	20.0	20.1	20.9	2.3%
Cash Flow from Operations	26.8	35.6	37.5	40.6	28.5	36.6	42.8	41.1	40.9	42.2	1.3%
Key Statistics											
Average Utility Rate Base (CI$mm)	205.0	222.8	239.9	264.1	282.3	298.0	307.2	315.6	325.4	328.3	2.0%
Growth Rate	6.5%	8.7%	7.7%	10.1%	nmf	nmf	3.1%	2.7%	3.1%	0.9%	
Return on Capital	0.56%	8.75%	9.98%	9.88%	nmf	7.39%	7.47%	7.31%	6.91%	6.76%	

Notes:
(1) Financial results for TY 2008 reflect the eight month period from May 1, 2008 to December 31, 2008. Where applicable, ratios have been annualized.
(2) Priced as of market close on April 5, 2012.
Source: Company Reports, BMO Capital Markets

Emera Inc.

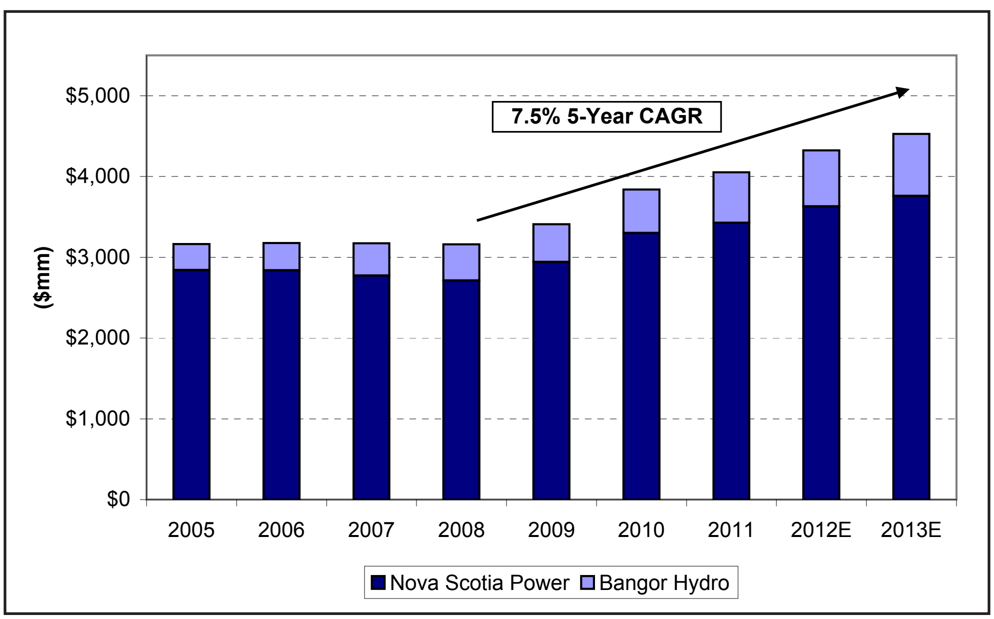
Initiating Coverage at Market Perform; Attractive Growth Profile but Reasonably Valued

Emera Inc. (EMA-TSX)
Price: $33.75 (Apr-5-12)
Target: $34.00

Investment Summary

- **We are initiating coverage of Emera with a Market Perform rating and a $34 target price.** We like Emera's long-term growth profile and admire its recent execution track record. Our neutral stance toward Emera simply reflects relative valuation levels that we consider to be full. Provided that its execution performance remains intact, we see little concern from a relative de-rating standpoint. Our target price of $34 represents 18.5x 2013E EPS, which is toward the upper end of its five-year historical trading range, reflecting strong dividend and earnings growth potential.
- **Safe-haven name with growth in its wings.** We believe investors see EMA as something of a save haven, given that more than 80% of earnings are derived from regulated operations. Organic growth has been among the better in our coverage universe (8.6% CAGR over 2007–2011) following many years of lackluster growth, with EMA benefitting from rate base growth in its core markets of Nova Scotia and Maine (Exhibit 34), as well as contributions from new projects such as the Brunswick Pipeline and its Caribbean acquisitions. The growth in EPS has supported dividend growth of 7.8% over the same period. In our view, Emera's operations are well positioned to achieve further earnings momentum, with total capital expected of ~$2.5 billion over the next five years at Nova Scotia Power ($1.75 billion), Maine Utilities ($500 million) and the Caribbean ($215 million). Our forecast envisions EPS growth of over 5.7% per annum, which falls at the higher end of company guidance of 4–6% per annum.

Exhibit 34: *Rate Base 2005–2013E*



Source: BMO Capital Markets

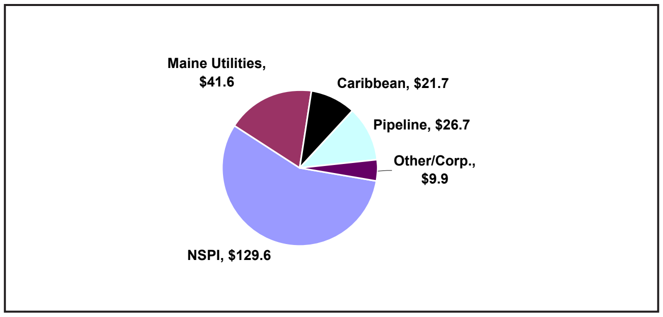
- **Dividend growth potential.** Emera's 2012 capital budget of $623 million is short of our cash flow outlook of $435 million, but the company issued $250 million of medium term notes recently to meet that gap. As it stands now, Emera's $0.3375 per share would map to a 4.0% yield, second only to Caribbean Utilities (6.6%) in our Canadian utility peer group. Our 2012 outlook envisions a 3.7% bump at the end of the year to $0.35 per share quarterly, which would translate to a yield of 4.1%.
- **Mega projects under development could add further upside.** While its pipeline of development opportunities is flush, meaningful data points are still required. We believe upside to our earnings and valuation is possible should Emera succeed in securing contracts and regulatory approval of high potential projects, such as the Lower Churchill ($1.8 billion investment) and the Northeast Energy Link ($2 billion 50/50 JV with National Grid), but where we do not currently ascribe value.
- **Earnings estimates.** We are introducing EPS (f.d) forecasts of $1.72 in 2012 and $1.84 in 2013.
- **Relative valuation – premium levels.** At current levels, Emera is trading at a P/E of 19.6x in 2012E (vs. 16.1x for our Canadian utility peer group) and 18.3x in 2013E (vs. the peer average at 15.5x). We believe this premium valuation could persist given its strong earnings and dividend growth outlook.

Exhibit 35: *Emera at a Glance*

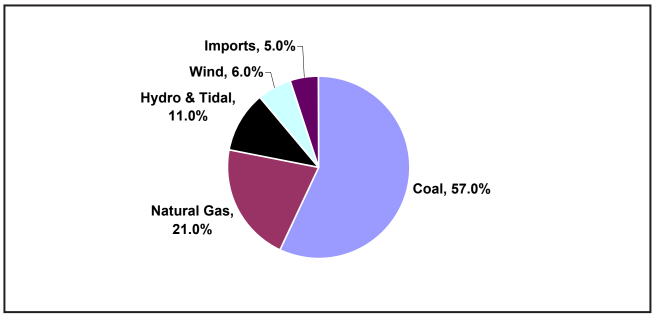
Upcoming Events/Potential Catalysts

May 2012	Q1/12 Results
1H 2012	Expected regulatory filing of Maritime Link project
1H 2012	Final definitive agreement on Lower Churchill
1H 2012	MPUC's decision on First Wind transaction
June 7, 2012	Annual General Meeting
June 2012	Expected sanctioning of Muskrat Falls
Summer 2012	Final Federal environmental rules for coal-fired generation
August 2012	Q2/12 Results
Nov. 2012	Q3/12 Results
Late 2012	Annual Investor Day
Early-to-mid 2013	Expected approval of Labrador-Island project
Early-to-mid 2013	Expected approval of Maritime Link project
Late 2013	Expected sanctioning of Labrador-Island and Maritime Link projects
2017	Expected in-service of All 3 Lower Churchill projects

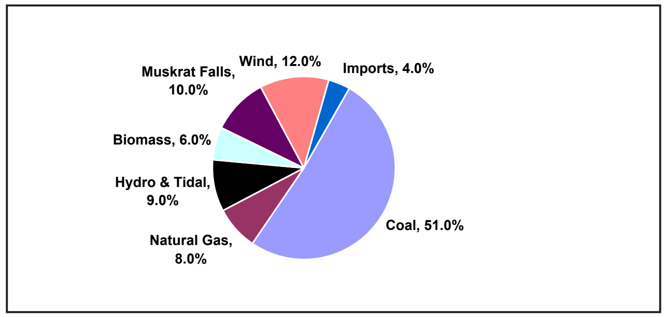
EMA's 2013E Earnings Are Largely From Regulated Businesses ($mm)



NSPI's Current Generation Mix

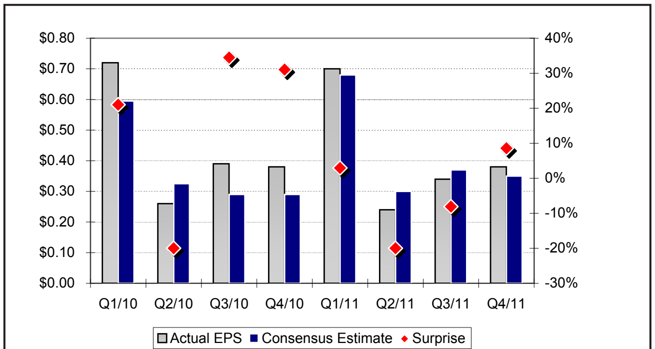


NSPI's Generation Mix - 2020E



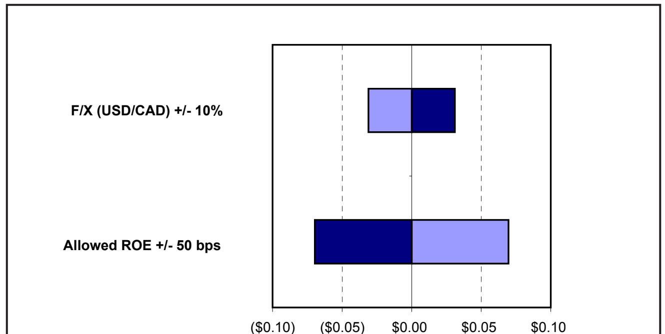
Source: Company Reports, BMO Capital Markets

EPS Surprises vs. Consensus



Source: Company Reports, Thomson One

Sensitivities



Source: BMO Capital Markets

Source: BMO Capital Markets, Company reports

Corporate Overview

***Table 36:** Key Business Segments*

	Net Income [1]	% of Total	Total Assets	% of Total	Capex	% of Total
Nova Scotia Power	123.5	51.2%	3,897.0	56.3%	307.9	62.2%
Maine Utility Operations	37.0	15.3%	963.0	13.9%	91.9	18.6%
Caribbean Utility Operations	46.8	19.4%	848.8	12.3%	69.6	14.1%
Brunswick Pipeline	19.7	8.2%	545.8	7.9%	0.2	0.0%
Other & Eliminations	14.1	5.8%	669.0	9.7%	25.4	5.1%
Total	**241.1**	**100.0%**	**6,923.6**	**100.0%**	**495.0**	**100.0%**

Note:
[1] Attributable to common shareholders.
Source: Company Reports, BMO Capital Markets

1. Nova Scotia Power Inc. (NSPI)

NSPI is a regulated business engaged in the generation, transmission and distribution of electricity to approximately 493,000 customers in Nova Scotia. NSPI, which is the primary electricity supplier in Nova Scotia, has $3.9 billion of assets. The company owns 2,374 MW of generating capacity and, in addition, has contracts to purchase 229 MW of renewable energy (increasing to 259 MW in 2012) from independent power producers. NSPI also owns approximately 5,000 km of transmission facilities and 26,000 km of distribution facilities.

NSPI is subject to cost-of-service regulation under the Nova Scotia Utility and Review Board, with rates set to recover prudently incurred costs of providing electricity service to customers while providing an appropriate return to investors. NSPI's target regulated return on equity range for 2011 was 9.1% to 9.6%, based on an actual, average common equity component of up to 40% of regulated capitalization. The 2012 General Rate Decision adjusted the 2012 ROE range to 9.1% to 9.5%.

As illustrated in Table 37, although NSPI's customer base has generally been evenly distributed among residential, commercial and industrial customers, Nova Scotia Power lost its largest industrial customer (NewPage Port Hawkesbury) in September 2011 and will likely see a decline in industrial sales in 2012 if the mill doesn't come back online. NSPI can recover non-fuel electric charges associated with the mill shutdown pursuant to its 2012 rate decision and thus there should be a minimal earnings impact.

***Table 37:** Electric Sales Volumes by Customer Class – 2009–2011*

	2011		2010		2009	
	GWh	%	GWh	%	GWh	%
Residential	4,275.0	38.1%	4,147.0	36.2%	4,228.0	37.4%
Commercial	3,102.0	27.7%	3,088.0	27.0%	3,107.0	27.5%
Industrial	3,516.0	31.4%	3,908.0	34.1%	3,642.0	32.2%
Other	313.0	2.8%	312.0	2.7%	328.0	2.9%
Total	**11,206.0**	**100.0%**	**11,455.0**	**100.0%**	**11,305.0**	**100.0%**

Source: Company Reports

2. Maine Utility Operations

Emera's Maine Utility Operations are focused on the transmission and distribution of electricity through its wholly owned utilities Bangor Hydro Electric Company and Maine Public Service Company (MPS). Bangor Hydro is the second-largest electric utility in Maine and has approximately $806.8 million of assets, serving approximately 118,000 customers in eastern Maine, while MPS has approximately $139.6 million of assets and serves approximately 36,000 customers in northern Maine. Bangor Hydro owns and operates approximately 1,000 km of transmission facilities and 7,200 km of distribution facilities, and MPS owns and operates approximately 600 km of transmission facilities and 2,900 km of distribution facilities. The Maine Utilities currently have approximately $150 million of additional transmission developments in progress.

The distribution businesses operate under a traditional cost-of-service regulatory structure. Distribution rates are set based on an allowed ROE of 10.2% and a common equity component of 50%. With respect to transmission, Bangor Hydro's local transmission rates are set by the FERC annually on June 1, while MPS's local transmission rates are set annually based on a formula through its Open Access Transmission Tariff. The allowed ROE for Bangor Hydro is 11.14% for local transmission rates and ranges from 11.64–12.64% for bulk transmission. MPS's transmission assets are currently at 10.5%.

As illustrated in Table 38, the Maine Utilities' customer base is largely residential and commercial customers.

***Table 38:** Electric Sales Volumes by Customer Class – 2009–2011*

	2011		2010		2009	
	GWh	%	GWh	%	GWh	%
Residential	778.5	38.6%	591.0	37.9%	591.5	38.6%
Commercial	846.4	42.0%	594.1	38.1%	588.0	38.4%
Industrial	380.5	18.9%	363.0	23.3%	342.0	22.3%
Other	11.4	0.6%	11.6	0.7%	11.6	0.8%
Total	**2,016.8**	**100.0%**	**1,559.7**	**100.0%**	**1,533.1**	**100.0%**

Source: Company Reports

3. Caribbean Utility Operations

Emera's Caribbean Utility Operations include:

- An 80.1 percent investment in Light & Power Holdings Ltd. and its wholly owned subsidiary Barbados Light & Power Company Ltd. (BLPC). BLPC is a vertically integrated utility and the sole provider of electricity on the island of Barbados, serving approximately 123,000 customers. BLPC has been granted a franchise to produce, transmit and distribute electricity on the island of Barbados until 2028 and is regulated under a cost-of-service model by the Fair trading Commission. BLPC's approved regulated return on assets for 2011 was 10%, which included a fuel pass-through mechanism to ensure fuel cost recovery.
- A 50% direct interest and 30.4% indirect interest in Grand Bahama Power Company Ltd. (GBPC). GBPC is a vertically integrated utility and the sole provider of electricity on Grand Bahama Island, serving approximately 19,000 customers. GBPC has been

granted a licence to transmit and distribute electricity on the island by the Grand Bahama Power Authority until 2054. In addition, there is a fuel pass-through mechanism and flexible tariff adjustment policy in place to ensure costs are recovered and a reasonable return is earned.

- A 19.1% interest in St. Lucia Electricity Services Limited, a vertically integrated electric utility on the island of St. Lucia.

4. Other Investments

Emera's other investments include:

- **Maritimes & Northeast Pipeline.** A 12.9% ownership interest in a 1,400 km pipeline that transports natural gas from the Sable reserves to markets in the Maritimes and northeastern U.S.
- **Brunswick Pipeline.** A wholly owned 145 km pipeline that ships natural gas under a take-or-pay contract from the Canaport LNG terminal near Saint John, New Brunswick, to markets in the northeastern U.S. Brunswick Pipeline is accounted for as a direct financing lease.
- **Emera Energy.** A physical natural gas and electricity marketing company.
- **Bayside Power.** A 260 MW gas-fired combined cycle power plant.
- **Bear Swamp.** A 50% interest in a 600 MW pumped storage hydro-electric generating facility located in northern Massachusetts.
- **Emera Utility Services.** Atlantic Canada's largest utility services contractor.
- **Emera Newfoundland & Labrador Holdings Inc.** (ENL). ENL is focused on transmission investments related to the proposed 824 MW Muskrat Falls hydroelectric generating facility in Labrador.
- **Algonquin Power & Utilities Corp.** Emera currently owns a 6.3% equity interest in Algonquin, with pending transactions possibly increasing equity interest to the 25% level by 2012/2013, which is the maximum level that is allowable under Emera and Algonquin's strategic investment agreement.

Proposed Projects Not Priced in Our Outlook

1. Lower Churchill

The most significant component of Emera's longer-term developments is the Lower Churchill Project. While it remains in advanced stages with Nalcor (100% Province of Newfoundland and Labrador) on a definitive agreement, Emera points to a total cost for the project of $6.2 billion, where Emera's share is $1.8 billion ($600 million for its share of the transmission link connecting Newfoundland to Labrador and $1.2 billion for the Maritime Link), which could generate $0.15–0.20 in annualized EPS come 2017, its first full year in service. Using our target P/E of 18.5x, this could add roughly $3–4 per share (undiscounted) to our net asset value. Table 39 illustrates the price upside under various targeted multiples, further discounted by 10% as well as 15% to 2013E.

***Table 39:** Lower Churchill – Potential Upside to NAV*

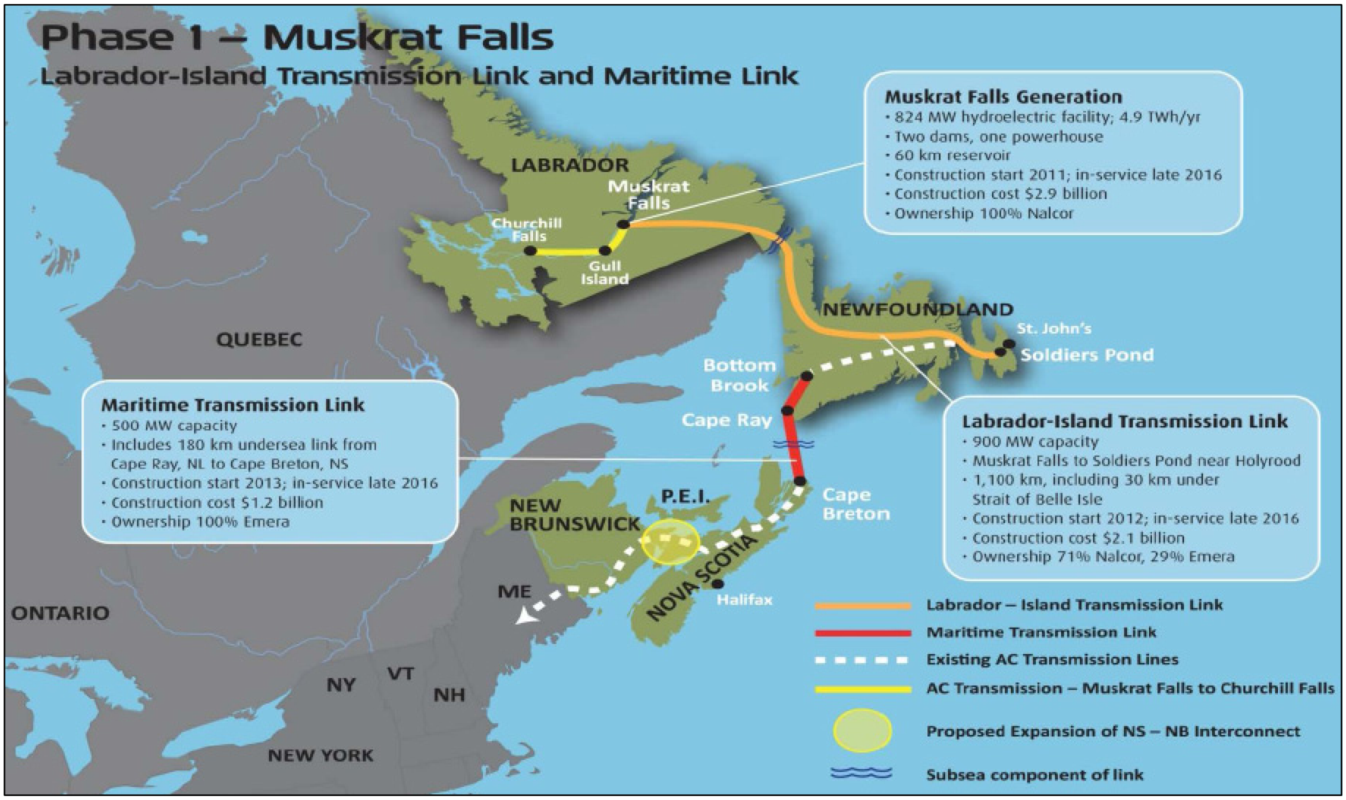
		Expected EPS Accretion		
	Target P/E	*$0.15*	*$0.18*	*$0.20*
2017E	17.5x	$2.63	$3.06	$3.50
	18.5x	$2.78	$3.24	$3.70
	19.5x	$2.93	$3.41	$3.90
Discounted @ 10%	17.5x	$1.79	$2.09	$2.39
	18.5x	$1.90	$2.21	$2.53
	19.5x	$2.00	$2.33	$2.66
Discounted @ 15%	17.5x	$1.50	$1.75	$2.00
	18.5x	$1.59	$1.85	$2.12
	19.5x	$1.67	$1.95	$2.23

Source: BMO Capital Markets, Company Reports

The components of the project are as follows:

- **Generation – Muskrat Falls:** Nalcor will fund and own the $2.9 billion, 824 MW generating station at Muskrat Falls, which is the smaller of two proposed Lower Churchill developments. The Muskrat Falls facility is expected to produce 4.9 TWh of electricity per year. Approximately 2 TWh of this electricity will be used by Nalcor to offset lost generation from the 500 MW Holyrood facility, which burns Bunker C fuel oil. Holyrood is expected to be decommissioned when Muskrat Falls is placed into service. Emera will have the right to 1 TWh of electricity produced by the hydro plant. The remaining 1.9 TWh of annual production is expected to be marketed into New Brunswick and New England. Nalcor will retain the right to this power. Muskrat recently passed the federal and provincial environmental assessment process but still needs to clear the regulatory hurdle (Public Utilities Board is currently conducting a public hearing process) and secure federal authorizations from Fisheries and Oceans Canada and Transport Canada. Project sanctioning is expected at the end of June 2012.
- **Transmission Between Labrador And Newfoundland – Labrador-Island Transmission Link:** Emera and Nalcor will jointly develop transmission in Newfoundland and Labrador to enable the movement of Lower Churchill energy through a joint venture that is 71% owned by Nalcor and 29% by Emera. The joint venture will establish a new regulated transmission utility in Newfoundland and Labrador. The project is expected to cost $2.1 billion, with Emera investing its 29% share of $600 million. The project still requires environmental and regulatory approval.
- **Transmission Between Newfoundland and Nova Scotia – Maritime Transmission Link:** Emera will completely finance and own this $1.2 billion, subsea transmission interconnection between Newfoundland and Nova Scotia in return for 20% of the energy output from Muskrat Falls for 35 years. In December 2011, Emera filed for an environmental assessment, which is expected to be completed within 12–18 months. In addition, the company plans to file the project with the Nova Scotia Utility and Review Board in early 2012, with that approval process expected to take roughly one year. Emera envisions formal sanctioning of the project in late 2013, with construction expected in 2014 and a targeted in-service date of 2017.

Exhibit 36: *Map of Lower Churchill Project*



Source: Company Presentations

A profile of the planned expenditures related to the project is set out in Table 40. Key dates associated with the Maritime Link project are set out in Table 41.

Table 40: *Lower Churchill – Emera's Projected Share of Total Capital Expenditures (Includes AFUDC)*

($ millions)	2012E	2013E	2014E	2015E	2016E	Total
Lower Churchill	100.0	235.0	500.0	600.0	550.0	1,985.0

Source: Company Presentations

Table 41: *Maritime Link Project Schedule*

Date	Event
Q3/2011	Federal Loan Guarantee
Q4/2011	Environmental Registration
2012	NS UARB Review
2013	Project Sanction
2014	Construction Starts
2017	First Power

Souce: Emera Investor Presentation

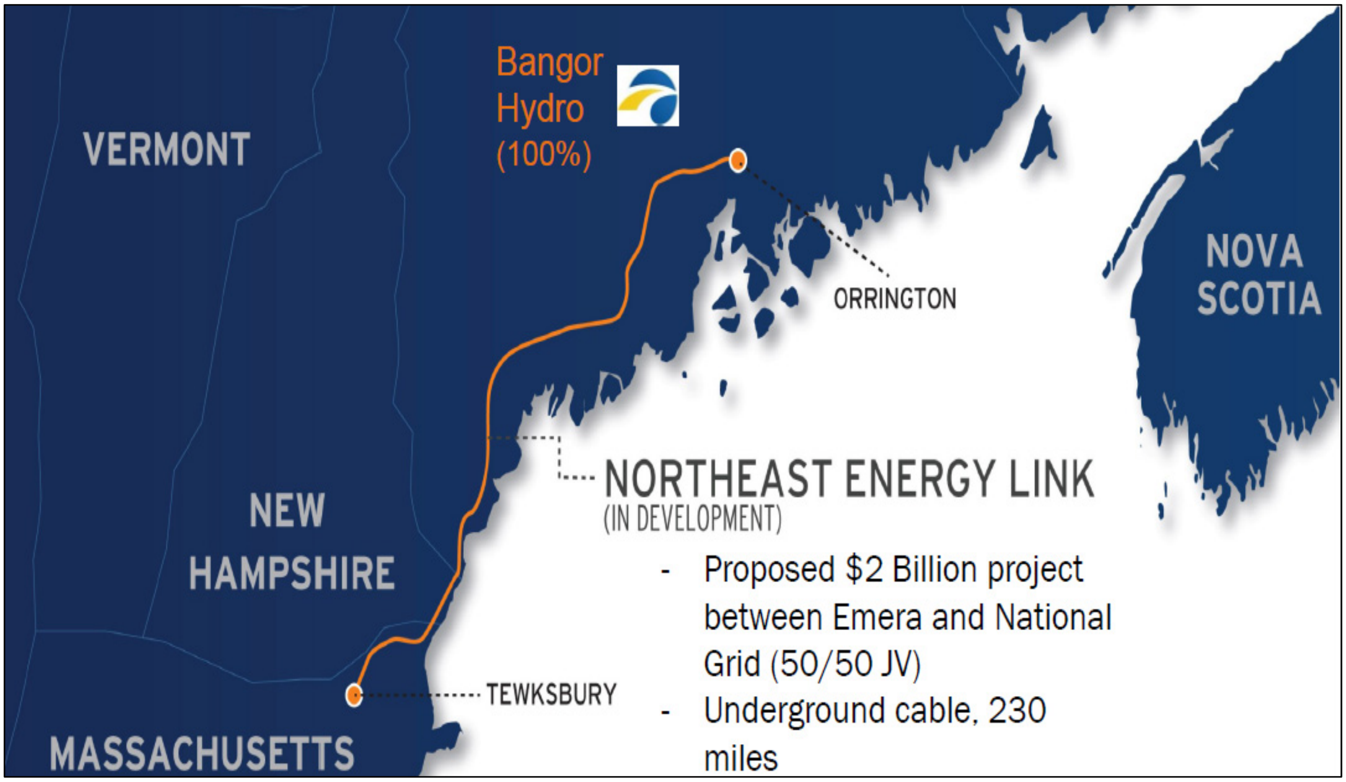
2. First Wind

Emera and Algonquin (AQN-TSX, not rated) had initially planned to form a joint venture (owned 75% by EMA and 25% by AQN) to acquire a 49% interest in 370 MW of wind energy projects in the U.S. Northeast, with First Wind (the developer) owning the 51% balance. However, the Maine Public Service staff issued a report on January 13 recommending the Commission not approve the First Wind transaction. Following the staff recommendation, Algonquin announced that it would not be proceeding with the transaction, but Emera continues to work through the regulatory proceeding in Maine. As it stands now, Emera intends to acquire the 49% interest itself for US$353 million (including a US$150 million loan). A Commission decision on the acquisition is expected to be issued in Q1/12.

3. Northeast Energy Link

The $2 billion Northeast Energy Link (NEL) initiative is a project that is jointly owned by Bangor Hydro and National Grid, and would consist of a 230-mile 1,100 MW HVDC transmission line that would bring renewable power from Maine (i.e., First Wind transaction) and backstopped by firm renewable power (including Muskrat Falls) from the Canadian Atlantic provinces for delivery to the New England market. Although the project was originally conceived as a traditional transmission line, in July 2011, we note that Bangor Hydro and National Grid filed an application with the U.S. Federal Energy Regulatory Commission to position the NEL as a developer-funded line. The funding model proposed by National Grid and Bangor Hydro would see First Wind Holdings subscribe for the majority of the line's capacity (up to 1,000 MW of the 1,100 MW proposed total). First Wind, in turn, would seek to recover the cost paid for this transmission capacity through the sale of electricity and renewable energy credits. First Wind has four wind projects operating in Maine with the capacity to generate 185 MW; thus significant new capacity is still required to justify a business case for the NEL. As the project is still in the proposal stage, with siting and permitting work requiring two to three years and construction a further three years, it is unlikely the project would be operational before 2017–2018.

Exhibit 37: *Northeast Energy Link*



Source: Company Reports

Earnings Estimates

We are introducing the following estimates:

Table 42: *Emera's Estimates*

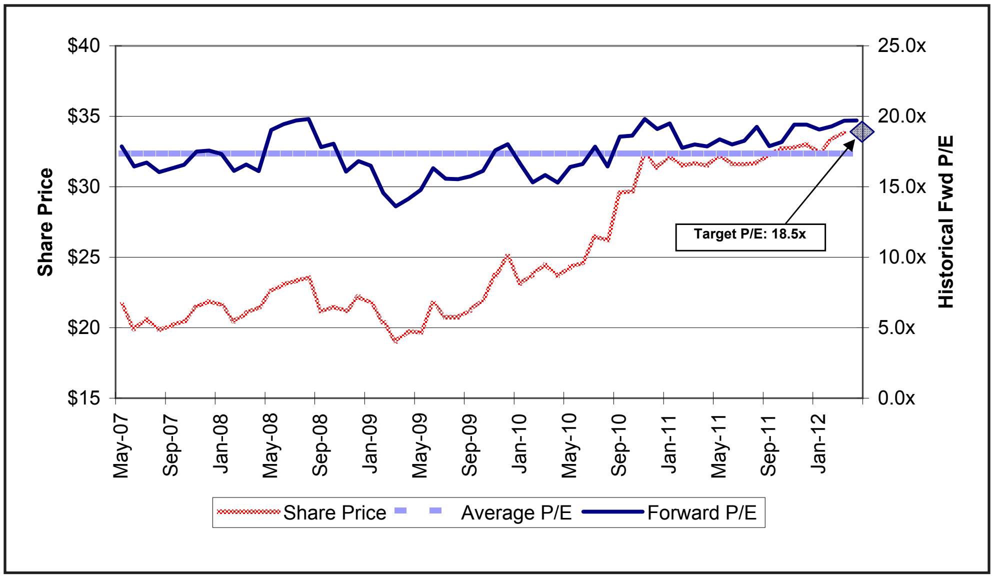
	2012E	2013E
Segmented Earnings		
Nova Scotia Power Inc.	125.2	129.6
Maine Utility Operations	37.1	41.6
Caribbean Utility Operations	21.7	21.7
Brunswick Pipeline	18.5	18.5
Other	10.8	18.1
Total Segmented Earnings	**213.4**	**229.5**
Cash Flow From Operations	**434.4**	**452.5**
Total Capital Expenditures	**623.0**	**530.0**
Average shares o/s (basic)	123.2	123.9
Average shares o/s (diluted)	128.5	128.9
EPS (basic)	**$1.73**	**$1.85**
EPS (diluted)	**$1.72**	**$1.84**
First Call Consensus	***$1.72***	***$1.83***

Source: BMO Capital Markets, Thomson ONE

Valuation – Target Price $34

Our target price of $34 represents 18.5x 2013E EPS, which is toward the upper end of its five-year historical trading range, reflecting strong dividend and earnings growth potential. Provided that its execution performance remains intact, we see little concern from a relative de-rating standpoint

Exhibit 38: *Emera – Forward P/E, Share Price, and Target P/E*



Source: Thomson One, Bloomberg

At current levels, Emera is trading at a P/E of 19.6x in 2012E (vs. 16.1x for our Canadian utility peer group) and 18.3x in 2013E (vs. the peer average at 15.5x). We believe this premium valuation should persist given its strong earnings and dividend growth outlook.

Table 43: *Peer Group Valuation Table*

	Ticker	Price 05-Apr-12	High 52 Wk	Low 52 Wk	12-Month Target	ROR Target	Rating [1]	Shares O/S (mm)	Market Cap. (mm)	EPS 2010A	EPS 2011E	EPS 2012E	EPS 2013E	CAGR ('11-'13)	P/E 2010A	P/E 2011A	P/E 2012E	P/E 2013E	EV/EBITDA 2013E	Dividend Rate [4]	Dividend Yield
Utilities																					
ATCO Ltd. [2]	ACO/X	$70.35	$71.50	$55.34	NA	NA	NR	57.7	$4,061.3	$5.04	$5.70	$6.22	$6.41	6.0%	10.1	10.6	11.3	11.0	NA	$1.31	1.9%
Canadian Utilities Ltd.	CU	$66.12	$68.12	$51.54	$70.00	8.5%	OP	127.6	$8,438.1	$3.32	$3.63	$4.03	$4.13	6.5%	14.2	15.6	16.4	16.0	10.0	$1.77	2.7%
Caribbean Utilities [3]	CUP.U	$9.95	$10.49	$9.01	$9.50	2.1%	Und	28.6	$284.8	$0.67	$0.67	$0.67	$0.70	2.0%	13.0	13.9	14.9	14.3	10.6	$0.66	6.6%
Emera Inc.	EMA	$33.75	$34.92	$19.95	$34.00	4.7%	Mkt	122.2	$4,125.4	$1.65	$1.65	$1.72	$1.84	5.7%	16.1	19.3	19.6	18.3	13.2	$1.35	4.0%
Fortis Inc.	FTS	$32.11	$34.39	$28.24	$34.50	11.2%	OP	188.8	$6,063.8	$1.60	$1.66	$1.74	$1.81	4.4%	18.4	19.7	18.5	17.8	10.6	$1.20	3.7%
Average						**6.6%**								**4.9%**	**14.4**	**15.8**	**16.1**	**15.5**	**11.1**		**3.8%**
Power																					
Boralex Inc.	BLX	$8.00	$9.00	$5.85	$9.00	12.5%	Mkt	37.7	$301.8	($0.15)	($0.07)	($0.07)	($0.29)	nmf	nmf	nmf	nmf	nmf	14.5	$0.00	0.0%
Capital Power Corp.	CPX	$23.40	$28.00	$21.50	$26.00	16.5%	OP	97.2	$2,274.1	$1.40	$1.24	$1.44	$1.64	14.9%	16.3	20.1	16.3	14.3	8.4	$1.26	5.4%
TransAlta Corp.	TA	$18.12	$23.42	$18.25	$19.00	11.3%	Mkt	224.6	$4,070.0	$0.88	$1.04	$1.12	$1.15	5.3%	24.5	20.5	16.1	15.8	8.0	$1.16	6.4%
Average						**13.4%**								**10.1%**	**20.4**	**20.3**	**16.2**	**15.0**	**10.3**		**3.9%**

Notes:
(1) Ratings Key: Outperform – OP; Market Perform – Mkt; Underperform – Und.; Not Rated – NR; Restricted - R
(2) Estimates per First Call
(3) All figures in US Dollars
(4) Recent dividend/distribution annualized
Source: BMO Capital Markets, Thomson One

Risks

- **Regulation:** Nova Scotia Power, Bangor Hydro, and the Caribbean utilities operate in a rate-regulated environment, exposing all utilities to the risk of adverse regulations that can result in earnings below allowed rates. Emera maintains a constructive relationship with each respective utility commission to mitigate this risk.
- **Weather:** Our estimates assume that weather is normal. To the extent that weather is warmer than normal (reducing net residential and commercial demand for electric power for space heating) or colder than normal, actual results will differ from our forecasts.
- **Commodity Prices:** A large portion of the company's fuel supply is sourced from international suppliers and is subject to commodity price risk. While Nova Scotia Power can pass through fuel costs to consumers via the fuel adjustment mechanism over three years, a significant increase in fuel costs (and higher electricity bills) could lead to more contentious regulatory proceedings. We note that the company is hedged for the majority of its fuel purchases for 2012 (94% of coal and 83% of natural gas).
- **Lower Churchill Project:** Emera and Nalcor face a number of environmental, political and regulatory issues before moving forward. Construction risks appear manageable, as Nalcor is responsible for cost overruns on the Muskrat Falls generation facility and the Labrador Island Link Transmission Link, and the company assumes only 50% of overruns on the Maritime Transmission Link.

Emera Inc.'s Management Team

Table 44: *Management Overview*

Name	Position	Employment History
Christopher Huskilson	President and CEO, Emera Inc.	- Mr. Huskilson began his career with Nova Scotia Power in 1980. He was made Chief Operating Officer of Emera and Nova Scotia Power in July 2003 and President and CEO of Emera in 2004.
Scott Balfour	Chief Financial Officer, Emera Inc.	- Mr. Balfour will replace Judy Steele as CFO, effective April 16, 2012. - Mr. Balfour is currently President of Ensimian Capital Corp., a private company providing consulting services and private investment. - Mr. Balfour previously held the position of President and CFO of Aecon Group Inc., a publicly traded construction and infrastructure development company headquartered in Toronto, ON.
Nancy Tower	Executive Vice President of Business Development, Emera Inc. and CEO of Emera Newfoundland and Labrador	- Ms. Tower was appointed to this role on May, 1, 2011. Prior to this, Nancy served as Executive Vice President and Chief Financial Officer for Emera. She has held senior positions at Nova Scotia Power in corporate finance and operations, including Controller and Vice President of Customer Operations.
Rob Bennett	President and CEO, Nova Scotia Power Inc.	- Mr. Bennett began his career with Nova Scotia Power in 1988. He was appointed President and Chief Executive Officer of Nova Scotia Power in June 2008, after serving as Executive Vice President of Revenue and Sustainability. - Before rejoining Nova Scotia Power in September 2007, Mr. Bennett served for two years as President and Chief Operating Officer of Bangor Hydro Electric Company.
Sarah MacDonald	President and CEO of Grand Bahama Power Company	- Ms. MacDonald was appointed President and CEO of Grand Bahama Power Company in June 2011 after serving as Executive Vice President of Human Resources for Emera Inc., Vice President of Human Resources for Nova Scotia Power Inc., and Chief Executive Officer of Emera Utility Services. - Before joining Emera in 2001, Ms. MacDonald worked in employment law, labour relations and human resources, primarily in the health care field.
Robert Hanf	Executive Chairman Light & Power Holdings, Director Barbados Light & Power, Emera Caribbean Limited	- Mr. Hanf was appointed as Executive Chairman LPH and Director BL&P in November 2011. Prior to this, Mr. Hanf served as Chief Legal Officer for Emera Inc., and Chief Executive Officer of Bangor Hydro since 2007. - Mr. Hanf has previously served as General Counsel for Emera and its affiliates since 2002. Prior to Emera, Mr. Hanf was a partner with the law firm McCarthy Tetrault LLP.
Wayne O'Connor	Chief Operating Officer, Emera Energy	- Mr. O'Connor joined Emera in 2003. As Vice-President, Operations for Emera Energy, Mr. O'Connor managed a professional staff of traders and schedulers for both electricity and natural gas. In 2008, he was promoted to Chief Operating Officer, and now has executive responsibility for all aspects of the operation.
Dan Muldoon	President and COO, Emera Utility Services	- Mr. Muldoon was appointed President and Chief Operating Officer of Emera Utility Services in July 2010. He has over 24 years of prior experience with Emera companies. He has held the positions of General Manager of Customer Operations for Nova Scotia Power as well as a number of increasingly senior engineering, supervisory and management positions in both power production and customer operations.
Gerard Chasse	President & Chief Operating Officer, Bangor Hydro Electric Company and Maine Public Service Company	- Mr. Chasse has served as President and Chief Operating Officer of Bangor Hydro since January 2010, and accepted the additional responsibility of President and COO of Maine Public Service in 2011. Prior to his promotion, Mr. Chasse served as Executive Vice President of Operations. - Mr. Chasse joined Bangor Hydro in 1990 as an electrical engineer in the substation engineering department and has held numerous positions of responsibility within the engineering group.

Source: Company Reports

Table 45: *Consolidated Summary Sheet*

	Year Ended December 31									CAGR 2011A-2013E
	2005	2006	2007	2008	2009	2010	2011	2012E	2013E	
Total Earnings Per Share	$1.04	$1.09	$1.24	$1.28	$1.56	$1.68	$1.66	$1.73	$1.85	5.8%
Diluted Earnings Per Share	$1.04	$1.09	$1.22	$1.26	$1.52	$1.65	$1.65	$1.72	$1.84	5.7%
First Call Consensus								*$1.72*	*$1.83*	
Dividends	$0.89	$0.89	$0.90	$0.98	$1.03	$1.16	$1.30	$1.36	$1.41	4.1%
Payout Ratio	85.4%	81.4%	72.3%	76.7%	66.2%	69.1%	78.7%	78.7%	76.2%	
Average Diluted Shares (mm)	123.2	123.9	124.6	124.9	121.3	120.3	126.2	128.5	128.9	
Net Book Value	$12.41	$12.69	$12.20	$13.78	$13.31	$14.19	$11.83	$12.25	$12.74	
Market Valuation										
Price: High	$21.04	$22.91	$22.84	$23.56	$25.49	$32.54	$33.65	-	-	
Price: Low	$17.68	$17.70	$19.20	$18.63	$18.79	$23.10	$28.14	-	-	
Price: Current	-	-	-	-	-	-	-	$33.75	-	
P/E Ratio: High	20.2	21.0	18.8	18.7	16.8	19.7	20.4	-	-	
P/E Ratio: Low	17.0	16.2	15.8	14.8	12.4	14.0	17.0	-	-	
P/E Ratio: Current	-	-	-	-	-	-	-	19.6	18.3	
EV/EBITDA: High	10.5	9.4	9.1	11.5	10.9	13.6	14.2	-	-	
EV/EBITDA: Low	9.6	8.2	8.2	10.3	9.4	11.5	13.0	-	-	
EV/EBITDA: Current	-	-	-	-	-	-	-	13.5	13.1	
Yield: High Price	4.2%	3.9%	3.9%	4.2%	4.1%	3.6%	3.9%	-	-	
Yield: Low Price	5.0%	5.0%	4.7%	5.3%	5.5%	5.0%	4.6%	-	-	
Yield: Current	-	-	-	-	-	-	-	4.0%	4.2%	
Balance Sheet ($mm)										
Debt (S-T)	241.0	136.6	225.6	303.3	424.4	240.8	246.0	322.0	621.9	
Debt (L-T)	1,631.8	1,657.4	1,600.2	2,159.2	2,319.9	3,006.9	3,273.5	3,597.3	3,534.9	
Deferred Items	231.0	231.8	333.2	474.6	481.2	684.0	440.0	440.0	440.0	
Preferred Shares	260.8	260.8	260.8	260.8	135.0	281.7	279.3	279.3	279.3	
Shareholders' Equity	1,366.2	1,408.1	1,359.8	1,546.4	1,503.5	1,626.9	1,452.5	1,513.1	1,582.6	
	3,730.7	3,694.6	3,779.6	4,744.3	4,864.0	5,840.3	5,691.3	6,151.7	6,458.7	
Balance Sheet (%)										
Debt (S-T)	6.5%	3.7%	6.0%	6.4%	8.7%	4.1%	4.3%	5.2%	9.6%	
Debt (L-T)	43.7%	44.9%	42.3%	45.5%	47.7%	51.5%	57.5%	58.5%	54.7%	
Deferred Items	6.2%	6.3%	8.8%	10.0%	9.9%	11.7%	7.7%	7.2%	6.8%	
Preferred Shares	7.0%	7.1%	6.9%	5.5%	2.8%	4.8%	4.9%	4.5%	4.3%	
Shareholders' Equity	36.6%	38.1%	36.0%	32.6%	30.9%	27.9%	25.5%	24.6%	24.5%	
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
Income Statement ($mm)										
Total Revenue	1,168.0	1,166.0	1,339.5	1,331.9	1,465.5	1,553.7	2,064.4	1,542.0	1,607.9	-11.7%
EBITDA	448.3	520.5	545.0	490.6	547.2	548.8	567.5	634.5	668.5	8.5%
EBIT	312.2	375.3	395.7	339.3	382.3	375.2	317.5	425.5	457.5	20.0%
Net Earnings	114.1	120.9	138.1	143.2	175.7	191.1	200.3	213.4	229.5	7.0%
Cash Flow from Operations	278.1	313.2	364.5	317.5	331.3	336.1	439.8	434.4	452.5	1.4%
Key Statistics										
Average Utility Rate Base ($mm)	2,841.4	2,837.3	2,772.2	2,712.1	2,941.0	3,299.5	3,425.4	3,630.2	3,757.2	4.7%
Growth Rate	0.4%	-0.1%	-2.3%	-2.2%	8.4%	12.2%	3.8%	6.0%	3.5%	
Allowed Return on Equity	9.55%	9.55%	9.55%	9.55%	9.35%	9.35%	9.35%	9.20%	9.20%	
Deemed Equity	37.5%	37.5%	37.5%	40.0%	39.5%	39.3%	37.5%	37.5%	37.5%	

Note: Priced as of market close on April 5, 2012.
Source: BMO Capital Markets, Company Reports

Fortis Inc.

Initiating Coverage at Outperform; Your All-Weather Stock

Fortis Inc. (FTS-TSX)
Price: $32.11 (Apr-5-12)
Target: $34.50

Investment Summary

- **We are initiating coverage of Fortis Inc. with an Outperform rating and a $34.50 target price.** Fortis is hardly a market darling these days amid less robust earnings growth and uncertainty regarding its unregulated hydro assets in Belize. We have heard this song before, and while we recognize the market is waiting anxiously for a full resolution of these issues, we would argue that these issues are already priced in. In the meantime, we believe the market should return its attention to the company's sizable $5.5 billion relatively low-risk organic growth initiatives through 2016, which should ultimately bear fruit with the passage of time. Our target price of $34.50 represents 19x 2013E EPS, which is a premium to its peer group and towards the upper end of its five-year historical trading range. We believe the premium is justified given its superior earnings visibility (~90% of Fortis' earnings arise from utility operations, the highest among its peers) and the secular reduction observed in 10-year government of Canada bond yields.
- **The largest and most diversified utility in Canada.** Fortis is Canada's largest and most diversified regulated distribution utility company with over 2,000,000 natural gas and electricity customers across the country. The company also has a small portfolio of real estate holdings and interests in two Caribbean regulated electricity distribution companies. In addition, the company is developing the 335 MW Waneta Dam expansion, a $900 million contracted hydro project (51% owned) that is expected to be commissioned by spring 2015.
- **$5.5 billion of organic growth.** In our opinion, Fortis has an attractive organic project slate totalling $5.5 billion, characterized by intensified capital investment activities in its Western Canada franchise and a 51% share of the $900 million Waneta hydro project, which come together in the 2012–2016 time frame, supporting a two-year diluted earnings CAGR of 4.7% through 2013. At the same time, in order to maintain its premium valuation, in our view, the company must demonstrate continued solid execution capability.
- **Crossing the 49th parallel.** Aside from its organic growth execution scorecard, another key driver for Fortis' share price in the near term is the successful consummation of New York-based utility CH Energy, which still requires approval from CH Energy shareholders (likely summer 2012) and regulators (Q1/13). Fortis has a track record of making accretive acquisitions and its recent failed acquisition attempt for Central Vermont Public Service demonstrates management's discipline in not overpaying for assets. But there appears to be market skepticism in how profitable Fortis will be in uncharted U.S. territories. We currently assume a $500 million common equity issue at the beginning of 2013 to permanently finance the transaction, with estimated accretion

of $0.03 per share. We believe the successful close of CH Energy is an important step in its journey in becoming a North American player and the measured approach Fortis appears to be taking should help diminish the acquisition risk associated with the name. More details on the CH Energy transaction are provided later on.

- **Being paid to wait.** As investors wait to assess the visibility of Fortis' growth pillars, its U.S. acquisition strategy and a full resolution in Belize, a dividend of $1.20 (3.7% yield) is being paid, which we believe is attractive and sustainable given the company's conservative balance sheet consisting of 60% debt and 40% equity (including preferred shares). We also believe there is a reasonable likelihood that Fortis will raise its common share dividend in 2013 to $1.26 per share, which equates to a reasonable 67.2% payout ratio.
- **Earnings estimates.** We are introducing EPS (f.d) forecasts of $1.74 in 2012 and $1.81 in 2013.
- **Relative valuation – premium levels.** At current levels, Fortis is trading at a P/E of 18.5x in 2012E (vs. 16.1x for our Canadian utility peer group) and 17.8x in 2013E (vs. the peer group average at 15.5x).

Exhibit 40: *Fortis at a Glance*

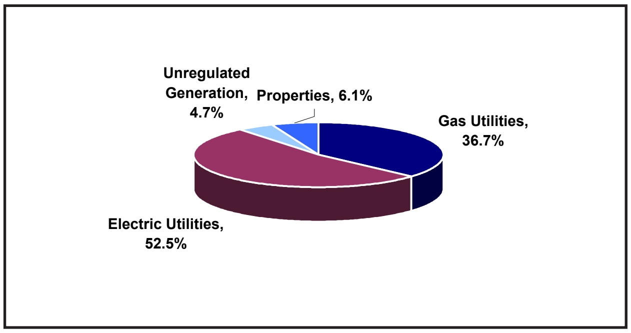
Upcoming Events/Potential Catalysts

End of April 2012	Expected filing of regulatory appplication - CH Energy
May 2, 2012	Q1/12 Results
May 4, 2012	Annual General Meeting
July 31, 2012	Q2/12 Results
Q2/12	Expected regulatory approval of FortisBC Electric's 2012/13 Rates
Summer 2012	CH Energy shareholder approval
1H/2012	Expected regulatory filing of FortisAlberta's 2012/13 Rates
1H/2012	Expected regulatory decision on FortisBC Energy's 2012/13 Rates
Nov. 1, 2012	Q3/12 Results
Late 2012/Early 2013	Expected common equity issue (CH Energy)
Early 2013	Expected closing of CH Energy Transaction
2H/2013	Expected completion of Newfoundland office building
Spring 2015	Expected commissioning of Waneta hydro facility

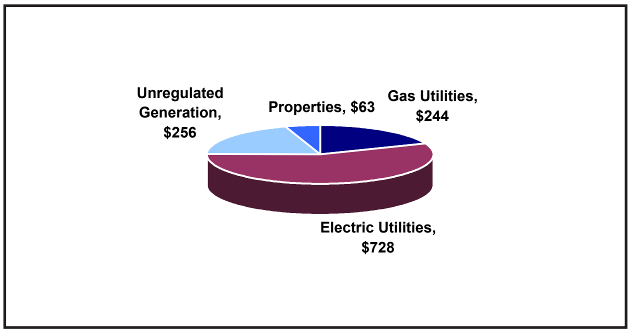
Selected Financing History

Type	Date	Price/Rate	# Shares (mm)	Amount (mm)
Medium Term Note	09-Dec-11	4.25%	na	$100.0
Medium Term Note	19-Oct-11	4.54%	na	$125.0
Common Equity	15-Jun-11	$33.00	9.1	$300.3
Medium Term Note	06-Dec-10	5.20%	na	$100.0
Medium Term Note	24-Nov-10	5.00%	na	$100.0
Medium Term Note	27-Oct-10	4.80%	na	$125.0
Preferred Shares	26-Jan-10	$25.00	10	$250.0
Common Equity	19-Dec-08	$25.65	11.7	$300.1
Medium Term Note	30-Oct-09	5.37%	na	$125.0
Medium Term Note	20-Jul-09	6.51%	na	$200.0
Medium Term Note	02-Jun-09	6.10%	na	$105.0
Common Equity	19-Dec-08	$25.65	11.7	$300.1

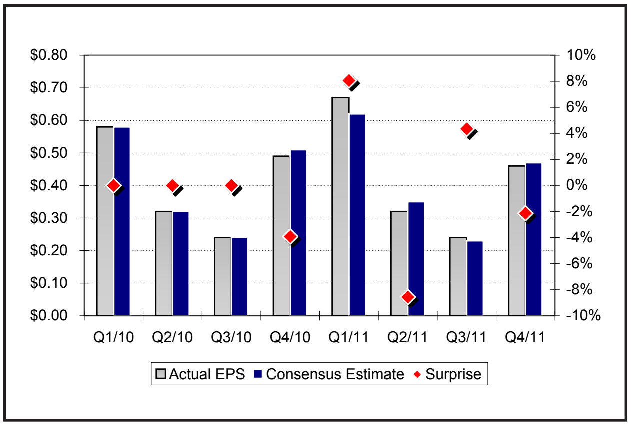
90% of Earnings Are Generated from Regulated Operations



2012E Capital Budget ($mm)

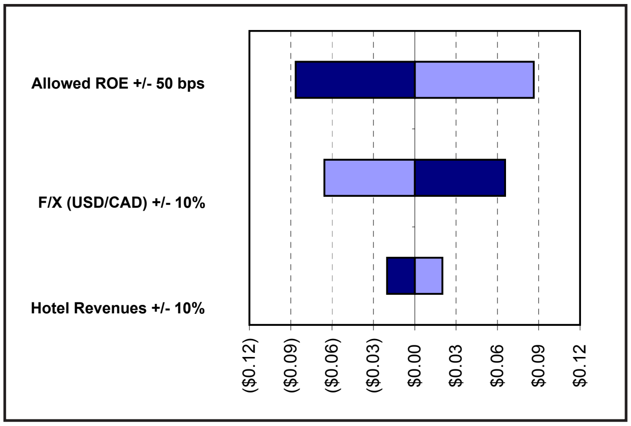


EPS Surprises vs. Consensus



Source: Company Reports, Thomson One

Sensitivities



Source: BMO Capital Markets

Source: BMO Capital Markets, Company Reports

Corporate Overview

Fortis generated earnings (excluding corporate costs) of $379 million in 2011. Table 46 below illustrates the breakdown by key business segment in terms of earnings contribution, total assets, and capital spending.

Table 46: *Key Assets of Fortis*

	Net Earnings (1)	% of Total	Total Assets	% of Total	Gross Capex	% of Total
FortisBC Energy Companies	139.0	36.7%	5,316.0	39.5%	253.0	21.6%
Fortis Alberta	75.0	19.8%	2,679.0	19.9%	416.0	35.4%
FortisBC Electric	48.0	12.7%	1,541.0	11.4%	102.0	8.7%
Newfoundland Power	34.0	9.0%	1,202.0	8.9%	81.0	6.9%
Other Canadian	22.0	5.8%	721.0	5.4%	47.0	4.0%
Electric Caribbean	20.0	5.3%	856.0	6.4%	71.0	6.0%
Fortis Generation	18.0	4.7%	542.0	4.0%	174.0	14.8%
Fortis Properties	23.0	6.1%	614.0	4.6%	30.0	2.6%
Total	**379.0**	**100.0%**	**13,471.0**	**100.0%**	**1,174.0**	**100.0%**

Note: (1) Attributable to common shareholders.
Source: Company Reports, BMO Capital Markets

Earnings Estimates

Our 2012 and 2013 diluted earnings per share estimates of $1.74 and $1.81, respectively, assume the successful close of CH Energy in early 2013.

Table 47: *Fortis' Estimates*

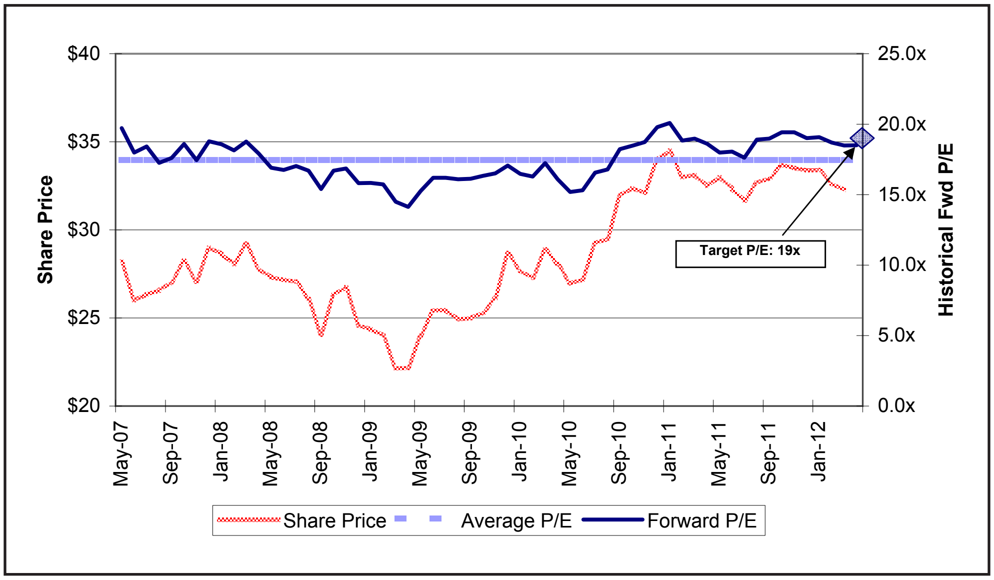
	2012E	2013E
Segmented Earnings		
FortisBC Energy Companies	147.7	150.9
Fortis Alberta	81.5	89.9
FortisBC Electric	49.9	53.0
Newfoundland Power	34.0	35.6
Other Canadian	20.8	21.6
Caribbean	20.3	22.1
Fortis Generation	18.7	18.7
Fortis Properties	25.8	26.6
US Utilities	0.0	44.8
Corporate & Other	(68.2)	(85.3)
Total Segmented Earnings	**330.4**	**378.0**
Cash Flow From Operations	**837.9**	**914.4**
Total Capital Expenditures	**1,291.0**	**2,081.8**
Average shares o/s (basic)	187.9	206.5
Average shares o/s (diluted)	199.7	218.2
EPS (basic)	**$1.76**	**$1.83**
EPS (diluted)	**$1.74**	**$1.81**
First Call Consensus	***$1.75***	***$1.82***

Source: BMO Capital Markets, Thomson ONE

Valuation – Target Price $34.50

Our target price of $34.50 represents 19x 2013E EPS, which is a premium to its peer group and toward the upper end of its five-year historical trading range. We believe the premium is justified given its superior earnings visibility (90% of Fortis' earnings arise from utility operations, the highest among its peers) and the secular reduction observed in 10-year government of Canada bond yields.

Exhibit 41: *Fortis – Forward P/E, Share Price, and Target P/E*



Source: Thomson One, Bloomberg

At current levels, Fortis is trading at a P/E of 18.5x in 2012E (vs. 16.1x for our Canadian utility peer group) and 17.8x in 2013E (vs. the peer group average at 15.5x).

Table 48: *Peer Group Valuation Table*

	Ticker	Price 05-Apr-12	High 52 Wk	Low 52 Wk	12-Month Target	ROR Target	Rating (1)	Shares O/S (mm)	Market Cap. (mm)	EPS 2010A	EPS 2011E	EPS 2012E	EPS 2013E	CAGR ('11-'13)	P/E 2010A	P/E 2011A	P/E 2012E	P/E 2013E	EV/EBITDA 2013E	Dividend Rate (4)	Dividend Yield
Utilities																					
ATCO Ltd. (2)	ACO/X	$70.35	$71.50	$55.34	NA	NA	NR	57.7	$4,061.3	$5.04	$5.70	$6.22	$6.41	6.0%	10.1	10.6	11.3	11.0	NA	$1.31	1.9%
Canadian Utilities Ltd.	CU	$66.12	$68.12	$51.54	$70.00	8.5%	OP	127.6	$8,438.1	$3.32	$3.63	$4.03	$4.13	6.5%	14.2	15.6	16.4	16.0	10.0	$1.77	2.7%
Caribbean Utilities (3)	CUP.U	$9.95	$10.49	$9.01	$9.50	2.1%	Und	28.6	$284.8	$0.67	$0.67	$0.67	$0.70	2.0%	13.0	13.9	14.9	14.3	10.6	$0.66	6.6%
Emera Inc.	EMA	$33.75	$34.92	$19.95	$34.00	4.7%	Mkt	122.2	$4,125.4	$1.65	$1.65	$1.72	$1.84	5.7%	16.1	19.3	19.6	18.3	13.2	$1.35	4.0%
Fortis Inc.	FTS	$32.11	$34.39	$28.24	$34.50	11.2%	OP	188.8	$6,063.8	$1.60	$1.66	$1.74	$1.81	4.4%	18.4	19.7	18.5	17.8	10.6	$1.20	3.7%
Average						**6.6%**								**4.9%**	**14.4**	**15.8**	**16.1**	**15.5**	**11.1**		**3.8%**
Power																					
Boralex Inc.	BLX	$8.00	$9.00	$5.85	$9.00	12.5%	Mkt	37.7	$301.8	($0.15)	($0.07)	($0.07)	($0.29)	nmf	nmf	nmf	nmf	nmf	14.5	$0.00	0.0%
Capital Power Corp.	CPX	$23.40	$28.00	$21.50	$26.00	16.5%	OP	97.2	$2,274.1	$1.40	$1.24	$1.44	$1.64	14.9%	16.3	20.1	16.3	14.3	8.4	$1.26	5.4%
TransAlta Corp.	TA	$18.12	$23.42	$18.25	$19.00	11.3%	Mkt	224.6	$4,070.0	$0.88	$1.04	$1.12	$1.15	5.3%	24.5	20.5	16.1	15.8	8.0	$1.16	6.4%
Average						**13.4%**								**10.1%**	**20.4**	**20.3**	**16.2**	**15.0**	**10.3**		**3.9%**

Notes:
(1) Ratings Key: Outperform – OP; Market Perform – Mkt; Underperform – Und.; Not Rated – NR; Restricted - R
(2) Estimates per First Call
(3) All figures in US Dollars
(4) Recent dividend/distribution annualized
Source: BMO Capital Markets, Thomson One

Proposed Acquisition of CH Energy

On February 21, 2012, Fortis agreed to acquire all of the issued and outstanding shares of CH Energy Group Inc. for US$65/share, which translates into a total purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt. We note the following key details about CH Energy Group and the proposed transaction:

- **Reasonable purchase premium.** The purchase price represents a premium of approximately 10.5% over the closing price of CH Energy Group's common shares prior to the acquisition announcement.
- **Full value paid.** The transaction values CH at approximately 20.2x 2012E EPS, based on estimates provided by Bloomberg.
- **Transaction provides Fortis with a toehold into the U.S. market.** It is expected that Fortis will pursue additional U.S. utility acquisitions in the U.S. given the lack of opportunities in Canada for Fortis to expand its business.
- **Regulated operations consistent with Fortis' current composition.** Approximately 97% of CH Energy Group's 2011 earnings were derived from Central Hudson Gas and Electric Corporation. Central Hudson is a regulated transmission and distribution utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley.
- **Stable regulatory environment.** Central Hudson operates principally under a cost-of-service regulation. The regulatory framework at Central Hudson enables the company to recover fuel, purchased power and transmission costs, along with capital program costs with minimal lag. For the three-year period beginning July 1, 2010, Central Hudson's rates have been established using a 10% ROE and a capital structure of 48% common equity; however, our sense is that given how far U.S. Treasuries have decreased since the last review, allowed ROEs at Central Hudson will likely be rebased lower. We assume a 9.50% allowed ROE in our outlook.
- **Attractive rate base growth expected over the next five years.** Central Hudson's annual capital expenditures are expected to exceed US$100 million on average through 2016.
- **Immediate earnings accretion expected.** We estimate that the acquisition could be approximately $0.03/share accretive once it closes.
- **Equity issuance could increase based on credit rating implications.** The transaction will initially be funded through the use of credit lines; however, we expect that Fortis could issue approximately $500 million of equity to permanently finance the transaction. We note that the size of this offering could increase in light of the recent placement by S&P of Fortis Inc.'s A- corporate credit rating on CreditWatch with Negative Implications from Stable. We believe Fortis is highly committed to its current credit rating and will work to retain it. We also assume Fortis will issue roughly $200 million in preferred shares to support its balance sheet metrics, given that the rating agencies attribute 50% equity treatment to these securities.

- **Customary closing conditions.** Closing of the transaction is expected in the first quarter of 2013, and is subject to regulatory and shareholder approvals.

Risks

- **Regulation:** The company's key business is regulated utilities. Regulated earnings from utility operations in Canada and the Caribbean represent approximately 90% of the company's earnings from operations and, as such, the company is at risk to the potential adverse effect arising from legislative initiatives that alter the governing regulatory compact and/or regulatory decisions. For example, on June 20, 2011, the Government of Belize passed legislation and issued an order to expropriate Fortis' 70% interest in Belize Electricity Limited. We note that Fortis' utility operations are geographically diversified and regulatory arrangements are somewhat different between jurisdictions.

- **Interest Rates:** Although the methodologies used to calculate return on equity allowed by each respective provincial regulator are no longer largely driven upon a forecast of the 30-year Government of Canada bond yield for the prospective fiscal period, we are mindful that the allowed ROE is subject to periodic review and adjustments, particularly in light of the reduction in government bond yields since the last review in 2009. Late last year, the Alberta Utilities Commission lowered the ROE to 8.75% from 9.00%. The British Columbia Utilities Commission has initiated a cost of capital hearing, which could result in a reduction to the 2013 B.C. ROE given that it currently is above 9.5%, one of the highest in Canada. The earnings contribution from regulated utility operations could be negatively effected by lower allowed returns on equity.

Table 49: *Sensitivity of Diluted Earnings per Share to Change in Regulated Metrics*

	2012E	2013E
Newfoundland Power		
100 bps Change in ROE	$0.02	$0.02
100 bps Change in Deemed Equity	$0.00	$0.00
5.00% Change in Rate Base	$0.01	$0.01
FortisAlberta		
100 bps Change in ROE	$0.04	$0.04
100 bps Change in Deemed Equity	$0.01	$0.01
5.00% Change in Rate Base	$0.02	$0.02
FortisBC		
100 bps Change in ROE	$0.02	$0.02
100 bps Change in Deemed Equity	$0.01	$0.01
5.00% Change in Rate Base	$0.01	$0.01
FortisBC Energy		
100 bps Change in ROE	$0.08	$0.08
100 bps Change in Deemed Equity	$0.02	$0.02
5.00% Change in Rate Base	$0.04	$0.04

Source: BMO Capital Markets

- **Hydrology:** The contribution from Fortis Generation is dependent on hydrological conditions. Lower-than-average hydrological conditions in the water sheds that are relevant to the company's facilities are likely to reduce the actual contribution from the generation segment. Hydrology risk is somewhat mitigated by the geographical diversification of the facilities in the portfolio.

- **Foreign Exchange Risk:** The company's earnings from its foreign investments are exposed to changes in U.S. exchange rates. As a result of the company's hedging strategy, the estimated annual sensitivity to each $0.05 increase in the U.S. exchange rate will result in a $0.01 increase in the company's basic earnings per share. Successful consummation of CH Energy and further U.S.-based acquisitions will increase the company's sensitivity to U.S exchange rates.
- **Economic Outlook:** The company's hotel and commercial properties investment is economically sensitive. Approximately 55% of the operating revenues from Fortis Properties are expected to arise from the hotel properties segment. A 10% reduction in revenues from the Hospitality division would reduce earnings by approximately $0.02 per share.

Fortis Inc.'s Management Team

Table 50: *Management Overview*

Name	Position	Employment History
Stanley Marshall	President and Chief Executive Officer of Fortis Inc.	- Mr. Marshall has served in this position since 1995. Currently, Mr. Marshall serves on the Boards of all Fortis Utilities in British Columbia, Ontario, and the Caribbean and the Board of Fortis Properties Corporation. - Mr. Marshall has held a number of roles throughout the organization at Fortis. He joined Newfoundland Power Inc. in 1979.
Barry Perry	Vice President, Finance and Chief Financial Officer of Fortis Inc.	- Mr. Perry has served in this position since 2004. Prior to his current position at Fortis, Mr. Perry held the position of Vice President, Finance and Chief Financial Officer of Newfoundland Power. - Previously, Mr. Perry has held positions as the Vice President Treasurer with a global forest products company and Corporate Controller with a large crude oil refinery.
Ronald McCabe	Vice President, General Counsel and Corporate Secretary of Fortis Inc.	- Mr. McCabe has served in this position since 1997. Prior to this, he practiced corporate law and was in-house counsel to two airlines.
John Walker	President & Chief Executive Officer of FortisBC	- Mr. Walker has worked with the Fortis group of companies since 1983, where he began his career with Newfoundland Power Inc. He also serves on the Board of Directors of the Canadian Electricity Association, Western Energy Institute and Sauder Faculty Advisory Board, University of British Columbia.
Karl Smith	President and Chief Executive Officer of FortisAB	- Appointed President and CEO of FortisAlberta on May - Prior to this appointment Mr. Smith held the position of President and CEO of Newfoundland Power Inc., a position he held from January 2004 to April 2007. - From 1999 until 2003, he was Chief Financial Officer Fortis Inc., from 1995 until 1999 he as was Vice President Finance and CFO of Newfoundland Power Inc. and from 1989 to 1995, Mr. Smith held the positions of Vice President, Finance of Fortis Properties and Fortis Trust Corporation.

Source: Company Reports

Table 51: *Consolidated Summary Sheet*

	Year Ending December 31									CAGR 2011A-2013E
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012E**	**2013E**	
Total Basic Earnings Per Share	$1.17	$1.38	$1.36	$1.60	$1.54	$1.63	$1.67	$1.76	$1.83	4.8%
Total Diluted Earnings Per Share	$1.10	$1.33	$1.29	$1.56	$1.51	$1.60	$1.66	$1.74	$1.81	4.4%
First Call Consensus								*$1.75*	*$1.82*	
Segmented EPS										
Newfoundland Power	$0.29	$0.29	$0.22	$0.20	$0.19	$0.20	$0.19	$0.18	$0.17	
Other Canadian	$0.12	$0.13	$0.11	$0.10	$0.10	$0.11	$0.12	$0.11	$0.10	
Fortis Properties	$0.14	$0.15	$0.15	$0.15	$0.14	$0.15	$0.13	$0.14	$0.13	
Fortis Generation	$0.21	$0.25	$0.17	$0.19	$0.09	$0.12	$0.10	$0.10	$0.09	
Fortis Caribbean	$0.18	$0.23	$0.24	$0.19	$0.15	$0.13	$0.11	$0.11	$0.11	
FortisAlberta	$0.30	$0.40	$0.35	$0.29	$0.35	$0.39	$0.40	$0.43	$0.44	
FortisBC	$0.24	$0.26	$0.23	$0.22	$0.22	$0.24	$0.26	$0.27	$0.26	
Terasen Inc.	$0.00	$0.00	$0.31	$0.71	$0.72	$0.73	$0.77	$0.79	$0.73	
U.S. Utilities	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.22	
Other/Corporate	($0.30)	($0.33)	($0.41)	($0.45)	($0.42)	($0.45)	($0.41)	($0.36)	($0.41)	
Dividends	$0.61	$0.67	$0.82	$1.03	$1.04	$1.12	$1.16	$1.20	$1.24	3.4%
Payout Ratio	52.3%	48.4%	60.2%	64.2%	67.6%	68.9%	69.6%	68.3%	67.7%	
Average Shares (mm)	101.8	103.6	137.6	157.4	170.2	172.9	181.6	187.9	206.5	
Net Book Value	$11.76	$12.26	$16.72	$18.00	$18.64	$18.95	$20.73	$21.38	$22.88	
Market Valuation										
Price: High	$25.64	$30.00	$30.00	$29.94	$28.86	$34.20	$35.15	-	-	
Price: Low	$17.00	$20.36	$24.50	$20.70	$21.62	$25.67	$32.67	-	-	
Price: Current	-	-	-	-	-	-	-	$32.11	-	
P/E Ratio: High	23.3	22.5	23.3	19.2	19.1	21.3	21.2	-	-	
P/E Ratio: Low	15.4	15.3	19.0	13.2	14.3	16.0	19.7	-	-	
P/E Ratio: Current	-	-	-	-	-	-	-	18.5	17.8	
EV/EBITDA: High	10.5	12.3	12.5	10.4	10.9	11.3	11.5	-	-	
EV/EBITDA: Low	8.7	10.4	11.6	9.1	9.8	10.0	11.1	-	-	
EV/EBITDA: Current	-	-	-	-	-	-	-	10.5	10.4	
Yield: High Price	2.4%	2.2%	2.7%	3.4%	3.6%	3.3%	3.3%	-	-	
Yield: Low Price	3.6%	3.3%	3.3%	5.0%	4.8%	4.4%	3.6%	-	-	
Yield: Current	-	-	-	-	-	-	-	3.7%	3.9%	
Balance Sheet ($mm)										
Debt (S-T)	80.3	182.5	911.0	650.0	639.0	414.0	265.0	257.2	408.9	
Debt (L-T)	2,133.8	2,494.5	4,578.0	4,840.0	5,237.0	5,565.0	5,679.0	6,100.0	7,156.1	
Minority Interest	39.6	130.0	115.0	145.0	123.0	162.0	208.0	208.0	208.0	
Preferred Shares	319.5	442.0	442.0	667.0	667.0	912.0	912.0	912.0	1,112.0	
Convertible Debentures	22.3	63.5	45.0	44.0	44.0	44.0	0.0	0.0	0.0	
Shareholders' Equity	1,213.4	1,275.7	2,600.7	3,045.7	3,192.7	3,305.0	3,877.0	4,038.2	4,724.3	
	3,808.8	4,588.1	8,691.7	9,391.7	9,902.7	10,402.0	10,941.0	11,515.4	13,609.2	
Balance Sheet (%)										
Debt (S-T)	2.1%	4.0%	10.5%	6.9%	6.5%	4.0%	2.4%	2.2%	3.0%	
Debt (L-T)	56.0%	54.4%	52.7%	51.5%	52.9%	53.5%	51.9%	53.0%	52.6%	
Minority Interest	1.0%	2.8%	1.3%	1.5%	1.2%	1.6%	1.9%	1.8%	1.5%	
Preferred Shares	8.4%	9.6%	5.1%	7.1%	6.7%	8.8%	8.3%	7.9%	8.2%	
Convertible Debentures	0.6%	1.4%	0.5%	0.5%	0.4%	0.4%	0.0%	0.0%	0.0%	
Shareholders' Equity	31.9%	27.8%	29.9%	32.4%	32.2%	31.8%	35.4%	35.1%	34.7%	
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
Income Statement										
Total Revenue	1,422.2	1,460.1	2,720.4	3,903.0	3,636.0	3,664.0	3,731.5	3,744.0	4,560.4	10.6%
EBITDA	495.9	521.1	816.4	1,061.0	1,063.0	1,150.0	1,169.5	1,291.8	1,490.5	12.9%
EBIT	338.2	343.6	543.4	713.0	704.0	736.0	750.5	848.5	994.1	15.1%
Net Earnings	119.2	143.2	187.4	252.5	262.0	281.0	302.5	330.4	378.0	11.8%
Cash Flow from Operations	329.2	316.3	490.0	622.0	678.0	734.0	795.0	837.9	914.4	7.2%

Note: Priced as of market close on April 5, 2012.
Source: BMO Capital Markets, Company Reports

TransAlta

Initiating Coverage at Market Perform; Repositioning for the Long Term

TransAlta (TA-TSX)
Price: $18.12 (Apr-5-12)
Target: $19.00

Investment Summary

- **We are initiating coverage of TransAlta with a Market Perform rating and a $19 target price.** TransAlta's strategy to reposition its coal assets, improve base operations and green its portfolio should ultimately translate into more stable performance, but depressed gas/power prices in the Pacific Northwest and the ongoing Sundance 1/2 saga will likely place a damper on near-term stock performance. Our $19 target price for TA is based on 8.5x 2013E EV/EBITDA, a 1.5x reduction from its five-year average.
- **The largest independent power producer in Canada.** TransAlta is Canada's largest independent power producer, with 8,396 MW of owned net generating capacity (Table 57). Coal-fired facilities still make up approximately more than half of the company's portfolio, but it also has a sizable renewable power portfolio of over 2,000 MW. The company also has an energy trading segment that manages price and operational risk.
- **A lot has changed over the last 10 years.** For the early part of the last decade, TransAlta had been able to redeploy cash flow from the sale of its regulated electric business and from its high-margin Alberta-based coal assets into investments around the world, including Washington, California and elsewhere. Nonetheless, over the last few years, energy market conditions and the reliability of its coal generating fleet have shifted radically. Environmental regulation could effectively shorten the expected useful lives of TransAlta's core coal assets (52% of total capacity), and power prices remain depressed in the Pacific Northwest, where the company's 1,340 MW Centralia coal plant sells its output. Perhaps most importantly, the Sundance 1 and 2 dispute remains in arbitration, with a resolution not likely until at least July 2012. While there are no clear immediate answers, we view the next 12–18 months as a pivotal phase for TransAlta with the very real possibility that if energy markets in the Pacific Northwest do not recover, the company could face a sharp drop in earnings and cash flow.
- **Priorities for 2012.** Although Dawn Farrell, TransAlta's new CEO, has been at the helm for only a few months, we believe the market is highly focused on the execution of her strategic goals. We believe her goals are achievable and could result in sustainable growth. But in the context of a less flexible balance sheet and with an aging coal fleet serially ambushed by unscheduled maintenance, we may not see tangible results in the near term. At the 2011 investor day, the message that rang loud and clear was that TransAlta would like more consistent fleet availability and that it wanted to maintain a strong balance sheet. In our view, TransAlta's success with this strategy is not optional and time is limited with above-market hedges rolling off in 2013 at Centralia, which contributed 18% to 2011 operating margins. From our standpoint, the priorities for 2012 revolve around:

- **Major maintenance:** On the heels of the shutdown of Sundance 1 and 2 in early 2011, TransAlta plans to invest significant capital in its coal fleet during 2012 to ensure all units meet expected performance targets to the end of useful life. The following facilities are expected to undergo outages this year: Sundance 3, Sundance 5, Keephills 1, Keephills 2, Genesee 3, Sheerness and Centralia. Operationally, TransAlta is targeting 89–90% availability, 5% lower OM&A costs and major maintenance cost for a coal outage of $30 million or less by 2015.
- **Near-term growth.** Aside from 61 MW of coal uprates and the 68 MW New Richmond wind farm, perhaps the most exciting piece of TransAlta's development portfolio is its Sundance 7 gas-fired development, which could add 700 MW in the 2016 time frame. While full approval is not expected until the end of 2012, TransAlta pointed toward a $1.2–1.4 billion cost. Technology and configuration are complete, while customer contracts and fuel supply procurement remain to be secured.
- **Signing contracts at Centralia:** In Washington, TransAlta's most important initiative is to re-contract the Centralia facility. New legislation permits TransAlta to sign long-term contracts with regulated utilities. However, extremely low power prices in the Pacific Northwest, caused by a combination of above-average hydrology (135% of long-term norms) and low natural gas prices, have delayed the company's ability to enter into long-term contracts. TransAlta expects to resume negotiations with utilities in Washington State in mid-2012. Success in signing contracts could result in contract prices above forward markets.

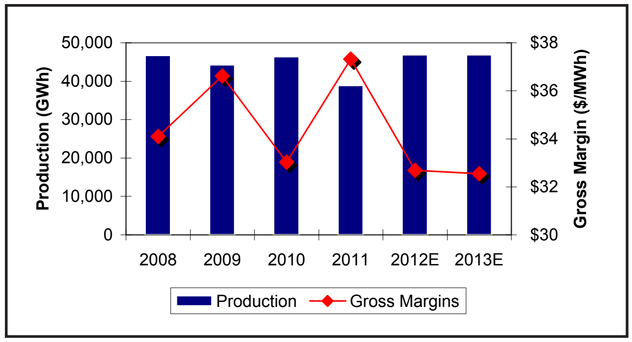
- **Dividend of ~6% should support share price.** We believe the dividend may provide a price floor for the stock so long as the dividend is not perceived to be at risk due to poor cash flow performance. This is not a strategy we advocate, as it tends to overlook the price and operating risks associated with the company's actual performance and strategy. We have not assumed any dividend growth over the forecast period, given an average expected payout ratio of roughly 105%, but note that the cash dividend coverage ratio for 2013E is 3.9x.
- **Hedging.** On the risk management front, TransAlta's total portfolio is hedged 86% for 2012, 78% for 2013, 73% for 2014 and 67% for 2015. Estimated production not subject to long-term contracts has been hedged at rates of $60–65/MWh in Alberta and US$50–55/MWh in the Pacific Northwest. Hedged prices for the periods beyond 2012 are not disclosed.
- **Earnings estimates.** We are introducing EPS forecasts of $1.12 in 2012 and $1.15 in 2013.
- **Relative valuation.** At current levels, TransAlta is trading at 8.0x 2013E EV/EBITDA (vs. 8.4x for CPX).

Exhibit 43: *TransAlta at a Glance*

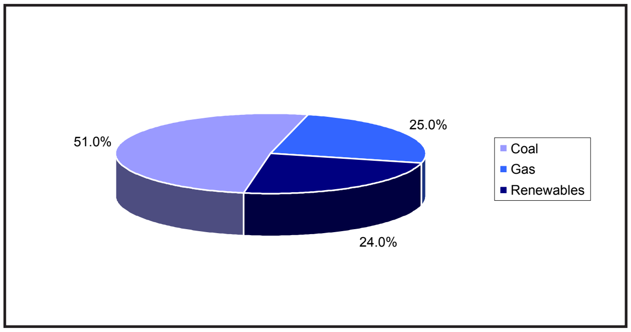
Upcoming Events/Potential Catalysts

April 2012	Q1/12 Results
April 2012	Arbitration hearing on Sundance 1/2 dispute
April 26, 2012	Annual General Meeting
Q2 2012	Expected completion of Keephills Unit 2 uprate
Summer 2012	Final Federal environmental rules for coal-fired generation
Mid-2012	Recommencing negotiations with Washington State (Centralia)
July 2012	Arbitration ruling on Sundance 1/2 dispute
July 2012	Q2/12 Results
Q3 2012	Expected completion of Keephills Unit 1 uprate
Oct. 2012	Q3/12 Results
Q4 2012	Expected completion of New Richmond wind farm
Q4 2012	Expected completion of Sundance Unit 3 uprate
Late 2012	Arbitration ruling on Sundance 3
Late 2012	Sanctioning of Sundance 7

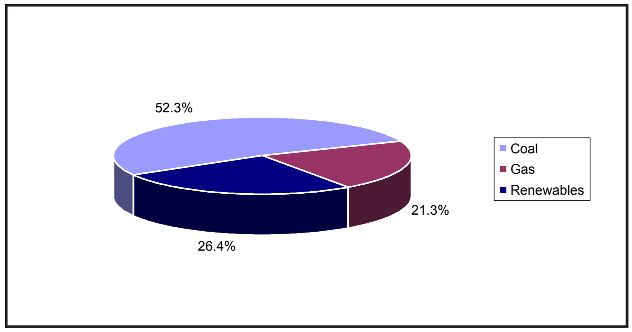
TransAlta - Production and Gross Margins



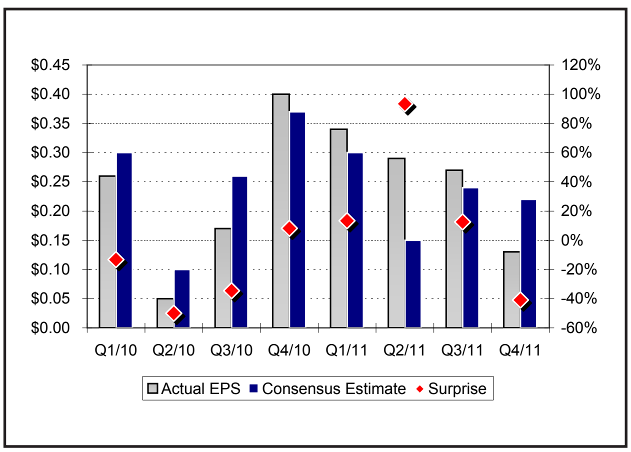
TransAlta - 2011 Gross Margin by Fuel Type



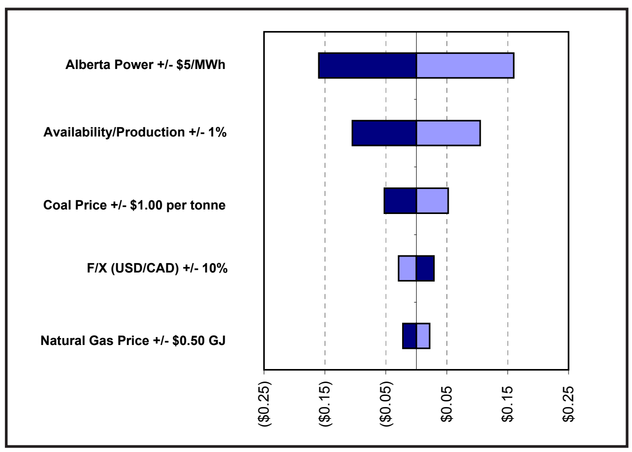
TransAlta - 2011 Net Capacity by Fuel Type (MW)



Consensus vs. Estimates



Sensitivities



Source: Company Reports, Thomson One

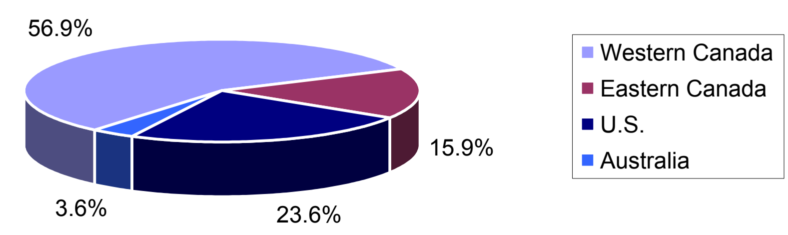
Source: BMO Capital Markets

Source: BMO Capital Markets, Company Reports

Corporate Overview

TransAlta has a net installed capacity of 8,386 MW (includes capacity under equity interest and finance lease) distributed across six coal projects (4,386 MW), 12 natural gas facilities (1,788 MW), 28 hydro (919 MW), 16 wind (1,129 MW) and several geothermal plants (164 MW). While Canada is a significant market for TransAlta, roughly 27% of capacity is based outside of Canada.

Exhibit 44: *TransAlta – 2011 Net Capacity by Geography (MW)*



Source: Company Reports, BMO Capital Markets

Earnings Estimates

We are introducing the following estimates for 2012 and 2013.

Table 52: *TransAlta Estimates*

	2012E	2013E
Revenue	**2,601.5**	**2,582.5**
Fuel and Purchased Power	992.8	982.3
Gross Margin	**1,608.6**	**1,600.2**
% of revenue	61.8%	62.0%
EBITDA	**1,082.9**	**1,076.4**
% of revenue	41.6%	41.7%
EBIT	**565.5**	**551.1**
% of revenue	21.7%	21.3%
Net Earnings Attributable to Common Shareholders	**253.2**	**262.5**
% of revenue	9.7%	10.2%
Average shares o/s (basic & diluted)	225.2	228.5
EPS (basic & diluted)	$1.12	$1.15
First Call Consensus	*$1.11*	*$1.17*
CFPS (basic & diluted)	$3.82	$3.82

Source: BMO Capital Markets, Thomson ONE

Valuation – Target Price $19

We value TransAlta shares using a target EV/EBITDA multiple and support this valuation with secondary measures. For TransAlta, our $19 target price is based on 8.5x 2013E EV/EBITDA, a 1.5x reduction from its five-year average of 10x. Since 2005, the shares have traded at an average EV/EBITDA valuation range of 8.0–11.9x. We believe TransAlta should trade at the lower end of its historical range given depressed gas/power prices in the Pacific Northwest and the ongoing Sundance 1/2 saga. These headwinds could limit earnings growth over our forecast period. Our target price implies a yield of 6.1% and 16.5x our 2013 earnings estimate.

Although we use a multiple of EBITDA as our dominant approach to value TA shares, there are a number of secondary measures we use to support our valuation:

- **Net Asset Value.** As shown in Table 53, we have calculated a $19.50 share price based on observed average transaction prices paid by fuel type.

Table 53: *Price by Fuel Type*

Fuel Type	Transaction Price ($/kW) (1)	Net MW	Estimated Value ($mm)
Coal (2)	900.00	4,386.00	3,947.4
Gas	600.00	1,788.00	1,072.8
Geothermal	1,900.00	164.00	311.6
Hydro	2,000.00	919.00	1,838.0
Wind (3)	1,800.00	1,129.00	2,032.2
Total			**9,202.0**
Less: Total Debt			(4,037.0)
Plus: Cash and Equivalents			49.0
Net Debt			**(3,988.0)**
Non-controlling Interest			(358.0)
Prefered Shares			(569.0)
Net Equity Value			4,287.0
Shares Outstanding			222.0
M&A Transaction Value			**$19.31**

Note:
(1) Price per kW based on 411 transactions from April 1996 to Jan 2012
(Coal - 68, Gas - 233, Geothermal - 14, Hydro - 67 and Wind -29)
(2) Includes 15 MW uprate at Sundance and 23 MW uprates at Keephills 1 and 2 expected to be in-service in 2012
(3) Includes New Richmond (68 MW) project, which is currently under construction
Source: BMO Capital Markets, Company Reports

- **Constant growth dividend growth model.** This approach resides in conventional financial theory, and suggests that the value of the stock is equal to the dividend per share discounted by the difference between the required return on the stock and the dividend growth rate (Dividend/(Required Rate of Return less Dividend Growth Rate). Our key assumptions include a required rate of return of 7.27%, which is determined based on a beta (average pricing of last two years) of 0.61, a 3% risk-free rate and a 7% equity risk premium. Given a payout ratio of over 100%, this implies there is limited dividend growth for TransAlta, but for our analysis we assume a growth rate of 1%, with the resulting value per share of $18.50. If we assume no dividend growth, we calculate a price of ~$16.

- **Implied price to earnings multiple approach.** This approach calculates the implied price-to-earnings multiple that should be used to value a stock based on the estimated earnings retention rate, the required rate of return on the stock and the return on equity reinvested for growth. As set out in Table 54, the implied price to earnings multiple based on our assumptions is approximately 14.4, resulting in a target price of $16.50 per share.

Table 54: *Implied Price to Earnings Multiple Approach*

Estimated EPS 2013	$1.15
Earnings Retention Rate	10%
Required Rate of Return on Stock	7.27%
Return on Equity	10%
Implied Price to Earnings Ratio	14.4x
Implied Price of Stock (P/E x 2013E)	**$16.51**

Source: BMO Capital Markets

- **Peer Group:** At current levels, TransAlta is trading at 8.0x 2013E EV/EBITDA (vs. 8.4x for CPX).

Table 55: *Peer Group Valuation Table*

	Ticker	Price 05-Apr-12	High 52 Wk	Low 52 Wk	12-Month Target	ROR Target	Rating [1]	Shares O/S (mm)	Market Cap. (mm)	EPS 2010A	EPS 2011E	EPS 2012E	EPS 2013E	CAGR ('11-'13)	P/E 2010A	P/E 2011A	P/E 2012E	P/E 2013E	EV/EBITDA 2013E	Dividend Rate [4]	Dividend Yield
Utilities																					
ATCO Ltd. [2]	ACO/X	$70.35	$71.50	$55.34	NA	NA	NR	57.7	$4,061.3	$5.04	$5.70	$6.22	$6.41	6.0%	10.1	10.6	11.3	11.0	NA	$1.31	1.9%
Canadian Utilities Ltd.	CU	$66.12	$68.12	$51.54	$70.00	8.5%	OP	127.6	$8,438.1	$3.32	$3.63	$4.03	$4.13	6.5%	14.2	15.6	16.4	16.0	10.0	$1.77	2.7%
Caribbean Utilities [3]	CUP.U	$9.95	$10.49	$9.01	$9.50	2.1%	Und	28.6	$284.8	$0.67	$0.67	$0.67	$0.70	2.0%	13.0	13.9	14.9	14.3	10.6	$0.66	6.6%
Emera Inc.	EMA	$33.75	$34.92	$19.95	$34.00	4.7%	Mkt	122.2	$4,125.4	$1.65	$1.65	$1.72	$1.84	5.7%	16.1	19.3	19.6	18.3	13.2	$1.35	4.0%
Fortis Inc.	FTS	$32.11	$34.39	$28.24	$34.50	11.2%	OP	188.8	$6,063.8	$1.60	$1.66	$1.74	$1.81	4.4%	18.4	19.7	18.5	17.8	10.6	$1.20	3.7%
Average						**6.6%**								**4.9%**	**14.4**	**15.8**	**16.1**	**15.5**	**11.1**		**3.8%**
Power																					
Boralex Inc.	BLX	$8.00	$9.00	$5.85	$9.00	12.5%	Mkt	37.7	$301.8	($0.15)	($0.07)	($0.07)	($0.29)	nmf	nmf	nmf	nmf	nmf	14.5	$0.00	0.0%
Capital Power Corp.	CPX	$23.40	$28.00	$21.50	$26.00	16.5%	OP	97.2	$2,274.1	$1.40	$1.24	$1.44	$1.64	14.9%	16.3	20.1	16.3	14.3	8.4	$1.26	5.4%
TransAlta Corp.	TA	$18.12	$23.42	$18.25	$19.00	11.3%	Mkt	224.6	$4,070.0	$0.88	$1.04	$1.12	$1.15	5.3%	24.5	20.5	16.1	15.8	8.0	$1.16	6.4%
Average						**13.4%**								**10.1%**	**20.4**	**20.3**	**16.2**	**15.0**	**10.3**		**3.9%**

Notes:
(1) Ratings Key: Outperform – OP; Market Perform – Mkt; Underperform – Und.; Not Rated – NR; Restricted - R
(2) Estimates per First Call
(3) All figures in US Dollars
(4) Recent dividend/distribution annualized
Source: BMO Capital Markets, Thomson One

Investment Risks

TransAlta shares are subject to the following risks:

1. **Operating Risk:** The generation of electricity is a highly mechanical process. All of the company's facilities must be properly maintained if they are to continue to operate in a manner consistent with that implied in our estimates.

2. **Risk of an Unplanned Outage:** Power plants, merchant or otherwise, do not produce power 100% of the time. Contractual arrangements must reflect physical plant limitations, planned outages (maintenance, periodic overhauls and other "foreseen" events) and unanticipated plant outages. In these instances, it is important to understand whether the company is obligated pursuant to the contract to provide replacement power to satisfy contractual arrangements. Where this is the case, the purchase of replacement power in potentially adverse market conditions could result in margin compression. The Power Purchase Arrangement governing each of the Alberta coal-fired generation facilities contains a target availability requirement. The company is assessed a revenue penalty or incentive payment based on whether actual PPA production is less than or greater than the target availability for each unit. These payments are based on a price equal to the 30-day trailing average of the Alberta market electricity price per MWh. These penalties/incentives are notionally designed to ensure that the owner of the PPA facility does not have an incentive to withhold physical production in order to increase market price. We have assumed that the facilities are able to meet their delivery obligations under normal operating conditions.

3. **Counterparty Risk:** The stability of forecast earnings is dependent on the willingness and ability of TransAlta's contract counterparties to honour their contractual commitments. This is particularly important when the agreed-to price per MWh of power production and/or capacity is higher than prevailing prices in organized spot power or bilateral contract markets for both energy and capacity.

4. **Commodity Price Risk:** TransAlta's financial performance is subject to changes in certain commodity prices, including the market and contract prices of electricity and the cost of fuel used to produce electricity. To mitigate this risk, the company has a hedging policy in place based on a four-year ladder structure where contracted merchant capacity in any given year consists of contracts struck during the previous four years. The company does not specify a target contract term; however, we believe that the average term of the contracts governing the portfolio is declining, particularly as the company advances through the term of the PPAs.

5. **Foreign Currency Risk:** Approximately 24% of annual estimated revenue in 2012 and 2013 is derived from assets located outside of Canada. Although the company maintains foreign currency forward contracts to offset the movement in foreign exchange rates in the U.S. and Australia, hedging cannot eliminate foreign currency movements over the long term.

6. **Environment:** In total, coal generation represents approximately 52% of the company's power generation portfolio and this is significant, as the likelihood of legislative initiatives to address the environmental footprint of these facilities has increased substantially.

The timing and quantum of these amounts is not yet known, although some clarity has emerged regarding environmental policy for Centralia (phase-out to 2025) and its Alberta plants (greater of 45 years and expiry of PPA). No capital expenditures are presently reflected in our outlook that are associated with addressing the company's portion of GHG responsibilities in Canada or globally.

TransAlta's Management Team

Table 56: *Management Overview*

Name	Position	Employment History
Dawn Farrell	President and Chief Executive Officer	- Prior to being apointed CEO, Mrs. Farrell served as Chief Operations Officer from 2009 to 2011. - Mrs. Farrell has over 25 years of experience in the electric energy industry, holding roles at TransAlta and BC Hydro. - She has served as Executive VP, Commercial Operations and Development, Executive VP, Corporate Development, Executive VP, Independent Power Projects; and VP, Energy Marketing and IPP Development at TransAlta.
Brett Gellner	Chief Financial Officer	- Prior to joining TransAlta in 2008, Mr. Gellner worked as co-head of CIBC World Markets' Power & Utilities group. - Prior to joing CIBC, he held senior roles in the M&A and Corporate Development groups of a large, publicly traded company, and with a major international consulting firm.
Paul Taylor	President, U.S. Operations	- Mr. Taylor's public sector experience includes serving as Chief of Staff to the Premier of British Columbia, BC's Deputy Minister of Finance and Secretary to the Treasury Board and President and CEO of the Insurance Corp. of BC. Mr. Taylor was responsible for the company's entry into the U.S. northwest power market with the purchase of the Centralia power plant. He left TransAlta in the late 1990s and rejoined this past year.
Ken Stickland	Chief Legal and Business Development Officer	- Prior to joining TransAlta in January 2001, Mr. Strickland was a partner with the Calgary Law firm of Burnet, Duckworth and Palmer LLP where he practiced in the energy area for 20 years.
Dawn de Lima	Chief Human Resources Officer and Executive Vice-President, Communications	- Prior to joining TransAlta in 2006, Ms. de Lima spent nearly two decades involved in human resources as a business leader and has held senior positions in Bell Canada and Norigen Communications.
Rob Schaefer	Executive Vice President, Corporate Development	- Mr. Schaefer started his career in finance and immediately prior to joining TransAlta was CFO of Resin Systems, Inc. He has over 15 years of experience in the energy business.
Cynthia Johnston	Executive Vice President, Corporate Services	- Ms. Johnston has more than 25 years of electric industry experience and returned to TransAlta in late 2009 after five years with FortisAlberta Inc. where she had several vice-presidential roles overseeing regulatory and legal affairs as well as customer and corporate services.
Hugo Shaw	Executive Vice President, Operations	- Mr. Shaw has over two decades of experience in the power industry with a number of public, private and project development companies. Most recently, Mr. Shaw served as TransAlta's Vice President, Coal Operations and Engineering Services.
Robert Emmott	Chief Engineer	- Mr. Emmott has held senior engineering and technical management positions in the Royal Navy and Alstom.
William D.A. Bridge	Executive VP, Business Development	- Mr. Bridge has held a variety of roles within TransAlta including Executive VP Generation Technology, VP Operations, VP Commercial Management, and VP, Corporate Development. - Prior to joining TransAlta, he worked with BC Hydro's subsidiary, Powerex.
David Koch	VP, Controller	- Mr. Koch joined TransAlta in 2003 and has held several finance leadership roles withing the company. - Prior to joining TransAlta, Mr. Koch was Director of Finance for Telus Mobility, and held several finance roles with Agricore.
Maryse C. C. St.-Laurent	VP & Corporate Secretary	- Prior to joining TransAlta, Ms. St.-Laurent was Secretary of TransCanada Pipelines, L.P. since September 2003, recording Secretary since 2001 and Senior Legal Counsel of TransCanada Corp. since 1997.
Todd Stack	Treasurer	- Joined the company in 1990 and has held numerous roles in engineering and finance. - Prior to his current role, he acted as Assistant Treasurer and Director of Treasury.

Source: Company Reports

Plant Summary

TransAlta's assets by geographic region are set out in Table 57.

Table 57: *Assets by Geographic Region*

Facility	Location	Fuel Type	Capacity (MW)	Ownership (%)	Net Capacity (MW)	Revenue Source	Contract Expiry Date
Sundance	AB	Coal	1,581.0	100.0%	1,581.0	Alberta PPA/Merchant	2020
Keephills	AB	Coal	812.0	100.0%	812.0	Alberta PPA/Merchant	2020
Keephills 3	AB	Coal	450.0	50.0%	225.0	Merchant	n/a
Genesee 3	AB	Coal	466.0	50.0%	233.0	Merchant	n/a
Sheerness	AB	Coal	780.0	25.0%	195.0	Alberta PPA	2020
Poplar Creek	AB	Gas	356.0	100.0%	356.0	LTC/Merchant	2024
Fort Saskatchewan	AB	Gas	118.0	30.0%	35.4	LTC	2019
Brazeau	AB	Hydro	355.0	100.0%	355.0	Alberta PPA	2020
Big Horn	AB	Hydro	120.0	100.0%	120.0	Alberta PPA	2020
Spray	AB	Hydro	103.0	100.0%	103.0	Alberta PPA	2020
Ghost	AB	Hydro	51.0	100.0%	51.0	Alberta PPA	2020
Rundle	AB	Hydro	50.0	100.0%	50.0	Alberta PPA	2020
Cascade	AB	Hydro	36.0	100.0%	36.0	Alberta PPA	2020
Kananaskis	AB	Hydro	19.0	100.0%	19.0	Alberta PPA	2020
Bearspaw	AB	Hydro	17.0	100.0%	17.0	Alberta PPA	2020
Pocaterra	AB	Hydro	15.0	100.0%	15.0	Alberta PPA	2020
Horseshoe	AB	Hydro	14.0	100.0%	14.0	Alberta PPA	2020
Barrier	AB	Hydro	13.0	100.0%	13.0	Alberta PPA	2020
Taylor Hydro	AB	Hydro	13.0	100.0%	13.0	Merchant	n/a
Interlakes	AB	Hydro	5.0	100.0%	5.0	Alberta PPA	2020
Belly River	AB	Hydro	3.0	100.0%	3.0	Merchant	n/a
Three Sisters	AB	Hydro	3.0	100.0%	3.0	Alberta PPA	2020
Waterton	AB	Hydro	3.0	100.0%	3.0	Merchant	n/a
St. Mary	AB	Hydro	2.0	100.0%	2.0	Merchant	n/a
Upper Mamquam	BC	Hydro	25.0	100.0%	25.0	LTC	2025
Pingston	BC	Hydro	45.0	50.0%	22.5	LTC	2023
Bone Creek	BC	Hydro	19.0	100.0%	19.0	LTC	2031
Akolkolex	BC	Hydro	10.0	100.0%	10.0	LTC	2015
Summerview 1	AB	Wind	70.0	100.0%	70.0	Merchant	n/a
Summerview 2	AB	Wind	66.0	100.0%	66.0	Merchant	n/a
Ardenville	AB	Wind	69.0	100.0%	69.0	Merchant	n/a
Blue Trail	AB	Wind	66.0	100.0%	66.0	Merchant	n/a
Castle River	AB	Wind	44.0	100.0%	44.0	Merchant	n/a
McBride Lake	AB	Wind	75.0	50.0%	37.5	LTC	2023
Soderglen	AB	Wind	71.0	50.0%	35.5	Merchant	n/a
Cowley Ridge	AB	Wind	21.0	100.0%	21.0	Merchant	n/a
Cowley North	AB	Wind	20.0	100.0%	20.0	Merchant	n/a
Sinnott	AB	Wind	7.0	100.0%	7.0	Merchant	n/a
Macleod Flats	AB	Wind	3.0	100.0%	3.0	Merchant	n/a
Total Western Canada			**5,996.0**		**4,774.9**		
Sarnia Regional	ON	Gas	506.0	100.0%	506.0	LTC	2022-2025
Mississauga	ON	Gas	108.0	50.0%	54.0	LTC	2017
Ottawa	ON	Gas	68.0	50.0%	34.0	LTC	2012
Windsor	ON	Gas	68.0	50.0%	34.0	LTC/Merchant	2016
Ragged Chute	ON	Hydro	7.0	100.0%	7.0	Merchant	n/a
Misema	ON	Hydro	3.0	100.0%	3.0	LTC	2027
Galetta	ON	Hydro	2.0	100.0%	2.0	LTC	2031
Appleton	ON	Hydro	1.0	100.0%	1.0	LTC	2031
Moose Rapids	ON	Hydro	1.0	100.0%	1.0	LTC	2031
Wolfe Island	ON	Wind	198.0	100.0%	198.0	LTC	2029
Melancthon	ON	Wind	200.0	100.0%	200.0	LTC	2026-2028
Le Nordais	QC	Wind	99.0	100.0%	99.0	LTC	2033
Kent Hills	NB	Wind	150.0	83.0%	124.5	LTC	2033-2035
New Richmond (2)	QC	Wind	68.0	100.0%	68.0	Quebec PPA	2032
Total Eastern Canada			**1,479.0**		**1,331.5**		
Centralia	WA	Coal	1,340.0	100.0%	1,340.0	Merchant	n/a
Centralia Gas	WA	Gas	248.0	100.0%	248.0	Merchant	n/a
Power Resources	TX	Gas	212.0	50.0%	106.0	Merchant	n/a
Saranac	NY	Gas	240.0	37.5%	90.0	Merchant	n/a
Yuma	AZ	Gas	50.0	50.0%	25.0	LTC	2024
Imperial Valley	CA	Geothermal	327.0	50.0%	163.5	LTC	2016-2029
Skookumchuck	WA	Hydro	1.0	100.0%	1.0	LTC	2020
Wailuku	HI	Hydro	10.0	50.0%	5.0	LTC	2023
Total U.S.			**2,428.0**		**1,978.5**		
Parkeston	Australia	Gas	110.0	50.0%	55.0	LTC	2016
Southern Cross	Australia	Gas/Diesel	245.0	100.0%	245.0	LTC	2013
Total Australia			**355.0**		**300.0**		
Consolidated Total			**10,258.0**		**8,384.9**		

Note: (1) LTC - Long-term Contract.
(2) Project currently under construction.
Source: Company Reports, BMO Capital Markets

Table 58: *Consolidated Summary Sheet*

	Year Ending December 31									CAGR 2011A-2013E
	2005	2006	2007	2008	2009	2010	2011	2012E	2013E	
Total EPS (Diluted)	$0.88	$1.10	$1.26	$1.29	$0.85	$0.88	$1.04	$1.12	$1.15	5.3%
Total EPS (Basic)	$0.88	$1.10	$1.26	$1.29	$0.85	$0.88	$1.04	$1.12	$1.15	5.3%
First Call Consensus								*$1.11*	*$1.17*	
Dividends	$1.00	$1.00	$1.00	$1.06	$1.14	$1.16	$1.16	$1.16	$1.16	0.0%
Payout Ratio	113.9%	91.3%	79.7%	82.1%	134.1%	131.9%	112.0%	103.2%	101.0%	
Shares Outstanding (mm)	196.8	200.8	202.5	199.0	201.0	220.0	222.0	225.2	228.5	
Book Value	$12.87	$12.00	$11.44	$12.70	$13.41	$13.09	$12.11	$12.47	$12.86	
Market Valuation										
Price: High	$26.66	$26.91	$34.00	$37.50	$25.30	$23.98	$23.13	-	-	
Price: Low	$17.67	$20.22	$23.79	$21.00	$18.11	$19.61	$19.45	-	-	
Price: Current	-	-	-	-	-	-	-	$18.12	-	
P/E Ratio: High	30.4	24.6	27.1	29.0	29.8	27.3	22.3	-	-	
P/E Ratio: Low	20.1	18.5	18.9	16.3	21.3	22.3	18.8	-	-	
P/E Ratio: Current	-	-	-	-	-	-	-	16.1	15.8	
EV/EBITDA: High	10.3	9.5	10.6	11.2	11.9	11.2	9.7	-	-	
EV/EBITDA Value: Low	8.2	8.0	8.4	7.8	10.2	10.2	8.9	-	-	
Price/Book Value: Current	-	-	-	-	-	-	-	8.1	7.9	
Yield: High Price	3.8%	3.7%	2.9%	2.8%	4.5%	4.8%	5.0%	-	-	
Yield: Low Price	5.7%	4.9%	4.2%	5.0%	6.3%	5.9%	6.0%	-	-	
Yield: Current	-	-	-	-	-	-	-	6.4%	6.4%	
Balance Sheet ($mm)										
Debt (S-T)	409.5	611.6	804.6	687.0	1,094.0	900.0	1,120.0	792.6	446.4	
Debt (L-T)	1,887.0	1,681.5	1,496.2	1,889.0	2,794.0	2,785.0	2,542.0	2,542.0	2,542.0	
Debt (L-T) Non-Recourse	321.6	289.6	209.3	232.0	554.0	549.0	375.0	375.0	375.0	
Deferred Liabilities	1,114.4	1,123.0	1,216.1	1,117.0	1,133.0	1,167.0	1,221.0	1,117.0	1,117.0	
Minority Interest	558.6	535.0	496.4	469.0	478.0	435.0	358.0	469.0	469.0	
Preferred Securities	175.0	175.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Preferred Shares	0.0	0.0	0.0	0.0	0.0	300.0	562.0	562.0	562.0	
Shareholders' Equity	2,543.1	2,427.9	2,298.5	2,510.0	2,929.0	2,884.0	2,707.0	2,829.6	2,959.6	
	7,009.2	6,843.6	6,521.1	6,904.0	8,982.0	9,020.0	8,885.0	8,687.2	8,470.9	
Balance Sheet (%)										
Debt (S-T)	5.8%	8.9%	12.3%	10.0%	12.2%	10.0%	12.6%	9.1%	5.3%	
Debt (L-T)	26.9%	24.6%	22.9%	27.4%	31.1%	30.9%	28.6%	29.3%	30.0%	
Debt (L-T) Non-Recourse	4.6%	4.2%	3.2%	3.4%	6.2%	6.1%	4.2%	4.3%	4.4%	
Deferred Liabilities	15.9%	16.4%	18.6%	16.2%	12.6%	12.9%	13.7%	12.9%	13.2%	
Minority Interest	8.0%	7.8%	7.6%	6.8%	5.3%	4.8%	4.0%	5.4%	5.5%	
Preferred Securities	2.5%	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Preferred Shares	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%	6.3%	6.5%	6.6%	
Shareholders' Equity	36.3%	35.5%	35.2%	36.4%	32.6%	32.0%	30.5%	32.6%	34.9%	
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
Income Statement ($mm)										
Total Revenue	2,664.4	2,659.6	2,723.1	3,110.0	2,756.0	2,776.0	2,536.0	2,601.5	2,582.5	0.9%
EBITDA	834.0	915.2	936.3	961.0	839.0	913.0	1,044.0	1,082.9	1,076.4	1.5%
EBIT	441.2	514.5	534.0	533.0	364.0	440.0	544.0	565.5	551.1	0.6%
Net Earnings	173.8	221.2	255.1	256.9	170.9	193.5	230.0	253.2	262.5	6.8%
Operating Cash Flow	651.7	678.8	781.5	828.0	729.0	783.0	809.0	861.1	873.8	3.9%

Note: Priced as of market close on April 5, 2012.
Source: BMO Capital Markets, Company Reports

Appendix A – Key Industry Terms

Ancillary Services: Necessary services that must be provided in the generation and delivery of electricity, such as coordination and scheduling services including load following, energy imbalance service, control of transmission congestion; automatic generation control including load frequency control and the economic dispatch of plants; contractual agreements in terms of loss compensation service; and support of system integrity.

Availability: A measure of time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year, that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Avoided Cost: The cost that an electric utility would normally incur to produce or procure electricity but does not as the utility purchases it from qualifying facilities.

Baseload Generating Unit: An electric power facility that is normally operated continuously to meet an electric power system's minimum constant level of electric demand. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.

Boiler: A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

Bilateral Contract: A private commercial arrangement between a customer and a supplier. The terms including price, amount, source, delivery point and time of energy consumption are all subject to negotiation.

British Thermal Unit: A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

Capacity: A measure of the degree to which the capacity of a generating unit is being used during a certain time period. Usually calculated as the energy produced during a given time in kWh divided by the energy the facility could have produced if operating at its rated capacity.

Carbon Capture and Storage: An approach to mitigating the contribution of greenhouse gas emissions to global warming, which is based on capturing carbon dioxide emissions from industrial operations and permanently storing them in deep underground formations.

Cogeneration: The production of electricity and thermal energy (steam or heat) used for industrial, commercial, heating or cooling purposes.

Combined-Cycle Generation: The production of electricity through the simultaneous use of a combustion turbine and a steam turbine. Electricity is produced from otherwise 'lost heat' a natural byproduct from a combustion turbine which is run through a heat recovery steam turbine to produce electric power. The process increases the facility's efficiency.

Congestion: A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously.

Derate: To lower the rated electrical capability of a power generating facility or unit.

Demand-Side Management: Actions undertaken by a utility that results in a reduction in demand for electricity. This can eliminate or delay new capital investment for production or supply infrastructure and improve overall system efficiency.

Distributed Generation: Small-scale generation projects, typically 5 MW or under, implemented at or close to load centers thereby reducing transmission and distribution costs.

Federal Energy Regulatory Commission: A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric power licensing, natural gas pricing, oil pipeline rates and gas pipeline certification.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth.

Gigawatt: A measure of electric power equal to 1,000 megawatts.

Gigawatt hour (GWh): A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Greenhouse Gases: Gases such as carbon dioxide, methane and nitrous oxide that actively contribute to the atmospheric greenhouse effect. The greenhouse effect is the increasing mean global surface temperature of the earth caused by gases in the atmosphere. The effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Green Power: Electricity generation deemed to be environmentally less intrusive than most traditional generation, usually in accordance with standards established by government or regulatory agencies. Sources include wind, hydroelectric, landfill gas, and solar.

Hourly Ontario Energy Price (HOEP): The hourly price that is charged to Local Distributing Companies and other non-dispatchable loads. HOEP is also paid to self-scheduling generators. HOEP is defined as the hourly arithmetic average of the uniform Ontario energy price determined for each of the 12, 5-minute dispatch intervals in a particular hour.

Hourly Uplift Settlement Charges: Applied to all customers in the physical market. Ontario uses funds collected under these charges to pay for such items as the three types of Operating Reserve, any Congestion Management, Settlement Credits owed to dispatchable resources, Intertie Offer Guarantee payments, and other incurred hourly costs such as energy losses on the controlled grid.

Independent Power Producers (IPPs): Wholesale electricity producers that operate within the franchised service territory of host utilities and are usually authorized to sell at market-based rates. IPPs do not possess transmission facilities or sell electricity into the retail market.

Interruptible Power: Energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Kilowatt (kW): A measure of electric power equal to 1,000 watts.

Kilowatt hour (kWh): A measure of electricity consumtion equivalent to the use of 1,000 watts of power over a period of one hour.

Locational Marginal Cost Pricing: The variation in marginal pricing that may occur within a region due to the transmission distance.

Market Power: The ability of a generator to establish a price on its own without needing to compete with other suppliers.

Megawatt (MW): A measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh): A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Net Maximum Capacity: The maximum capacity or effective rating, modified for ambient limitations, that power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

On Peak Average Price: The price of electricity calculated during the period during which maximum daily load usually occurs.

Off Peak Average Price: The price of electricity calculated during periods of the day when heavy load does not typically occur (i.e. throughout the night, and on weekends and holidays).

Open Access: Non-discriminatory access to electricity transmission lines.

Peaking Unit: An electric power facility designed to generate electricity on short notice and for relatively brief time periods.

Power Purchase Arrangement (Alberta): A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA Buyers.

Qualifying Facility (QF): A class of power generators created under the Public Utility Regulatory Policies Act (PURPA) of 1978 that meet certain guidelines, which include generating less than 80 MW of power at any given time and using alternative energy sources such as biomass, wood waste or other renewables. Electric utilities are obligated to purchase power from QFs at a price approved by state regulators.

Reserve Margin: The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability.

Stranded Assets: A utility asset that is no longer economically viable because its cost of production is higher than a competitor's within its transmission range.

Stranded Costs: Costs that cannot be recovered from market prices.

Supercritical Technology: The most advanced coal-combustion technology in Canada employing a supercritical boiler, high-efficiency multi-stage turbine, flue gas desulphurization unit (scrubber), bag house, and low nitrogen oxide burners.

Transmission Losses: Energy lost during transportation from suppliers to end-users. Energy losses on a typical large electric system is 5-8%.

Unbundling: Separation of the vertically integrated functions of utility companies into generation, transmission, distribution and energy services.

Uprate: To increase the rated electrical capability of a power generating facility.

Wheeling: The transmission of power belonging to one utility through another utility's transmission grid.

IMPORTANT DISCLOSURES

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I, Ben Pham, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

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Atlantic Power (ATP-TSX; AT-NYSE)	1, 2, 3, 4, 5, 6AC, 8	Emera (EMA-TSX)	1, 2, 3, 4, 5, 6AC, 8, 18
Boralex (BLX-TSX)	2, 4, 6A	Fortis (FTS-TSX)	1, 2, 3, 4, 5, 6AC, 8
Canadian Utilities (CU-TSX)	1, 2, 3, 4, 6A, 8, 18	Innergex Renewable Energy (INE-TSX)	2, 4, 5, 6AC, 8
Capital Power (CPX-TSX)	1, 2, 3, 4, 6A, 8, 18	Northland Power (NPI-TSX)	1, 2, 3, 4, 5, 6AC, 8
Capstone Infrastructure (CSE-TSX)	1, 2, 3, 4, 6A, 8	TransAlta (TA-TSX; TAC-NYSE)	1, 2, 3, 4, 5, 6AC, 8, 13, 15, 18

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Rating Category	BMO Rating	BMOCM US Universe*	BMOCM US IB Clients**	BMOCM US IB Clients***	BMOCM Universe****	BMOCM IB Clients*****	Starmine Universe
Buy	Outperform	38.0%	10.3%	40.4%	40.7%	46.2%	56.2%
Hold	Market Perform	60.3%	9.6%	59.6%	56.3%	52.2%	39.4%
Sell	Underperform	1.7%	0.0%	0.0%	3.0%	1.6%	4.4%

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R38964

ADDITIONAL INFORMATION IS AVAILABLE UPON REQUEST

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A member of **BMO Financial Group**

Attachment 28.1

(Provided in electronic format only due to
document size and in order to conserve paper)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

/X/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2011

OR

/ / TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________ to ___________

Commission File Number	Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices, zip code telephone number	I.R.S. Employer Identification Number
1-16305	**PUGET ENERGY, INC.** A Washington Corporation 10885 NE 4th Street, Suite 1200 Bellevue, Washington 98004-5591 (425) 454-6363	91-1969407
1-4393	**PUGET SOUND ENERGY, INC.** A Washington Corporation 10885 NE 4th Street, Suite 1200 Bellevue, Washington 98004-5591 (425) 454-6363	91-0374630

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Puget Energy, Inc.	Yes	/ /	No	/X/	Puget Sound Energy, Inc.	Yes	/X/	No / /

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Puget Energy, Inc.	Yes	/ /	No	/X/	Puget Sound Energy, Inc.	Yes	/ /	No /X/

Indicate by check mark whether the registrants: (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Puget Energy, Inc.	Yes	/X/	No	/ /	Puget Sound Energy, Inc.	Yes	/X/	No / /

Indicate by check mark whether the registrants have submitted electronically and posted on its corporate websites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to post such files).

Puget Energy, Inc.	Yes	/X/	No	/ /	Puget Sound Energy, Inc.	Yes	/X/	No / /

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. /X/

Indicate by check mark whether registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Puget Energy, Inc.	Large accelerated filer	/ /	Accelerated filer	/ /	Non-accelerated filer	/X/	Smaller reporting company	/ /
Puget Sound Energy, Inc.	Large accelerated filer	/ /	Accelerated filer	/ /	Non-accelerated filer	/X/	Smaller reporting company	/ /

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Puget Energy, Inc.	Yes	/ /	No	/X/	Puget Sound Energy, Inc.	Yes	/ /	No /X/

As of February 6, 2009, all of the outstanding shares of voting stock of Puget Energy, Inc. are held by Puget Equico LLC, an indirect wholly-owned subsidiary of Puget Holdings LLC.

All of the outstanding shares of voting stock of Puget Sound Energy, Inc. are held by Puget Energy, Inc.

This Report on Form 10-K is a combined report being filed separately by: Puget Energy, Inc. and Puget Sound Energy, Inc. Puget Sound Energy, Inc. makes no representation as to the information contained in this report relating to Puget Energy, Inc. and the subsidiaries of Puget Energy, Inc. other than Puget Sound Energy, Inc. and its subsidiaries.

INDEX

DEFINITIONS

AFUDC	Allowance for Funds Used During Construction
aMW	Average Megawatt
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BPA	Bonneville Power Administration
Colstrip	Colstrip, Montana coal-fired steam electric generation facility
Dth	Dekatherm (one Dth is equal to one MMBtu)
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gases
Goldendale	Goldendale electric generating facility
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
kWh	Kilowatt Hour (one kWh equals one thousand watt hours)
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
LTI Plan	Long-Term Incentive Plan
Mint Farm	Mint Farm Electric Generating Station
MMBtu	One Million British Thermal Units
MW	Megawatt (one MW equals one thousand kW)
MWh	Megawatt Hour (one MWh equals one thousand kWh)
NERC	North American Electric Reliability Corporation
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NOAA	National Oceanic and Atmospheric Administration
NPNS	Normal Purchase Normal Sale
NWP	Northwest Pipeline GP
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
PCA	Power Cost Adjustment
PCORC	Power Cost Only Rate Case
PGA	Purchased Gas Adjustment
PSE	Puget Sound Energy, Inc.
PTC	Production Tax Credit

PUDs	Washington Public Utility Districts
Puget Energy	Puget Energy, Inc.
Puget Equico	Puget Equico LLC
Puget Holdings	Puget Holdings LLC
PURPA	Public Utility Regulatory Policies Act
REC	Renewable Energy Credit
REP	Residential Exchange Program
SEC	United States Securities and Exchange Commission
Tenaska	Tenaska Power Fund, L.P.
VIE	Variable Interest Entity
Washington Commission	Washington Utilities and Transportation Commission
Wild Horse	Wild Horse wind project

FORWARD-LOOKING STATEMENTS

Puget Energy, Inc. (Puget Energy) and Puget Sound Energy, Inc. (PSE) include the following cautionary statements in this Form 10-K to make applicable and to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by or on behalf of Puget Energy or PSE. This report includes forward-looking statements, which are statements of expectations, beliefs, plans, objectives and assumptions of future events or performance. Words or phrases such as “anticipates,” “believes,” “continues,” “could,” “estimates,” “expects,” “future,” “intends,” “may,” “might,” “plans,” “potential,” “predicts,” “projects,” “should,” “will likely result,” “will continue” or similar expressions are intended to identify certain of these forward-looking statements.

Forward-looking statements reflect current expectations and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. Puget Energy’s and PSE’s expectations, beliefs and projections are expressed in good faith and are believed by Puget Energy and PSE, as applicable, to have a reasonable basis, including without limitation, management’s examination of historical operating trends, data contained in records and other data available from third parties. However, there can be no assurance that Puget Energy’s and PSE’s expectations, beliefs or projections will be achieved or accomplished. Puget Energy and PSE are collectively referred to herein as “the Company.”

In addition to other factors and matters discussed elsewhere in this report, some important factors that could cause actual results or outcomes for Puget Energy and PSE to differ materially from those discussed in forward-looking statements include:

- Governmental policies and regulatory actions, including those of the Federal Energy Regulatory Commission (FERC) and the Washington Utilities and Transportation Commission (Washington Commission), with respect to allowed rates of return, cost recovery, financing, industry and rate structures, transmission and generation business structures within PSE, acquisition and disposal of assets and facilities, operation, maintenance and construction of electric generating facilities, natural gas and electric distribution and transmission facilities, licensing of hydroelectric operations and natural gas storage facilities, recovery of other capital investments, recovery of power and natural gas costs, recovery of regulatory assets, implementation of energy efficiency programs and present or prospective wholesale and retail competition;
- Failure of PSE to comply with the FERC or the Washington Commission standards and/or rules, which could result in penalties based on the discretion of either commission;
- Findings of noncompliance with electric reliability standards developed by the North American Electric Reliability Corporation (NERC) or the Western Electricity Coordinating Council for users, owners and operators of the power system, which could result in penalties;
- Changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning the environment, climate change, greenhouse gas or other emissions or byproducts of electric generation (including coal ash or other substances), natural resources, and fish and wildlife (including the Endangered Species Act) as well as the risk of litigation arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures;
- The ability to recover costs arising from changes in enacted federal, state or local tax laws in a timely manner;
- Changes in tax law, related regulations or differing interpretation or enforcement of applicable law by the Internal Revenue Service (IRS) or other taxing jurisdiction;
- Inability to realize deferred tax assets and use production tax credits (PTCs) due to insufficient future taxable income;
- Accidents or natural disasters, such as hurricanes, windstorms, earthquakes, floods, fires and landslides, which can interrupt service and lead to lost revenue, cause temporary supply disruptions and/or price spikes in the cost of fuel and raw materials and impose extraordinary costs;
- Commodity price risks associated with procuring natural gas and power in wholesale markets or counterparties extending credit to PSE without collateral posting requirements;
- Wholesale market disruption, which may result in a deterioration of market liquidity, increase the risk of counterparty default, affect the regulatory and legislative process in unpredictable ways, negatively affect wholesale energy prices and/or impede PSE’s ability to manage its energy portfolio risks and procure energy supply, affect the availability and access to capital and credit markets and/or impact delivery of energy to PSE from its suppliers;
- Financial difficulties of other energy companies and related events, which may affect the regulatory and legislative process in unpredictable ways, adversely affect the availability of and access to capital and credit markets and/or impact delivery of energy to PSE from its suppliers;
- The effect of wholesale market structures (including, but not limited to, regional market designs or transmission organizations) or other related federal initiatives;
- PSE electric or natural gas distribution system failure, which may impact PSE’s ability to deliver energy supply to its customers;

- Changes in climate or weather conditions in the Pacific Northwest, which could have effects on customer usage and PSE’s revenue and expenses;
- Regional or national weather, which can have a potentially serious impact on PSE’s ability to procure adequate supplies of natural gas, fuel or purchased power to serve its customers and on the cost of procuring such supplies;
- Variable hydrological conditions, which can impact streamflow and PSE’s ability to generate electricity from hydroelectric facilities;
- Electric plant generation and transmission system outages, which can have an adverse impact on PSE’s expenses with respect to repair costs, added costs to replace energy or higher costs associated with dispatching a more expensive generation resource;
- The ability of a natural gas or electric plant to operate as intended;
- The ability to renew contracts for electric and natural gas supply and the price of renewal;
- Blackouts or large curtailments of transmission systems, whether PSE’s or others’, which can affect PSE’s ability to deliver power or natural gas to its customers and generating facilities;
- The ability to restart generation following a regional transmission disruption;
- The failure of the interstate natural gas pipeline delivering to PSE’s system, which may impact PSE’s ability to adequately deliver natural gas supply or electric power to its customers;
- Industrial, commercial and residential growth and demographic patterns in the service territories of PSE;
- General economic conditions in the Pacific Northwest, which may impact customer consumption or affect PSE’s accounts receivable;
- The loss of significant customers, changes in the business of significant customers or the condemnation of PSE’s facilities, which may result in changes in demand for PSE’s services;
- The failure of information systems or the failure to secure information system data, which may impact the operations and cost of PSE’s customer service, generation, distribution and transmission;
- The impact of acts of God, terrorism, flu pandemic or similar significant events;
- Capital market conditions, including changes in the availability of capital and interest rate fluctuations;
- Employee workforce factors, including strikes, work stoppages, availability of qualified employees or the loss of a key executive;
- The ability to obtain insurance coverage and the cost of such insurance;
- The ability to maintain effective internal controls over financial reporting and operational processes;
- Changes in Puget Energy’s or PSE’s credit ratings, which may have an adverse impact on the availability and cost of capital for Puget Energy or PSE generally, or the failure to comply with the covenants in Puget Energy’s or PSE’s credit facilities, which would limit the Companies’ ability to utilize such facilities for capital; and
- Deteriorating values of the equity, fixed income and other markets which could significantly impact the value of investments of PSE’s retirement plan, post-retirement medical benefit plan trusts and the funding of obligations thereunder.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, Puget Energy and PSE undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. You are also advised to consult the reports on Form 10-Q and current reports on Form 8-K, as well as Item 1A - “Risk Factors” on this Form 10-K.

PART I

ITEM 1. BUSINESS

GENERAL

Puget Energy is an energy services holding company incorporated in the state of Washington in 1999. All of its operations are conducted through its subsidiary, PSE, a utility company. Puget Energy has no significant assets other than the stock of PSE.

On February 6, 2009, Puget Holdings LLC (Puget Holdings) completed its merger with Puget Energy. Puget Holdings is a consortium of long-term infrastructure investors including Macquarie Infrastructure Partners I, Macquarie Infrastructure Partners II, Macquarie Capital Group Limited, Macquarie-FSS Infrastructure Trust, the Canada Pension Plan Investment Board (CPPIB), the British Columbia Investment Management Corporation and the Alberta Investment Management Corporation. As a result of the merger, all of Puget Energy's common stock is indirectly owned by Puget Holdings.

CORPORATE STRATEGY

Puget Energy is the direct parent company of PSE, the oldest and largest electric and natural gas utility headquartered in the state of Washington, primarily engaged in the business of electric transmission, distribution, generation and natural gas distribution. Puget Energy's business strategy is to generate stable earnings and cash flow by offering reliable electric and natural gas service in a cost-effective manner through PSE.

PUGET SOUND ENERGY, INC.

PSE is a public utility incorporated in the state of Washington in 1960. PSE furnishes electric and natural gas service in a territory covering approximately 6,000 square miles, principally in the Puget Sound region.

The following table presents the number of PSE customers as of December 31, 2011 and 2010:

	Electric			Gas		
	December 31		Percent	December 31		Percent
	2011	2010	Change	2011	2010	Change
Customers: [1]						
Residential	959,547	954,898	0.5%	704,134	696,988	1.0%
Commercial	119,610	118,706	0.8	54,106	53,981	0.2
Industrial	3,622	3,637	(0.4)	2,475	2,498	(0.9)
Other	3,503	3,451	1.5	180	169	6.5
Total	1,086,282	1,080,692	0.5%	760,895	753,636	1.0%

1 *At December 31, 2011 approximately 379,874 customers purchased both electricity and natural gas from PSE.*

During 2011, PSE's billed retail and transportation revenue from electric utility operations were derived 53.5% from residential customers, 40.0% from commercial customers, 5.1% from industrial customers and 1.4% from other customers. PSE's retail revenue from natural gas utility operations were derived 65.9% from residential customers, 29.8% from commercial customers, 3.0% from industrial customers and 1.3% from transportation customers in 2011. During this period, the largest customer accounted for approximately 1.6% of PSE's operating revenue.

PSE is affected by various seasonal weather patterns and therefore, utility revenue and associated expenses are not generated evenly during the year. Energy usage varies seasonally and monthly, primarily as a result of weather conditions. PSE experiences its highest retail energy sales in the first and fourth quarters of the year. Sales of electricity to wholesale customers also vary by quarter and year depending principally upon fundamental market factors and weather conditions. PSE has a Purchased Gas Adjustment (PGA) mechanism in retail natural gas rates to recover variations in natural gas supply and transportation costs. PSE also has a Power Cost Adjustment (PCA) mechanism in retail electric rates to recover variations in electricity costs on a shared basis with customers.

In the five-year period ended December 31, 2011, PSE's gross electric utility plant additions were $3.6 billion and retirements were $383.3 million. In the same five-year period, PSE's gross natural gas utility plant additions were $839.0

million and retirements were $125.0 million and PSE's gross common utility plant additions were $342.7 million and retirements were $290.3 million. Gross electric utility plant at December 31, 2011 was approximately $8.4 billion, which consisted of 43.0% distribution, 31.1% generation, 6.2% transmission and 19.7% general plant and other. Gross natural gas utility plant at December 31, 2011 was approximately $2.9 billion, which consisted of 93.7% distribution and 6.3% general plant and other. Gross common utility general and intangible plant at December 31, 2011 was approximately $518.3 million.

EMPLOYEES

At December 31, 2011, Puget Energy had no employees and PSE had approximately 2,800 full-time employees. Approximately 1,240 PSE employees are represented by the United Association of Plumbers and Pipefitters (UA) and the International Brotherhood of Electrical Workers Union (IBEW). The current contracts with the UA and the IBEW expire September 30, 2013 and March 31, 2014, respectively.

CORPORATE LOCATION

Puget Energy's and PSE's principal executive offices are located at 10885 NE 4th Street, Suite 1200, Bellevue, Washington 98004 and the telephone number is (425) 454-6363.

AVAILABLE INFORMATION

The information required by Item 101(e) of Regulation S-K is incorporated herein by reference to the material under "Additional Information" in Item 10 Part III of this annual report.

REGULATION AND RATES

PSE is subject to the regulatory authority of: (1) the FERC with respect to the transmission of electricity, the sale of electricity at wholesale, accounting and certain other matters; and (2) the Washington Commission as to retail rates, accounting, the issuance of securities and certain other matters. PSE also must comply with mandatory electric system reliability standards developed by the NERC, the electric reliability organization certified by the FERC, which standards are enforced by the Western Electricity Coordinating Council in PSE's operating territory.

FERC TRANSMISSION RATE FILING

On January 6, 2012, PSE filed an electric transmission rate case with FERC as well as an increase in ancillary service charges. PSE is requesting a rate increase of $3.8 million with an effective date of April 1, 2012. In the filing, PSE requested a formula transmission rate for network and point-to-point transmission service. A formula rate is a fixed methodology for calculating a rate based upon various cost and billing determinant inputs to recover the operating costs of the transmission system. The formula rate is updated annually and posted on PSE's Open Access Same-Time Information System (OASIS) with an informational filing to FERC. This streamlined process allows PSE to recover its costs on a timely basis, provides for a transparent process with transmission customers and seeks to ensure that there is no under or over collection. Formula transmission rates are encouraged and broadly accepted by FERC.

ELECTRIC REGULATION AND RATES

Electric Rate Case. On June 13, 2011, PSE filed a general rate increase with the Washington Commission which proposed an increase in electric rates of $160.7 million or 8.1%, to be effective May 2012. PSE requested a weighted cost of capital of 8.42%, or 7.29% after-tax, and a capital structure of 48.0% in common equity with a return on equity of 10.8%. The filing also proposes a conservation savings adjustment mechanism related to energy efficiency services for business and residential customers. On September 1, 2011, PSE filed supplemental testimony to adjust the electric rate increase to $152.3 million, a 7.7% increase to rates, due to changes in projected power costs. On January 17, 2012, PSE filed rebuttal testimony which included a reduction to the requested electric rate increase to $126.0 million. The $26.3 million reduction was primarily due to updates to power costs and to a change to the weighted cost of capital to 8.26%, or 7.17% after-tax, which included a change to the return on equity to 10.75%. Hearings related to this matter were held on February 14 through 17, 2012.

The Washington Commission issued an order in 2010 relating to how Renewable Energy Credit (REC) proceeds should be handled for regulatory accounting and ratemaking purposes. The order required REC proceeds to be recorded as regulatory liabilities and that amounts recorded would accrue interest. In its petition, PSE had sought approval for $21.1

million of REC proceeds to be used as an offset against its California wholesale energy sales regulatory asset. In response to the order, PSE adjusted the carrying value of its regulatory asset in the second quarter of 2010 by $17.8 million (from $21.1 million to $3.3 million), with the $3.3 million then offset against the Company's RECs regulatory liability. The Company's California wholesale energy sales regulatory asset represented unpaid bills for power sold into the markets maintained by the California Independent System Operator during the 2000-2001 California Energy Crisis, the claims of which were settled along with all counterclaims against PSE in a settlement agreement approved by the FERC on July 1, 2009.

On May 20, 2010, PSE filed an accounting petition requesting that the Washington Commission approve: (1) the creation of a regulatory asset account for the prepayments made to the Bonneville Power Administration (BPA) associated with network upgrades to the Central Ferry substation related to the Lower Snake River wind project; (2) the monthly accrual of carrying charges on that regulatory asset at PSE's approved net of tax rate of return; and (3) the ability to provide customers the BPA interest received through a reduction to transmission expense. The petition is still pending approval by the Washington Commission.

Effective July 1, 2010, the Washington Commission approved a change in PSE's PTC tariff as PSE has not been able to utilize PTCs since 2007, due to insufficient taxable income caused primarily by bonus tax depreciation. The Washington Commission approved PSE suspending its PTC tariff, effective July 1, 2010. This resulted in an overall increase in PSE's electric rates of 1.7%, with no impact to net income.

On September 22, 2010, a joint proposal and accounting petition was filed with the Washington Commission by PSE, Washington Commission Staff and Industrial Customers of Northwest Utilities which addressed how to recover PTCs provided to customers that have not been utilized and addresses REC proceeds to be returned to customers. On October 26, 2010, the Washington Commission issued an order granting the joint proposal and accounting petition. The order allows the Company to credit customers for REC revenue received and deferred through November 2009. This credit reduced rates by $27.7 million, or 2.9%, over five months beginning November 2010 through March 2011. RECs received after November 2009 will be retained by PSE and will be used to recapture the benefit of PTCs previously provided to customers. Once these PTCs are utilized by PSE on its tax return, the customers will receive the benefit. There is no impact to net income related to these items.

On December 30, 2010, the Washington Commission approved revisions to PSE's PTC tariff, effective January 1, 2011, which changed the methodology by which PTCs are passed-through to customers. Due to the uncertainty of realizing the benefit of PTCs, the PTCs will pass-through to customers following the year in which they are able to be utilized on PSE's tax return, rather than in the same year in which they are generated by qualifying wind powered facilities. The rate schedule will pass-through $5.5 million of the $28.7 million treasury grant in 2011. The Washington Commission order authorized PSE to pass back one-tenth of the treasury grant on an annual basis and includes 23 months of treasury grant amortization to customers from February 2010 through December 2011, which represents the month the treasury grant funds were received through the end of the period over which the rates will be set. This represents an overall average rate reduction of 0.3%, with no impact to net income. Since the tariff now addresses additional federal incentives, it has been renamed the Federal Incentive Tracker.

The following table sets forth electric rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Type of Rate Adjustment	Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
Renewable Energy Credit Proceeds	November 1, 2010 – March 31, 2011	(2.9)%	$ (27.7)
Electric General Rate Case	April 8, 2010, Annual	3.7	74.1

Natural Gas Regulation and Rates

Natural Gas Rate Case. On June 13, 2011, PSE filed a general rate increase with the Washington Commission which proposed an increase in natural gas rates of $31.9 million or 3.0%, to be effective May 2012. PSE requested a weighted cost of capital of 8.42%, or 7.29% after-tax, and a capital structure of 48.0% in common equity with a return on equity of 10.8%. The filing also proposes a conservation savings adjustment mechanism related to energy efficiency services for business and residential customers. On January 17, 2012, PSE filed rebuttal testimony which included a reduction to the requested natural gas rate increase to $28.6 million. The $3.3 million reduction was primarily due to a change to the weighted cost of capital to 8.26%, or 7.17% after-tax, which included a change to the return on equity to 10.75%. Hearings related to this matter were held on February 14 through 17, 2012.

On March 14, 2011, the Washington Commission issued its order authorizing PSE to increase its natural gas general tariff rates by $19.0 million or 1.8% on an annual basis effective April 1, 2011.

On April 26, 2011, PSE filed a new tariff for a Natural Gas Pipeline Integrity Program. This program is intended to enhance pipeline safety by providing for the timely recovery of the Company's cost to replace certain natural gas system infrastructure that would emphasize system reliability, integrity and safety which would increase natural gas revenue by $1.9 million or 0.2%. The Washington Commission held a hearing on November 17, 2011 and an order from the Washington Commission is pending.

On October 27, 2011, the Washington Commission approved PSE's PGA natural gas tariff filing effective November 1, 2011, to decrease the rates charged to customers under the PGA. The estimated revenue impact of the approved charge is a decrease of $43.5 million, or 4.3% annually. The rate adjustment has no impact on PSE's net income.

PSE has a PGA mechanism in retail natural gas rates to recover variations in natural gas supply and transportation costs. Variations in natural gas rates are passed through to customers; therefore, PSE's net income is not affected by such variations. Changes in the PGA rates affect PSE's revenue, but do not impact net income as the changes to revenue are offset by increased or decreased purchased gas and gas transportation costs.

The following table sets forth natural gas rate adjustments approved by the Washington Commission and the corresponding impact on PSE's annual revenue based on the effective dates:

Type of Rate Adjustment	Effective Date	Average Percentage Increase (Decrease) in Rates	Annual Increase (Decrease) in Revenue (Dollars in Millions)
Purchased Gas Adjustment	November 1, 2011	(4.3)%	$ (43.5)
Natural Gas General Tariff Adjustment	April 1, 2011	1.8	19.0
Purchased Gas Adjustment	November 1, 2010 – October 31, 2011	1.9	18.3
Natural Gas General Rate Case	April 8, 2010	0.8	10.1
Purchased Gas Adjustment	October 1, 2009 – October 31, 2010	(17.1)	(198.1)
Purchased Gas Adjustment	June 1, 2009 – May 31, 2010	(1.8)	(21.2)
Purchased Gas Adjustment	October 1, 2008 – September 30, 2009	11.1	108.8

ELECTRIC UTILITY OPERATING STATISTICS

	YEAR ENDED DECEMBER 31,		
	2011	2010	2009
Generation and purchased power, MWh			
Company-controlled resources	7,881,574	11,220,935	10,748,523
Contracted resources	8,503,356	8,188,156	8,285,761
Non-firm energy purchased	8,586,066	5,683,635	6,935,600
Total generation and purchased power	24,970,996	25,092,726	25,969,884
Less: losses and Company use	(1,655,797)	(1,685,890)	(1,568,372)
Total energy sales, MWh	23,315,199	23,406,836	24,401,512
Electric energy sales, MWh			
Residential	11,045,115	10,672,887	11,163,371
Commercial	9,181,261	9,100,518	9,488,763
Industrial	1,214,232	1,160,588	1,148,060
Other customers	101,617	99,679	103,537
Total energy billed to customers	21,542,225	21,033,672	21,903,731
Unbilled energy sales – net (decrease) increase	(38,355)	(125,288)	(29,652)
Total energy sales to customers	21,503,870	20,908,384	21,874,079
Sales to other utilities and marketers	1,811,328	2,498,452	2,527,433
Total energy sales, MWh	23,315,198	23,406,836	24,401,512
Transportation, including unbilled	2,008,542	1,954,913	2,030,110
Electric energy sales and transportation, MWh	25,323,740	25,361,749	26,431,622
Electric operating revenue by classes (dollars in thousands):			
Residential	$ 1,144,165	$ 1,078,262	$ 1,067,274
Commercial	853,880	836,957	838,275
Industrial	108,247	103,678	99,552
Other customers	19,122	18,694	18,392
Operating revenue billed to customers	2,125,414	2,037,591	2,023,493
Unbilled revenue – net (decrease) increase	(1,471)	(5,907)	(1,968)
Total operating revenue from customers	2,123,943	2,031,684	2,021,525
Transportation, including unbilled	10,275	11,000	10,623
Sales to other utilities and marketers	45,725	62,943	78,471
Miscellaneous operating revenue	(32,723)	1,842	(11,883)
Total electric operating revenue	$ 2,147,220	$ 2,107,469	$ 2,098,736
Number of customers served (average):			
Residential	957,205	952,803	947,299
Commercial	119,266	118,595	118,423
Industrial	3,633	3,660	3,695
Other	3,462	3,426	3,403
Transportation	17	17	17
Total customers	1,083,583	1,078,501	1,072,837

	YEAR ENDED DECEMBER 31,		
	2011	2010	2009
Average kWh used per customer:			
Residential	11,539	11,202	11,784
Commercial	76,981	76,736	80,126
Industrial	334,223	317,100	310,706
Other	29,352	29,095	30,425
Average revenue billed per customer:			
Residential	$ 1,195	$ 1,132	$ 1,127
Commercial	7,159	7,057	7,079
Industrial	29,795	28,327	26,942
Other	5,523	5,457	5,405
Average retail revenue per kWh sold:			
Residential	$ 0.1036	$ 0.1010	$ 0.0956
Commercial	0.0930	0.0920	0.0883
Industrial	0.0891	0.0893	0.0867
Other	0.1882	0.1875	0.1776
Average retail revenue per kWh sold	0.0982	0.0969	0.0924
Heating degree days	5,146	4,549	4,897
Percent of normal – NOAA[1] 30-year average	107.3%	94.8%	102.1%
Load factor [2]	61.2%	56.7%	54.5%

1 *National Oceanic and Atmospheric Administration (NOAA).*

2 *Average usage by customers divided by their maximum usage.*

ELECTRIC SUPPLY

At December 31, 2011, PSE's electric power resources, which include company-owned or controlled resources as well as those under long-term contract, had a total capacity of approximately 4,707 megawatts (MW). PSE's historical peak load of approximately 4,912 MW occurred on December 10, 2009. In order to meet an extreme winter peak load, PSE may supplement its electric power resources with winter-peaking call options and other instruments that may include, but are not limited to, weather-related hedges. When it is more economical for PSE to purchase power than to operate its own generation facilities, PSE will purchase spot market energy.

The following table shows PSE's electric energy supply resources and energy production for the years ended December 31, 2011 and 2010:

	Peak Power Resources At December 31				Energy Production At December 31			
	2011		2010		2011		2010	
	MW	%	MW	%	MWh	%	MWh	%
Purchased resources:								
Columbia River PUD contracts [1]	843	17.8%	1,027	19.4%	5,610,424	24.2%	4,330,176	19.2%
Other hydroelectric [2]	145	3.1	145	2.7	655,371	2.8	635,996	2.8
Other producers [2]	752	16.0	1,170	22.0	2,104,612	9.1	3,101,364	13.7
Wind	50	1.1	50	0.9	132,950	0.6	120,632	0.5
Short-term wholesale energy purchases [3]	N/A	N/A	N/A	N/A	6,774,737	29.3	3,185,183	14.1
Total purchased	1,790	38.0%	2,392	45.0%	15,278,094	66.0%	11,373,351	50.3%
Company-controlled resources:								
Hydroelectric	192	4.1%	192	3.6%	683,977	3.0%	929,595	4.1%
Coal	677	14.4	677	12.7	4,210,583	18.1	5,198,105	23.0
Natural gas/oil	1,618	34.4	1,627	30.6	1,823,138	7.9	4,102,298	18.2
Wind	430	9.1	430	8.1	1,163,876	5.0	990,925	4.4
Total company-controlled	2,917	62.0%	2,926	55.0%	7,881,574	34.0%	11,220,923	49.7%
Total	4,707	100.0%	5,318	100.0%	23,159,668	100.0%	22,594,274	100.0%

1 *Net of 59 MW of capacity delivered to Canada pursuant to the provisions of a treaty between Canada and the United States and Canadian Entitlement Allocation agreements.*

2 *Power received from other utilities and firm contracts are classified between hydroelectric and other producers based on the character of the utility system used to supply the power or, if the power is supplied from a particular resource, the character of that resource.*

3 *Short-term wholesale purchases, net of resale, of 1,811,328 megawatt hours (MWh) and 2,498,452 MWh account for 29.3% and 14.1% of energy production, for 2011 and 2010, respectively.*

COMPANY – OWNED ELECTRIC GENERATION RESOURCES

At December 31, 2011, PSE owns or controls the following plants with an aggregate net generating capacity of 2,917 MW:

PLANT NAME	PLANT TYPE	NET MAXIMUM CAPACITY (MW) [1]	YEAR INSTALLED
Colstrip Units 3 & 4 (25% interest)	Coal	370	1984 & 1986
Colstrip Units 1 & 2 (50% interest)	Coal	307	1975 & 1976
Mint Farm	Natural gas combined cycle	297	2007
Goldendale	Natural gas combined cycle	278	2004
Frederickson Unit 1 (49.85% interest)	Natural gas combined cycle	136	2002; added duct firing in 2005
Wild Horse	Wind	273	2006; added 22 turbines in 2009
Hopkins Ridge	Wind	157	2005; added 4 turbines in 2008
Fredonia Units 1 & 2	Dual-fuel combustion turbines	207	1984
Frederickson Units 1 & 2	Dual-fuel combustion turbines	149	1981
Whitehorn Units 2 & 3	Dual-fuel combustion turbines	149	1981
Fredonia Units 3 & 4	Dual-fuel combustion turbines	107	2001
Encogen	Natural gas cogeneration	165	1993
Sumas	Natural gas cogeneration	127	1993
Upper Baker River [2]	Hydroelectric	91	1959
Lower Baker River [2]	Hydroelectric	79	1925; reconstructed 1960; upgraded 2001
Snoqualmie Falls [3]	Hydroelectric	--	1898 to 1911 & 1957; currently no output due to rebuild
Electron [4]	Hydroelectric	22	1904 to 1929
Crystal Mountain	Internal combustion	3	1969
Total net capacity		2,917	

1 *Net Maximum Capacity is the capacity a unit can sustain over a specified period of time when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads.*

2 *The FERC jurisdictional facility, operated pursuant to 50-year license granted by the FERC in October 2008, will require net present value funds between $305.0 million to $325.0 million for capital expenditures and operations and maintenance costs over 50 years in order to implement the license conditions. The license provides protection and enhancements for fish and wildlife, water quality, recreation and cultural and historic resources.*

3 *The FERC jurisdictional facility, operated pursuant to 40-year license granted by the FERC in June 2004, will require net present value funds between $240.0 million to $260.0 million for capital expenditures and operations and maintenance costs over 40 years in order to implement the license conditions. Snoqualmie Falls will have partial output upon completion of powerhouse 2 anticipated for March 2013. The plant is expected to be fully operational and provide a net maximum capacity of approximately 54 MW upon completion of powerhouse 1 expected in the second quarter of 2013.*

4 *At December 31, 2011, Electron project output is limited to approximately 7 MW due to the condition of the flume that conveys water to the plant. This limitation is expected through at least late 2013.*

COLUMBIA RIVER ELECTRIC ENERGY SUPPLY CONTRACTS

During 2011, approximately 24.2% of PSE's energy requirement was obtained through long-term contracts with three Washington Public Utility Districts (PUDs) that own and operate hydroelectric projects on the Columbia River. PSE agrees to pay a share of the annual debt service, operating and maintenance costs and other expenses associated with each project in proportion to its share of projected output. PSE's payments are not contingent upon the projects being operable.

As of December 31, 2011, PSE was entitled to purchase portions of the power output of the PUDs' projects as set forth below:

			Company's Annual Purchasable Amount (Approximate)	
Project	Contract Expiration Year	License Expiration Year	Percent of Output	Megawatt Capacity
Chelan County PUD: [1]				
Rock Island Project	2012	2029	50.0%	312
Rocky Reach Project	2031	2052	25.0%	325
Douglas County PUD: [2]				
Wells Project	2018	2012	29.9%	251
Grant County PUD: [3]				
Priest Rapids Development	2052	2052	0.8%	7
Wanapum Development	2052	2052	0.8%	7
Total				902

1 *On February 3, 2006, PSE and Chelan entered into a new Power Sales Agreement and a related Transmission Agreement for 25.0% of the output of Chelan's Rocky Reach and Rock Island hydroelectric generating facilities, located on the mid-Columbia River, in exchange for PSE paying 25.0% of the operating costs of the facilities. The agreements terminate in 2031 and provide that PSE will begin to receive power upon expiration of PSE's existing long-term contracts with Chelan for the Rocky Reach and Rock Island output (expiring in 2011 and 2012, respectively). PSE made a non-refundable capacity reservation payment of $89.0 million as required by the agreements. The Washington Commission determined the prudence of PSE entering into the new Chelan contracts and confirmed the treatment of the $89.0 million as a regulatory asset as part of its order in PSE's general rate case on January 5, 2007.*

2 *Douglas County PUD began the FERC integrated licensing process in 2004 and is progressing on schedule for a new license upon the current license expiration in May 2012.*

3 *PSE's share of power under the 2001 contract will decline over time as Grant County PUD's load increases. PSE's share of both the Priest Rapids and Wanapum developments was 0.8% at the end of 2011 and will not be less than 0.6% through 2052.*

OTHER ELECTRIC SUPPLY, EXCHANGE AND TRANSMISSION CONTRACTS AND AGREEMENTS

PSE purchases electric energy under long-term firm purchased power contracts with other utilities and marketers in the Western region. PSE is generally not obligated to make payments under these contracts unless power is delivered. PSE has seasonal energy and capacity exchange agreements with the BPA (for 42 average megawatts (aMW) of capacity) and with Pacific Gas & Electric Company (for 300 MW of capacity).

Pursuant to the provisions of the federal Public Utility Regulatory Policies Act (PURPA) and Washington state regulations, PSE also enters into long-term firm purchased power contracts with non-utility generators. PSE purchases the net electrical output of these projects at fixed and annually escalating prices, intended to approximate PSE's avoided cost of new generation projected at the time these agreements were made.

During 2011, PSE had agreements with March Point Cogeneration Company for 140 MW capacity of power output and 123 aMW of energy; and Tenaska Washington Partners, L.P. for 245 MW capacity of power output and 216 aMW of energy. Both contracts expired December 31, 2011 and there is no obligation to extend the contracts.

Further, PSE has entered into multiple various-term transmission contracts with other utilities to integrate electric generation and contracted resources into PSE's system. These transmission contracts require PSE to pay for transmission service based on the contracted MW level of demand, regardless of actual use.

Other transmission agreements provide actual capacity ownership or capacity ownership rights. PSE's annual charges under these agreements are also based on contracted MW volumes. Capacity on these agreements that is not committed to serve PSE's load is available for sale to third parties. PSE also purchases short-term transmission services from a variety of providers, including the BPA.

In 2011, PSE had 4,020 MW and 619 MW of total transmission demand contracted with the BPA and other utilities, respectively. PSE's remaining transmission capacity needs are met via PSE owned transmission assets.

NATURAL GAS SUPPLY FOR ELECTRIC CUSTOMERS

PSE purchases natural gas supplies for its power portfolio to meet demand for its combustion turbine generators. Supplies range from long-term to daily agreements, as the demand for the turbines varies depending on market heat rates. Purchases are made from a diverse group of major and independent natural gas producers and marketers in the United States and Canada. PSE also enters into physical and financial fixed price derivative instruments to hedge the cost of natural gas. PSE utilizes natural gas storage capacity that is dedicated to and paid for by the power portfolio to facilitate increased natural gas supply reliability and intra-day dispatch of PSE's gas-fired generation resources. During 2011, approximately 83.0% of natural gas for power purchased by PSE for power customers originated in British Columbia and 17.0% originated in the United States. Natural gas is either marketed outside PSE's service territory (off-system sales) or injected into the power portfolio's natural gas storage when the natural gas is not needed for the combustion turbines.

INTEGRATED RESOURCE PLANS, RESOURCE ACQUISITION AND DEVELOPMENT

PSE is required by Washington Commission regulations to file electric and natural gas Integrated Resource Plans (IRP) every two years with the next IRP scheduled to be filed by May 30, 2013. PSE filed its most recent IRP with the Washington Commission on May 30, 2011. The 2011 IRP demonstrated PSE's continuing need to acquire significant amounts of new generating resources, driven primarily by the expiration of existing power purchase contracts and by the requirements of the state's renewable portfolio standard. The 2011 IRP, as filed, identified the following capacity needs:

	2012	2013	2014	2015
Projected MW shortfall	917	1,050	1,203	1,203

To meet these expected shortfalls, the 2011 IRP identified a mix of energy efficiency programs, additional renewable resources (primarily wind) and base-load natural gas-fired generation to meet the growing needs of PSE's customers. The specific resources acquired will be determined through the Company's resource acquisition program which examines specific acquisition and development opportunities.

With the planned addition of the Lower Snake River Project Phase 1, PSE has enough renewable resources to meet statutory renewable resource requirements through 2020. The 2009 and 2011 IRP confirmed that there is a cost benefit to customers of building ahead of renewable need and taking advantage of expiring tax incentives rather than waiting until there is a statutory need to develop more renewable energy. In 2009, PSE purchased from RES America, Inc., all of the undivided interest in four development-stage wind projects, collectively known as the Lower Snake River wind project in Columbia and Garfield counties in Washington state. PSE is currently completing construction of Phase 1 of the Lower Snake River wind project, which will total 343 MW of capacity when complete in the first quarter of 2012.

NATURAL GAS UTILITY OPERATING STATISTICS

	YEAR ENDED DECEMBER 31,		
	2011	2010	2009
Gas operating revenue by classes (dollars in thousands):			
Residential	$ 760,442	$ 648,649	$ 795,756
Commercial firm	303,267	262,735	303,989
Industrial firm	32,222	28,939	36,141
Interruptible	43,704	42,413	56,511
Total retail gas sales	1,139,635	982,736	1,192,397
Transportation services	15,017	14,082	13,014
Other	14,198	14,713	19,334
Total gas operating revenue	$ 1,168,850	$ 1,011,531	$ 1,224,745
Number of customers served (average):			
Residential	700,039	694,086	689,438
Commercial firm	53,676	53,703	54,022
Industrial firm	2,465	2,489	2,534
Interruptible	356	381	398
Transportation	175	152	140
Total customers	756,711	750,811	746,532
Gas volumes, therms (thousands):			
Residential	597,471	519,527	585,626
Commercial firm	270,300	239,693	248,321
Industrial firm	32,346	29,812	31,535
Interruptible	54,163	52,771	59,222
Total retail gas volumes, therms	954,280	841,803	924,704
Transportation volumes	224,330	205,516	210,243
Total volumes	1,178,610	1,047,319	1,134,947
Working gas volumes in storage at year end, therms (thousands):			
Jackson Prairie	85,506	70,213	66,948
Clay Basin	89,123	86,891	93,023
Average therms used per customer:			
Residential	853	749	849
Commercial firm	5,036	4,463	4,597
Industrial firm	13,122	11,978	12,445
Interruptible	152,143	138,507	148,799
Transportation	1,281,884	1,352,079	1,501,739
Average revenue per customer:			
Residential	$ 1,086	$ 935	$ 1,154
Commercial firm	5,650	4,892	5,627
Industrial firm	13,072	11,627	14,262
Interruptible	122,763	111,320	141,987
Transportation	85,810	92,645	92,957
Average revenue per therm sold:			
Residential	$ 1.273	$ 1.249	$ 1.359
Commercial firm	1.122	1.096	1.224
Industrial firm	0.996	0.971	1.146
Interruptible	0.807	0.804	0.954
Average retail revenue per therm sold	1.194	1.167	1.289
Transportation	0.067	0.069	0.062
Heating degree days	5,146	4,549	4,897
Percent of normal – NOAA 30-year average	107.3%	94.8%	102.1%

NATURAL GAS SUPPLY FOR NATURAL GAS CUSTOMERS

PSE purchases a portfolio of natural gas supplies ranging from long-term firm to daily from a diverse group of major and independent natural gas producers and marketers in the United States and Canada. PSE also enters into physical and financial fixed-price derivative instruments to hedge the cost of natural gas to serve its customers. All of PSE's natural gas supply is ultimately transported through the facilities of Northwest Pipeline GP (NWP), the sole interstate pipeline delivering directly into PSE's service territory. Accordingly, delivery of natural gas supply to PSE's natural gas system is dependent upon the reliable operations of NWP.

	At December 31			
	2011		2010	
Peak Firm Natural Gas Supply [1]	Dth per Day	%	Dth per Day	%
Purchased gas supply:				
British Columbia	190,000	21.9	199,000	21.3
Alberta	70,000	8.0	70,000	7.5
United States	120,000	13.8	177,000	18.9
Total purchased natural gas supply	380,000	43.7%	446,000	47.7%
Purchased storage capacity:				
Jackson Prairie	58,000	6.7	58,000	6.2
Plymouth liquefied natural gas	70,500	8.1	70,500	7.5
Total purchased storage capacity	128,500	14.8%	128,500	13.7%
Owned storage capacity:				
Jackson Prairie	348,700	40.1	348,700	37.3
Propane and LNG	12,500	1.4	12,500	1.3
Total owned storage capacity	361,200	41.5%	361,200	38.6%
Total peak firm natural gas supply	869,700	100.0%	935,700	100.0%
Other and commitments with third parties	(14,400)		(15,500)	
Total net peak firm natural gas supply	855,300		920,200	

[1] *All peak firm gas supplies and storage are connected to PSE's market with firm transportation capacity.*

For baseload, peak management and supply reliability purposes, PSE supplements its firm natural gas supply portfolio by purchasing natural gas in off-peak periods, injecting it into underground storage facilities and withdrawing it during the peak winter heating season. Underground storage facilities at Jackson Prairie in western Washington and at Clay Basin in Utah are used for this purpose. Clay Basin withdrawals are used to supplant purchases from the U.S. Rocky Mountain supply region, while Jackson Prairie provides incremental peak-day resources utilizing storage redelivery transportation capacity. Jackson Prairie is also used for daily balancing of load requirements on PSE's gas system. Peaking needs are also met by; using PSE-owned natural gas held in NWP's liquefied natural gas (LNG) storage facility in Plymouth, Washington; using PSE-owned natural gas held in PSE's LNG peaking facility located within its distribution system in Gig Harbor, Washington; and interrupting service to customers on interruptible service rates.

PSE expects to meet its firm peak-day requirements for residential, commercial and industrial markets through its firm natural gas purchase contracts, firm transportation capacity, firm storage capacity and other firm peaking resources. PSE believes it will be able to acquire incremental firm natural gas supply and capacity to meet anticipated growth in the requirements of its firm customers for the foreseeable future.

During 2011, approximately 49.5% of natural gas supplies purchased by PSE for its gas customers originated in British Columbia, while 14.8% originated in Alberta and 35.7% originated in the United States. PSE's firm natural gas supply portfolio has adequate flexibility in its transportation arrangements to enable it to achieve savings when there are regional price differentials between natural gas supply basins. The geographic mix of suppliers and daily, monthly and annual take requirements permit some degree of flexibility in managing natural gas supplies during off-peak periods to minimize costs. Natural gas is marketed outside PSE's service territory (off-system sales) whenever on-system customer demand requirements permit and the resulting economics of these transactions are reflected in PSE's natural gas customer tariff rates through the PGA mechanism.

Natural Gas Storage Capacity

PSE holds storage capacity in the Jackson Prairie and Clay Basin underground natural gas storage facilities adjacent to NWP's pipeline to serve PSE's natural gas customers. The Jackson Prairie facility is operated and one-third owned by PSE. The facility is used primarily for intermediate peaking purposes since it is able to deliver a large volume of natural gas over a relatively short time period. Combined with capacity contracted from NWP's one-third stake in Jackson Prairie, PSE has peak firm withdrawal capacity in excess of 460,000 Dekatherm (Dth) per day, which, after reduction for a portion temporarily released to the power portfolio represents nearly 46.8% of PSE's expected near-term peak-day requirement.

PSE's total firm storage capacity of the facility is in excess of 10 million Dth. The location of the Jackson Prairie facility in PSE's market area increases supply reliability and provides significant pipeline demand cost savings by reducing the amount of annual pipeline capacity required to meet peak-day natural gas requirements. PSE has been expanding the storage capacity at Jackson Prairie since March 2003. The most recent withdrawal capacity expansion was placed in service in November 2008 and the reservoir expansion activities will continue through 2012. The owned storage capacity at Jackson Prairie was 8.4 million Dth at December 31, 2011. Once the expansion activities have been completed in 2012, the capacity will be 8.5 million Dth.

Due to the recent expansion of Jackson Prairie storage withdrawal capacity and storage capacity, PSE's natural gas storage resources are expected to exceed natural gas customer requirements for the next few years. Therefore, beginning in 2008 and continuing into 2014, 50,000 Dth per day of natural gas storage withdrawal capacity and 500,000 Dth of natural gas storage capacity have been temporarily released at market sensitive rates to PSE's power portfolio, increasing natural gas supply reliability and facilitating intra-day dispatch of PSE's natural gas-fired generation resources.

The Clay Basin storage facility is a supply area storage facility that is used primarily to reduce portfolio costs through supply management efforts that take advantage of market price volatility, and provides system reliability. PSE holds over 12.8 million Dth of Clay Basin storage capacity and approximately 107,000 Dth per day of firm withdrawal capacity under two long-term contracts with remaining terms of one and eight years. PSE's maximum firm withdrawal capacity and total storage capacity at Clay Basin, net of releases, is over 82,000 Dth per day and exceeds 9.8 million Dth, respectively.

LNG and Propane-Air Resources

LNG and propane-air resources provide firm natural gas supply on short notice for short periods of time. Due to their typically high cost and slow cycle times, these resources are normally utilized as a last resort supply source in extreme peak-demand periods, typically during the coldest hours or days. PSE contracts for LNG storage services of 241,700 Dth of PSE-owned gas at NWP's Plymouth facility, which is approximately three and one-half day's supply at a maximum daily deliverability of 70,500 Dth. PSE owns and operates the Swarr vaporized propane-air station located in Renton, Washington which includes storage capacity for approximately 1.5 million gallons of propane. This propane-air injection facility is designed to deliver the equivalent of 10,000 Dth of natural gas per day for up to 12 days directly into PSE's distribution system. PSE owns and operates an LNG peaking facility in Gig Harbor, Washington, with total capacity of 10,600 Dth, which is capable of delivering the equivalent of 2,500 Dth of natural gas per day.

Natural Gas Transportation Capacity

PSE currently holds firm transportation capacity on pipelines owned by NWP, Gas Transmission Northwest (GTN), Nova Gas Transmission (NOVA), Foothills Pipe Lines (Foothills) and Westcoast Energy (Westcoast). GTN, NOVA, and Foothills are all TransCanada companies. PSE pays fixed monthly demand charges for the right, but not the obligation, to transport specified quantities of natural gas from receipt points to delivery points on such pipelines each day for the term or terms of the applicable agreements.

PSE holds approximately 522,000 Dth per day of capacity for its natural gas customers on NWP that provides firm year-round delivery to PSE's service territory. In addition, PSE holds approximately 524,000 Dth per day of seasonal firm capacity on NWP to provide for delivery of natural gas stored in Jackson Prairie and the Plymouth LNG facility during the heating season. PSE has firm transportation capacity on NWP through various contracts that supply electric generating facilities with approximately 168,000 Dth per day. PSE participates in the pipeline capacity release market to achieve savings for PSE's customers and has released certain segments of temporarily surplus firm capacity to third parties. PSE's firm transportation capacity contracts with NWP have remaining terms ranging from one to 33 years. However, PSE has either the unilateral right to extend the contracts under the contracts' current terms or the right of first refusal to extend such contracts under current FERC rules.

PSE's firm transportation capacity for its natural gas customers on Westcoast's pipeline is approximately 130,000 Dth per day under various contracts, with remaining terms of one to seven years. PSE has other firm transportation capacity on Westcoast's pipeline, which supplies the electric generating facilities, totaling approximately 73,000 Dth per day, with remaining terms of three to seven years. PSE has firm transportation capacity on NOVA and Foothills pipelines, totaling approximately 80,000 Dth per day, with remaining terms of two to 12 years. PSE has annual renewal rights on this capacity. PSE's firm transportation capacity on the GTN pipeline, totaling approximately 90,000 Dth per day, has a remaining term of 12 years.

Capacity Release

The FERC regulates the release of firm pipeline and storage capacity for facilities which fall under its jurisdiction. Capacity releases allow shippers to temporarily or permanently relinquish unutilized capacity to recover all or a portion of the cost of such capacity. The FERC allows capacity to be released through several methods including open bidding and pre-arrangement. PSE has acquired some firm pipeline and storage service through capacity release provisions to serve its growing service territory and electric generation portfolio. PSE also mitigates a portion of the demand charges related to unutilized storage and pipeline capacity through capacity release. Capacity release benefits derived from the natural gas customer portfolio are passed on to PSE's natural gas customers through the PGA mechanism.

ENERGY EFFICIENCY

PSE is required under Washington state law to pursue feasible, achievable cost-effective electric conservation. PSE offers programs designed to help new and existing residential, commercial and industrial customers use energy efficiently. PSE uses a variety of mechanisms including cost-effective financial incentives, information and technical services to enable customers to make energy efficient choices with respect to building design, equipment and building systems, appliance purchases and operating practices. As described below, PSE recovers the actual costs of electric and natural gas energy efficiency programs through a tracker mechanism (for natural gas) and a rider mechanism (for electric). However, the tracker and rider mechanisms do not provide for any cost recovery of lost sales margin associated with reduced energy sales. A lost margin adjustment is included in PSE's pending general rate case.

PSE's rates are designed to capture most of the approved revenue requirements for fixed costs through volumetric rates. PSE fully recovers these costs only if its customers consume a certain level of natural gas and electricity. This level of consumption is typically established in the utility's most recently completed rate case based upon historical natural gas and electric volumes. When customers use less natural gas or electricity, whether due to conservation, weather or economic conditions, PSE's financial performance is negatively impacted because recovery of fixed costs is reduced in proportion to the reduction in natural gas or electric sales.

Since 1995, PSE has been authorized by the Washington Commission to defer natural gas energy efficiency (or conservation) expenditures and recover them through a tracker mechanism. The tracker mechanism allows PSE to defer efficiency expenditures and recover them in rates over the subsequent year. The tracker mechanism also allows PSE to recover an allowance for funds used to conserve energy on any outstanding balance that is not currently being recovered in rates.

Since May 1997, PSE has recovered direct electric energy efficiency (or conservation) expenditures through a rider mechanism. The rider mechanism allows PSE to defer the efficiency expenditures and amortize them to expense as PSE collects the efficiency expenditures in rates over a one-year period. As a result of the rider mechanism, direct electric energy efficiency expenditures are recovered. PSE does not earn a return on unamortized balances.

ENVIRONMENT

PSE's operations, including generation, transmission, distribution, service and storage facilities, are subject to environmental laws and regulations by federal, state and local authorities. The primary areas of environmental law that have the potential to most significantly impact PSE's operations and costs include:

Air and Climate Change Protection

PSE owns numerous thermal generation facilities, including seven natural gas plants and an ownership percentage of a coal plant in Colstrip, Montana (Colstrip). All these facilities are governed by the Clean Air Act (CAA) and all have CAA Title V operation permits that must be renewed every five years. These facilities also emit greenhouse gases (GHGs), and thus are also subject to any current or future GHG or climate change legislation or regulation. Colstrip represents PSE's most significant source of GHG emissions.

Species Protection

PSE owns three hydroelectric plants and three wind farms and numerous miles of above ground electric distribution and transmission lines which can be impacted by laws related to species protection. A number of species of fish have been listed as threatened or endangered under the Endangered Species Act (ESA), which influences hydroelectric operations, and may affect PSE operations, potentially representing cost exposure and operational constraints. Similarly, there are a number of avian and terrestrial species that have been listed as threatened or endangered under the ESA or are protected by the Migratory Bird Act. Designations of protected species under these two laws have the potential to influence operation of our wind farms and above ground transmission and distribution systems.

Remediation of Contamination

PSE and its predecessors are responsible for environmental remediation at various contaminated sites. These include properties currently and formerly owned by PSE, as well as third party owned properties in which hazardous substances were generated or released. Cleanup laws PSE may be subject to primarily include the Comprehensive Environmental Response, Compensation and Liability Act (federal) and the Model Toxics Control Act (state). These laws may hold liable any current or past owner, or operator of a contaminated site, as well as, any generator, arranger, transporter or disposer of regulated substances.

Hazardous and Solid Waste and PCB Handling and Disposal

Related to certain operations, including power generation and transmission and distribution maintenance, PSE must handle and dispose of certain hazardous and solid wastes, as well as, Polychlorinated Biphenyls (PCB) contaminated wastes. These actions are regulated by the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act (federal), the Toxic Substances Control Act (federal), and the dangerous waste regulations (state) that impose complex requirements on handling and disposing of regulated substances.

Water Protection

PSE facilities that discharge wastewater or storm water, or store bulk petroleum products are governed by the Clean Water Act (federal and state) which includes the Oil Pollution Act amendments. This includes most all generation facilities (all of which have water discharges and some of which have bulk fuel storage), and due to recent changes in state storm water regulations also includes many other facilities and construction projects depending on drainage, facility or construction activities, and chemical, petroleum and material storage.

Siting New Facilities

In siting new generation, transmission or distribution, PSE is subject to the State Environmental Policy Act, and may be subject to the federal National Environmental Policy Act, if there is a federal nexus, as well as, other local siting and zoning ordinances. These requirements may potentially require mitigation of environmental impacts to the fullest extent possible as well as other measures that can add significant cost to new facilities.

RECENT AND FUTURE ENVIRONMENTAL LAW AND REGULATION

Recent and future environmental law and regulations may be imposed at a federal, state or local level and may have a significant impact on cost of PSE operations. PSE monitors legislative and regulatory developments for environmental issues with the potential to alter the operation and cost of our generation plants, transmission and distribution system, and other assets. Recent, pending and potential future environmental law and regulations with the most significant potential impacts to PSE's operations and costs are described below.

Climate Change and Greenhouse Gas Emissions

PSE recognizes the growing concern that increased atmospheric concentrations of GHG contribute to climate change. PSE believes that climate change is an important issue that requires careful analysis and considered responses. A climate policy continues to evolve at the state and federal levels and PSE remains involved in state, regional and federal policymaking activities. PSE will continue to monitor the development of any climate change or climate change related air emission reduction initiative at the state and western regional levels. PSE will also consider the impact of any future legislation or new government regulation on the cost of generation in its IRP process.

Most recent definitive federal legislative activity on climate change occurred in June 2009; the United States House of Representatives passed H.R. 2454, the American Clean Energy and Security Act. The bill implements a cap-and-trade system of allowances to reduce GHG emissions 17.0% below 2005 levels by 2020, reaching an eventual target of 83.0% below 2005 levels by 2050. However, the 111th Congress ended without enacting any major law to limit or reduce GHG emissions.

Recent federal climate change regulation includes the Tailoring Rule, which became effective January 2, 2011. Under the rule, new sources that emit more than 100,000 tpv of total GHG and major modifications of existing sources that increase GHG emissions by 74,000 tpv will be required to implement Best Available Control Technology (BACT) to control GHG emissions. Potential impacts on Colstrip are being evaluated and impacts to our gas fleet cannot yet be determined.

Beginning on March 31, 2011, PSE is required to submit, on an annual basis, a report of its GHG emissions to the Environmental Protection Agency (EPA) including a report of emissions from all individual power plants emitting over 25,000 tons per year of GHGs and from certain natural gas distribution operations. Capital investments to monitor GHGs from the power plants and in the distribution system are not required at this time. Since 2002, PSE has voluntarily undertaken an annual inventory of its GHG emissions associated with PSE's total electric retail load, which was 21.5 million MWh in 2011, served from a supply portfolio of owned and purchased resources. The most recent data indicate that PSE's total GHG emissions (direct and indirect) from its electric supply portfolio in 2009 were 14.4 million tons of carbon dioxide equivalent. Since 2009, new PSE generation facilities have resulted in combined GHG emissions of 591,935 tons of carbon dioxide equivalent. Approximately 36.4% of PSE's total GHG emissions in 2009 (approximately 5.3 million tons) were associated with PSE's ownership and contractual interests in Colstrip.

In November 2010, the EPA released two more GHG reporting rules affecting PSE. The first rule, commonly referred to as Subpart DD, requires owners and operators of electric power system facilities with a total nameplate capacity exceeding 17,820 pounds of sulfur hexafluoride to report emissions from its use of electrical transmission and distribution equipment. The second rule, commonly referred to as Subpart W, requires certain oil and natural gas operations, including distribution and storage, to report GHG emissions from leaks and certain combustions activities. PSE will submit the required information as part of its annual filing to the EPA beginning on March 31, 2012.

While Colstrip remains a significant portion of PSE's GHG emissions, Colstrip is an essential part of the diversified portfolio PSE owns and/or operates for its customers. Consequently, PSE's overall emissions strategy demonstrates a concerted effort to manage customers' needs with an appropriate balance of new renewable generation, existing generation owned and/or operated by PSE and significant energy efficiency efforts.

MERCURY AND AIR TOXICS EMISSIONS

The state of Montana issued regulations limiting mercury emissions from coal-fired plants in October 2006 (with a limit of 0.9 lbs/Trillion British thermal units (lbs/TBtu) for plants burning coal like that used at Colstrip) which took effect on January 1, 2010. Mercury control equipment has been installed at Colstrip and has operated at a level that meets the current Montana requirement. Compliance based on a rolling 12-month average was first confirmed in January 2011 and has continued to meet the requirement during each month of 2011.

The final version of EPA's Mercury and Air Toxics Standard, (MATS rule) was released December 21, 2011. The final rule provides some concessions to electric generators by providing extra compliance time in certain circumstances, but overall the final rule remains largely consistent with the agency's initial proposal in March 2011. MATS sets a new federal emission limitation for mercury (1.2 lb/TBtu), for acid gases, for other toxic metal using a particulate matter (PM) surrogate (0.03 lb/MMBtu), and for sulfur dioxide and nitrogen oxides for steam electric generating units. Colstrip is currently meeting the new mercury standards. Current emissions and available control technologies are currently being evaluated to determine what will be necessary to meet the new standards for acid gases and PM. PSE cannot yet determine the outcome of these analyses.

ADDITIONAL COLSTRIP EMISSION CONTROLS

On June 15, 2005, the EPA issued the Clean Air Visibility rule to address regional haze or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines Best Available Retrofit Technology (BART) requirements for electric generating units, including presumptive limits for sulfur dioxide, particulate matter and nitrogen oxide controls for large units. In February 2007, Colstrip was notified by the EPA that Colstrip Units 1 & 2 were determined to be subject to the EPA's BART requirements. A BART engineering analysis for Colstrip Units 1 & 2 was submitted in August 2007 and additional requested analyses were submitted in June 2008. On November 5, 2010, the EPA issued a request for additional reasonable progress information for Colstrip Units 3 & 4 which has been submitted. EPA has met with Colstrip representatives to discuss possible requirements for Units 1 & 2 to meet EPA's BART requirements, but nothing definitive has been determined. PSE cannot yet determine the outcome of these analyses or information requests.

COAL COMBUSTION RESIDUALS

On June 21, 2010, the EPA issued a proposed rulemaking for the "Identification and Listing of Special Wastes: Disposal of Coal Combustion Residuals from Electric Utilities" which proposes different regulatory mechanisms to regulate coal ash. The EPA received numerous comments on the respective proposals in November 2010, including comments from PSE and other Colstrip owners. The EPA has announced that a final rule will not be issued until 2012.

To date, EPA has proposed three regulatory options. Under the first two options, coal ash could be regulated as a solid waste under Subtitle D provisions of the Resource Conservation and Recovery Act (RCRA). This would give authority to the states to oversee a set of performance standards for handling and disposal. Coal ash would be listed as non-hazardous and would allow wet handling to continue, and it would allow continued use of surface impoundments provided they are equipped with protective liners. One of these two options would require significantly less modifications to closed, as well as, in-use impoundments.

Under the third option, coal ash could be regulated as a hazardous waste under Subtitle C provisions of the RCRA, which would make coal ash subject to a comprehensive program of federally enforceable requirements for waste management and disposal. Regulation under Subtitle C would essentially require the phase-out of wet handling and surface impoundments. The EPA estimates over 500 surface impoundments would be affected by this ruling. The EPA is expected to issue a final ruling in late 2012.

Impact to Colstrip operations and PSE, could range from minimal to significant. Due to the wide range in the options proposed by EPA PSE cannot determine impacts with any more certainty at this time, but we are involved with monitoring development of the final rule and advocating for reasonable approach that would be protective of the environment and cost-effective.

PCBS

On April 7, 2010, the EPA issued a Advance Notice of Proposed Rule Making (ANPRM) soliciting information on a broad range of questions concerning inventory, management, use, and disposal of PCB-containing equipment. EPA is using this ANPRM to seek data to better evaluate whether to initiate a rulemaking process geared toward a mandatory phase-out of all PCBs. This would likely remove all existing use authorizations for PCBs in electrical and gas pipeline equipment. As proposed, the ANPRM would mandate a phase out of in-service PCBs through a phased process with full removal achieved by 2025.

The end of the comment period for the ANPRM was initially July 6, 2010 but due to the volume of comments received, an extension was granted to August 20, 2010 with the suggested issuance of a Notice in May 2012. PSE provided comments through both the Utilities Solid Waste Advocacy Group (USWAG) as well as the American Gas Association (AGA). Upon receiving all comments, the EPA has rescheduled the issuance to April 2013. At this time, PSE cannot determine what the impacts of this ANPRM will have on its operations but will continue to work closely with USWAG and AGA to monitor developments and advocate for a reasonable approach that would be protective of the environment and cost-effective.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The executive officers of Puget Energy as of March 1, 2012 are listed below along with their business experience during the past five years. Officers of Puget Energy are elected for one-year terms.

NAME	AGE	OFFICES
K. J. Harris	47	President and Chief Executive Officer since March 1, 2011; President July 2010 – February 2011; Executive Vice President and Chief Resource Officer 2007 – 2010; Senior Vice President Regulatory Policy and Energy Efficiency 2005 – 2007.
D. A. Doyle	53	Senior Vice President and Chief Financial Officer since November 2011. Prior to PSE, he was President of Wisconsin Sports Development Corporation 2010 – November 2011; Vice President and Chief Financial Officer of American Transmission Company, LLC 2000 – 2009.
D. E. Gaines	55	Vice President Finance and Treasurer since March 2002.
S. R. Secrist	50	Vice President, General Counsel and Chief Ethics and Compliance Officer since January 2011; Interim General Counsel October 2010 – January 2011; Deputy General Counsel 2006 – October 2010.

The executive officers of PSE as of March 1, 2012 are listed below along with their business experience during the past five years. Officers of PSE are elected for one-year terms.

NAME	AGE	OFFICES
K. J. Harris	47	President and Chief Executive Officer since March 1, 2011; President July 2010 – February 2011; Executive Vice President and Chief Resource Officer 2007 – 2010; Senior Vice President Regulatory Policy and Energy Efficiency 2005 – 2007.
D. A. Doyle	53	Senior Vice President and Chief Financial Officer since November, 2011. Prior to PSE, he was President of Wisconsin Sports Development Corporation 2010 – November 2011; Vice President and Chief Financial Officer of American Transmission Company, LLC 2000 – 2009.
D. E. Gaines	55	Vice President Finance and Treasurer since March 2002.
S. McLain	55	Senior Vice President Delivery Operations since February 2011; Senior Vice President Operations 2003 – January 2011.
M. D. Mellies	51	Senior Vice President and Chief Administrative Officer since February 2011; Vice President Human Resources 2005 – January 2011.
S. R. Secrist	50	Vice President, General Counsel and Chief Ethics and Compliance Officer since January 2011; Interim General Counsel October 2010 – January 2011; Deputy General Counsel 2006 – October 2010.
P. M. Wiegand	59	Senior Vice President Energy Operations since February 2011; Senior Vice President Power Generation 2010 – January 2011; Vice President Power Generation 2007 – 2010; Vice President Project Development & Contract Management 2003 – 2007.

ITEM 1A. RISK FACTORS

The following risk factors, in addition to other factors and matters discussed elsewhere in this report, should be carefully considered. The risks and uncertainties described below are not the only risks and uncertainties that Puget Energy and PSE may face. Additional risks and uncertainties not presently known or currently deemed immaterial also may impair PSE's business operations. If any of the following risks actually occur, Puget Energy's and PSE's business, results of operations and financial conditions would suffer.

RISKS RELATING TO PSE'S BUSINESS

THE ACTIONS OF REGULATORS CAN SIGNIFICANTLY AFFECT PSE'S EARNINGS, LIQUIDITY AND BUSINESS ACTIVITIES.

The rates that PSE is allowed to charge for its services is the single most important item influencing its financial position, results of operations and liquidity. PSE is highly regulated and the rates that it charges its wholesale and retail customers are determined by both the Washington Commission and the FERC.

PSE is also subject to the regulatory authority of the Washington Commission with respect to accounting, operations, the issuance of securities and certain other matters, and the regulatory authority of the FERC with respect to the transmission of electric energy, the sale of electric energy at the wholesale level, accounting and certain other matters. Policies and regulatory actions by these regulators could have a material impact on PSE's financial position, results of operations and liquidity.

PSE'S RECOVERY OF COSTS IS SUBJECT TO REGULATORY REVIEW AND ITS OPERATING INCOME MAY BE ADVERSELY AFFECTED IF ITS COSTS ARE DISALLOWED.

The Washington Commission determines the rates PSE may charge to its electric retail customers based, in part, on historic test year costs plus normalized assumptions about rate year power costs, weather and hydrological conditions. Non-energy costs for natural gas retail customers are based on historic test year costs. If in a specific year PSE's costs are higher than what is allowed to be recovered in rates, revenue may not be sufficient to permit PSE to earn its allowed return or to cover its costs. In addition, the Washington Commission decides what level of expense and investment is reasonable and prudent in providing electric and natural gas service. If the Washington Commission decides that part of PSE's costs do not meet the standard, those costs may be disallowed partially or entirely and not recovered in rates. For the aforementioned reasons, the rates authorized by the Washington Commission may not be sufficient to earn the allowed return or recover the costs incurred by PSE in a given period.

THE PCA MECHANISM, BY WHICH VARIATIONS IN PSE'S POWER COSTS ARE APPORTIONED BETWEEN PSE AND ITS CUSTOMERS PURSUANT TO A GRADUATED SCALE, COULD RESULT IN SIGNIFICANT INCREASES IN PSE'S EXPENSES IF POWER COSTS ARE SIGNIFICANTLY HIGHER THAN THE BASELINE RATE.

PSE has a PCA mechanism that provides for recovery of power costs from customers or refunding of power cost savings to customers, as those costs vary from the "power cost baseline" level of power costs which are set, in part, based on normalized assumptions about weather and hydrological conditions. Excess power costs or power cost savings will be apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism. As a result, if power costs are significantly higher than the baseline rate, PSE's expenses could significantly increase.

PSE MAY BE UNABLE TO ACQUIRE ENERGY SUPPLY RESOURCES TO MEET PROJECTED CUSTOMER NEEDS OR MAY FAIL TO SUCCESSFULLY INTEGRATE SUCH ACQUISITIONS.

PSE projects that future energy needs will exceed current purchased and Company owned and controlled power resources. As part of PSE's business strategy, it plans to acquire additional electric generation and delivery infrastructure to meet customer needs. If PSE cannot acquire additional energy supply resources at a reasonable cost, it may be required to purchase additional power in the open market at a cost that could significantly increase its expenses thus reducing earnings and cash flows. Additionally, PSE may not be able to timely recover some or all of those increased expenses through ratemaking. While PSE expects to identify the benefits of new energy supply resources prior to their acquisition and integration, it may not be able to achieve the expected benefits of such energy supply sources.

PSE'S CASH FLOW AND EARNINGS COULD BE ADVERSELY AFFECTED BY POTENTIAL HIGH PRICES AND VOLATILE MARKETS FOR PURCHASED POWER, INCREASED CUSTOMER DEMAND FOR ENERGY, RECURRENCE OF LOW AVAILABILITY OF HYDROELECTRIC RESOURCES, OUTAGES OF ITS GENERATING FACILITIES OR A FAILURE TO DELIVER ON THE PART OF ITS SUPPLIERS.

The utility business involves many operating risks. If PSE's operating expenses, including the cost of purchased power and natural gas, significantly exceed the levels recovered from retail customers, its cash flow and earnings would be negatively affected. Factors which could cause purchased power and natural gas costs to be higher than anticipated include, but are not limited to, high prices in western wholesale markets during periods when PSE has insufficient energy resources to meet its load requirements and/or high volumes of energy purchased in wholesale markets at prices above the amount recovered in retail rates due to:

- Below normal energy generated by PSE-owned hydroelectric resources due to low streamflow conditions or precipitation;
- Extended outages of any of PSE-owned generating facilities or the transmission lines that deliver energy to load centers;
- Failure to perform on the part of any party from which PSE purchases capacity or energy; and
- The effects of large-scale natural disasters on a substantial portion of distribution infrastructure.

PSE'S ELECTRIC GENERATING FACILITIES ARE SUBJECT TO OPERATIONAL RISKS THAT COULD RESULT IN UNSCHEDULED PLANT OUTAGES, UNANTICIPATED OPERATION AND MAINTENANCE EXPENSES AND INCREASED POWER PURCHASE COSTS.

PSE owns and operates coal, natural gas-fired, hydroelectric, wind-powered and oil-fired generating facilities. Operation of electric generating facilities involves risks that can adversely affect energy output and efficiency levels. Included among these risks are:

- Increased prices for fuel and fuel transportation as existing contracts expire;
- Facility shutdowns due to a breakdown or failure of equipment or processes;
- Disruptions in the delivery of fuel and lack of adequate inventories;
- Labor disputes;
- Inability to comply with regulatory or permit requirements;
- Disruptions in the delivery of electricity;
- Operator error or safety related stoppages;
- Terrorist attacks; and
- Catastrophic events such as fires, explosions, floods or acts of nature.

IF PSE IS UNABLE TO PROTECT OUR INFORMATION TECHNOLOGY INFRASTRUCTURE AGAINST DATA CORRUPTION, CYBER-BASED ATTACKS OR NETWORK SECURITY BREACHES, OUR OPERATIONS COULD BE DISRUPTED.

PSE operates in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite our implementation of security measures, our technology systems are vulnerable to disability, failures or unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. If our technology systems were to fail or be breached and we were unable to recover in a timely manner, we may be unable to fulfill critical business functions and sensitive, confidential and other data could be compromised, which could have a material adverse effect on our results of operations, financial condition and cash flows. In addition, these cyber-based attacks could disrupt our ability to produce or distribute some portion of our energy products and could affect the reliability or operability of the electric and natural gas systems.

PSE IS SUBJECT TO THE COMMODITY PRICE, DELIVERY AND CREDIT RISKS ASSOCIATED WITH THE ENERGY MARKETS AS WELL AS TO SUPPLY AND PRICE RISKS AFFECTING PSE'S CONSTRUCTION AND MAINTENANCE PROGRAMS.

In connection with matching loads and resources, PSE engages in wholesale sales and purchases of electric capacity and energy, and, accordingly, is subject to commodity price risk, delivery risk, credit risk and other risks associated with these activities. Credit risk includes the risk that counterparties owing PSE money or energy will breach their obligations. Should the counterparties to these arrangements fail to perform, PSE may be forced to enter into alternative arrangements. In that event, PSE's financial results could be adversely affected. Although PSE takes into account the expected probability of default by counterparties, the actual exposure to a default by a particular counterparty could be greater than predicted.

Further, as a consequence of its electric generation construction and reconstruction programs and investments in its electric and gas distribution systems, PSE contracts to purchase substantial quantities of steel, cable, and similar materials, and thus is subject to supply and price risks affecting these items. To lower its financial exposure related to commodity price fluctuations, PSE may use forward delivery agreements, swaps and option contracts to hedge commodity price risk with a diverse group of counterparties. However, PSE does not always cover the entire exposure of its assets or positions to market price volatility and the coverage will vary over time. To the extent PSE has unhedged positions or its hedging procedures do not work as planned, fluctuating commodity prices could adversely impact its results of operations.

COSTS OF COMPLIANCE WITH ENVIRONMENTAL, CLIMATE CHANGE AND ENDANGERED SPECIES LAWS ARE SIGNIFICANT AND THE COST OF COMPLIANCE WITH NEW AND EMERGING LAWS AND REGULATIONS AND THE INCURRENCE OF ASSOCIATED LIABILITIES COULD ADVERSELY AFFECT PSE'S RESULTS OF OPERATIONS.

PSE's operations are subject to extensive federal, state and local laws and regulations relating to environmental, including air and climate protection, endangered species protection, remediation of contamination, waste handling and disposal, water protection and siting new facilities. To comply with these legal requirements, PSE must spend significant sums of money on measures including resource planning, remediation, monitoring, analysis, mitigation measures, pollution control equipment and emissions related abatement and fees. New environmental laws and regulations affecting PSE's operations may be adopted, and new interpretations of existing laws and regulations could be adopted or become applicable to PSE or its facilities. Compliance with these or other future regulations could require significant expenditures by PSE and adversely affect PSE's financial position, results of operations, cash flows and liquidity. In addition, PSE may not be able to recover all of its costs for such expenditures through electric and natural gas rates at current levels in the future.

With respect to endangered species laws, the listing or proposed listing of several species of salmon in the Pacific Northwest is causing a number of changes to the operations of hydroelectric generating facilities on Pacific Northwest rivers, including the Columbia River. These changes could reduce the amount, and increase the cost, of power generated by hydroelectric plants owned by PSE, or in which PSE has an interest, and increase the cost of the permitting process for these facilities.

Under current law, PSE is also generally responsible for any on-site liabilities associated with the environmental condition of the facilities that it currently owns or operates or has previously owned or operated. The incurrence of a material environmental liability or the new regulations governing such liability could result in substantial future costs and have a material adverse effect on PSE's results of operations and financial condition.

Specific to climate change, Washington state has adopted both a renewable portfolio standard and greenhouse gas legislation, including an emission performance standard provision. PSE cannot yet determine the costs of compliance with the recently enacted legislation. Recent decisions related to climate change by the United States Supreme Court and the EPA, together with efforts by Congress, have drawn greater attention to this issue at the federal, state and local level. While PSE cannot yet determine costs associated with these or future decisions or potential future legislation, there may be a significant impact on the cost of carbon-intensive coal generation, in particular.

PSE'S OPERATING RESULTS FLUCTUATE ON A SEASONAL AND QUARTERLY BASIS.

PSE's business is seasonal and weather patterns can have a material impact on its revenue, expenses and operating results. Because natural gas is heavily used for residential and commercial heating, demand depends heavily on weather patterns in PSE's service territory, and a significant amount of natural gas revenue is recognized in the first and fourth quarters related to the heating season. However, conservation efforts may result in decreased customer demand, despite normal or lower than normal temperatures. Demand for electricity is also greater in the winter months associated with heating. Accordingly, PSE's operations have historically generated less revenue and income when weather conditions are milder in the winter. In the event that the Company experiences unusually mild winters, results of operations and financial condition could be adversely affected.

PSE MAY BE ADVERSELY AFFECTED BY EXTREME EVENTS IN WHICH PSE IS NOT ABLE TO PROMPTLY RESPOND AND REPAIR THE ELECTRIC AND GAS INFRASTRUCTURE SYSTEM.

PSE must maintain an emergency planning and training program to allow PSE to quickly respond to extreme events. Without emergency planning, PSE is subject to availability of outside contractors during an extreme event which may impact the quality of service provided to PSE's customers. In addition, a slow response to extreme events may have an adverse affect on earnings as customers may be without electricity and natural gas for an extended period of time.

PSE MAY BE NEGATIVELY AFFECTED BY ITS INABILITY TO ATTRACT AND RETAIN PROFESSIONAL AND TECHNICAL EMPLOYEES.

PSE's ability to implement a workforce succession plan is dependent upon PSE's ability to employ and retain skilled professional and technical workers. Without a skilled workforce, PSE's ability to provide quality service to PSE's customers and to meet regulatory requirements could affect PSE's earnings.

PSE DEPENDS ON AN AGING WORK FORCE AND THIRD PARTY VENDORS TO PERFORM CERTAIN IMPORTANT SERVICES.

PSE continues to be concerned about the availability and aging of skilled workers for special complex utility functions. PSE also hires third parties to perform a variety of normal business functions, such as power plant maintenance, data warehousing and management, electric transmission, electric and gas distribution construction and maintenance, certain billing and metering processes, call center overflow and credit and collections. The unavailability of skilled workers or unavailability of such vendors could adversely affect the quality and cost of PSE's gas and electric service and accordingly PSE's results of operations.

POOR PERFORMANCE OF PENSION AND POSTRETIREMENT BENEFIT PLAN INVESTMENTS AND OTHER FACTORS IMPACTING PLAN COSTS COULD UNFAVORABLY IMPACT PSE'S CASH FLOW AND LIQUIDITY.

PSE provides a defined benefit pension plan to PSE employees and postretirement benefits to certain PSE employees and former employees. Costs of providing these benefits are based in part on the value of the plan's assets and therefore, continued adverse market performance could result in lower rates of return for the investments that fund PSE's pension and postretirement benefits plans and could increase PSE's funding requirements related to the pension plans. Any contributions to PSE's plans in 2012 and beyond as well as the timing of the recovery of such contributions in general rate cases could impact PSE's cash flow and liquidity.

PSE MAY BE ADVERSELY AFFECTED BY ITS INABILITY TO SUCCESSFULLY IMPLEMENT CERTAIN TECHNOLOGY PROJECTS.

PSE is currently undertaking a multi-year Company-wide business process modernization effort which will replace existing software PSE currently uses for processing customer records and billing, mapping infrastructure assets and handling outage management tasks. These projects, are expected to be fully deployed by 2013, include: (1) a new Customer Information System intended to replace a PSE application that manages customer information and tracks outages; (2) a new Geospatial Information System intended to replace existing maps of our natural gas transmission and distribution systems with electronic databases; and (3) an Outage Management System expected to augment and improve PSE's ability to pinpoint the sources of electric system outages and respond to them more quickly, focus repair efforts and more accurately predict restoration times. Implementation of these information systems is complex, expensive and time consuming. If PSE does not successfully implement the new systems and new processes, or if the systems do not operate as intended, it could result in substantial disruptions to PSE's business, which could have a material adverse effect on our results of operations and financial condition.

RISKS RELATING TO PUGET ENERGY AND PSE OPERATIONS

THE COMPANY'S BUSINESS IS DEPENDENT ON ITS ABILITY TO SUCCESSFULLY ACCESS CAPITAL.

The Company relies on access to internally generated funds, bank borrowings through multi-year committed credit facilities and short-term money markets as sources of liquidity and longer-term debt markets to fund PSE's utility construction program and other capital expenditure requirements of PSE. If Puget Energy or PSE are unable to access capital on reasonable terms, their ability to pursue improvements or acquisitions, including generating capacity, which may be relied on for future growth and to otherwise implement its strategy, could be adversely affected. Capital and credit market disruptions, a downgrade of Puget Energy's or PSE's credit rating or the imposition of restrictions on borrowings under their credit facilities in the event of a deterioration of financial ratios, may increase Puget Energy's and PSE's cost of borrowing or adversely affect the ability to access one or more financial markets.

THE AMOUNT OF THE COMPANY'S DEBT COULD ADVERSELY AFFECT ITS LIQUIDITY AND RESULTS OF OPERATIONS.

Puget Energy and PSE have short-term and long-term debt, and may incur additional debt (including secured debt) in the future. Puget Energy has access to a multi-year $1.0 billion revolving credit facility, secured by substantially all of its assets, of which $864.0 million was outstanding as of February 10, 2012. PSE has access to three unsecured credit facilities that provide, in the aggregate $1.15 billion in short-term borrowing capability. In addition, Puget Energy has issued $950.0 million in senior secured notes, whereas PSE, as of December 31, 2011 had approximately $3.8 billion outstanding under first mortgage bonds, pollution control bonds, senior notes and junior subordinated notes. The Company's debt level could have important effects on the business, including but not limited to:

- making it difficult to satisfy obligations under the debt agreements and increasing the risk of default on the debt obligations;
- making it difficult to fund non-debt service related operations of the business; and
- limit the Company's financial flexibility, including its ability to borrow additional funds on favorable terms or at all.

A DOWNGRADE IN PUGET ENERGY'S OR PSE'S CREDIT RATING COULD NEGATIVELY AFFECT THE ABILITY TO ACCESS CAPITAL AND THE ABILITY TO HEDGE IN WHOLESALE MARKETS.

Although neither Puget Energy nor PSE has any rating downgrade provisions in its credit facilities that would accelerate the maturity dates of outstanding debt, a downgrade in the Companies' credit ratings could adversely affect the ability to renew existing or obtain access to new credit facilities and could increase the cost of such facilities. For example, under Puget Energy's and PSE's facilities, the borrowing spreads over the London Interbank Offered Rate (LIBOR) and commitment fees increase if their respective corporate credit ratings decline. A downgrade in commercial paper ratings could increase the cost of commercial paper and limit or preclude PSE's ability to issue commercial paper under its current programs.

Any downgrade below investment grade of PSE's corporate credit rating could cause counterparties in the wholesale electric, wholesale natural gas and financial derivative markets to request PSE to post a letter of credit or other collateral, make cash prepayments, obtain a guarantee agreement or provide other mutually agreeable security, all of which would expose PSE to additional costs.

THE COMPANY MAY BE NEGATIVELY AFFECTED BY UNFAVORABLE CHANGES IN THE TAX LAWS OR THEIR INTERPRETATION.

Changes in tax law, related regulations or differing interpretation or enforcement of applicable law by the IRS or other taxing jurisdiction could have a material adverse impact on the Company's financial statements. The tax law, related regulations and case law are inherently complex. The Company must make judgments and interpretations about the application of the law when determining the provision for taxes. Disputes over interpretations of tax laws may be settled with the taxing authority in examination, upon appeal or through litigation. The Company's tax obligations include income, real estate, public utility, municipal, sales and use, business and occupation and employment-related taxes and ongoing appeals issues related to these taxes. These judgments may include reserves for potential adverse outcomes regarding tax positions that may be subject to challenge by the taxing authorities.

POTENTIAL LEGISLATION AND REGULATORY ACTIONS COULD INCREASE THE COMPANY'S COSTS, REDUCE THE COMPANY'S REVENUE AND CASH FLOW, OR OTHERWISE ALTER THE WAY THE COMPANY CONDUCTS BUSINESS.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank) was signed into law. Title VII of the Dodd-Frank law gave regulators including the Commodities Futures Trading Commission (CFTC) and the Securities Exchange Commission the authority to create new oversight structures for derivative financial instruments, which were widely thought to have contributed to the 2008 financial crisis. The new legislation of certain over-the-counter swaps could expand collateral requirements of swaps, which may make it more costly for companies and/or limit the Company's ability to enter into such transactions. The Dodd-Frank amended section 2(h)(7) of the Commodities Exchange Act to provide an elective exemption from the clearing requirements of Title VII of the Dodd-Frank Act for any entity that is not a financial entity, is using swaps to hedge or mitigate commercial risk, and notifies the CFTC, in a manner set forth by the CFTC, how it generally meets its financial obligations associated with entering into non-cleared swaps. The Company is evaluating the legislation and the CFTC's implementation of it to determine its impact, if any, on the Company's hedging program, results of operations and liquidity. The Company will not know the full impact of the new legislation until the regulations are finalized.

RISKS RELATING TO PUGET ENERGY'S CORPORATE STRUCTURE

AS A HOLDING COMPANY, PUGET ENERGY DEPENDS ON PSE'S ABILITY TO PAY DIVIDENDS.

As a holding company with no significant operations of its own, the primary source of funds for the repayment of debt and other expenses, as well as payment of dividends to its shareholder, is cash dividends PSE pays to Puget Energy. PSE is a separate and distinct legal entity and has no obligation to pay any amounts to Puget Energy, whether by dividends, loans or other payments. The ability of PSE to pay dividends or make distributions to Puget Energy, and accordingly, Puget Energy's ability to pay dividends or repay debt or other expenses, will depend on PSE's earnings, capital requirements and general financial condition. If Puget Energy does not receive adequate distributions from PSE, it may not be able to meet its obligations or pay dividends.

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE's electric and natural gas mortgage indentures. In addition, beginning February 6, 2009, pursuant to the terms of the Washington Commission merger order, PSE may not declare or pay dividends if PSE's common equity ratio, calculated on a regulatory basis, is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. Also, pursuant to the merger order, PSE may not declare or make any distribution, unless on the date of distribution PSE's corporate credit/issuer rating is investment grade, or if its credit ratings are below investment grade, PSE's ratio of Earnings Before Interest, Tax, Depreciation and Amortization (EBITDA) to interest expense for the four most recently ended fiscal quarters prior to such date is equal to or greater than three to one. The common equity ratio, calculated on a regulatory basis, was 48.2% at December 31, 2011 and the EBITDA to interest expense was 4.4 to 1.0 for the 12 months then ended.

PSE's ability to pay dividends is also limited by the terms of its credit facilities, pursuant to which PSE is not permitted to pay dividends during any Event of Default, or if the payment of dividends would result in an Event of Default (as defined in the facilities), such as failure to comply with certain financial covenants.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The principal electric generating plants and underground natural gas storage facilities owned by PSE are described under Item 1, Business – Electric Supply and Gas Supply. PSE owns its transmission and distribution facilities and various other properties. Substantially all properties of PSE are subject to the liens of PSE's mortgage indentures. The Company's corporate headquarters is housed in a leased building located in Bellevue, Washington.

ITEM 3. LEGAL PROCEEDINGS

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. The following is a description of legal proceedings that are material to PSE’s operations:

Residential Exchange. The Northwest Power Act, through the Residential Exchange Program (REP), provides access to the benefits of low-cost federal hydroelectric power to residential and small farm customers of regional utilities, including PSE. The program is administered by the Bonneville Power Administration (the BPA). Pursuant to agreements (including settlement agreements) between the BPA and PSE, the BPA has provided payments of REP benefits to PSE, which PSE has passed through to its residential and small farm customers in the form of electricity bill credits.

In 2007, the U.S. Court of Appeals for the Ninth Circuit ruled that REP agreements of the BPA with PSE and a number of other investor-owned utilities were inconsistent with the Northwest Power Act. Since that time, those investor-owned utilities, including PSE, the BPA and other parties have been involved in ongoing litigation at the Ninth Circuit relating to the amount of REP benefits paid to utilities, including PSE, for the period fiscal year 2002 through fiscal year 2011 and the amount of REP benefits to be paid going forward.

In July 2011, the BPA, PSE and a number of other parties entered into a settlement agreement that by its terms if upheld in their entirety would resolve the disputes between BPA and PSE regarding REP benefits paid for the period fiscal year 2002-fiscal year 2011. In October 2011, certain other parties challenged BPA decisions with regard to its entering into this most recent settlement agreement. Pending disposition of this challenge, the other pending Ninth Circuit litigation regarding REP benefits for the period fiscal year 2002 through fiscal year 2011 has been stayed by the Ninth Circuit.

Due to the pending and ongoing proceedings, PSE is unable to reasonably estimate any amounts of REP payments – either to be recovered by the BPA or to be paid for any future periods to PSE – and is unable to determine the impact, if any, these proceedings and litigation may have on PSE. However, it is unlikely that any unfavorable outcome would have a material adverse effect on PSE because REP benefits received by PSE are passed through to PSE's residential and small farm customers.

Pacific Northwest Refund Proceeding. In October 2000, PSE filed a complaint with the FERC (Docket No. EL01-10) against “all jurisdictional sellers” in the Pacific Northwest seeking prospective price caps consistent with any result the FERC ordered for the California markets. The FERC issued an order including price caps in July 2001, and PSE moved to dismiss the proceeding. In response to PSE’s motion, various entities intervened and sought to convert PSE’s complaint into one seeking retroactive refunds in the Pacific Northwest. The FERC rejected that effort, after holding what the FERC referred to as a “preliminary evidentiary hearing” before an administrative law judge. On October 3, 2011, after appellate reviews, the FERC issued an Order on Remand and set the matter for hearing before an administrative law judge, but first requiring the parties to engage in settlement talks that began in the fall of 2011. As such, the hearing date itself is not known. PSE intends to vigorously defend its position but is unable to predict the outcome of this matter.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

All of the outstanding shares of Puget Energy's common stock, the only class of common equity of Puget Energy, are held by its direct parent Puget Equico, which is an indirect wholly-owned subsidiary of Puget Holdings. The outstanding shares of PSE's common stock, the only class of common equity of PSE, are held by Puget Energy and are not publicly traded.

The payment of dividends on PSE common stock to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE's mortgage indentures in addition to terms of the Washington Commission merger order. Puget Energy's ability to pay dividends is also limited by the merger order issued by the Washington Commission as well as by the terms of its credit facilities. For further discussion, see Item 1A, Risk Factors, Risks relating to Puget Energy's Corporate Structure and Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations included in this report.

ITEM 6. SELECTED FINANCIAL DATA

The following tables show selected financial data. This information should be read in conjunction with the Management Discussion and Analysis and the audited consolidated financial statements and the related notes, included in Items 7 and 8 of this report, respectively.

PUGET ENERGY SUMMARY OF OPERATIONS (DOLLARS IN THOUSANDS)	SUCCESSOR [1] YEAR ENDED DECEMBER 31, 2011	SUCCESSOR [1] YEAR ENDED DECEMBER 31, 2010	SUCCESSOR [1] FEBRUARY 6, 2009 - DECEMBER 31, 2009	PREDECESSOR [1] JANUARY 1, 2009 - FEBRUARY 5, 2009	PREDECESSOR [1] YEAR ENDED DECEMBER 31, 2008	PREDECESSOR [1] YEAR ENDED DECEMBER 31, 2007
Operating revenue	$ 3,318,765	$ 3,122,217	$ 2,925,148	$ 403,713	$3,357,773	$3,220,147
Operating income	474,940	308,234	474,863	35,410	382,748	441,034
Income from continuing operations	123,290	30,311	174,015	12,756	154,929	184,676
Net income	123,290	30,311	174,015	12,756	154,929	184,464
Basic earnings per common share from continuing operations	N/A	N/A	N/A	N/A	1.20	1.57
Basic earnings per common share	N/A	N/A	N/A	N/A	1.20	1.57
Diluted earnings per common share from continuing operations	N/A	N/A	N/A	N/A	1.19	1.56
Diluted earnings per common share	N/A	N/A	N/A	N/A	1.19	1.56
Dividends per common share	N/A	N/A	N/A	N/A	$ 1.00	$ 1.00
Book value per common share	N/A	N/A	N/A	N/A	17.53	19.45
Total assets at year end	$12,384,710	$11,929,336	$11,900,140	$8,594,836	$8,434,102	$7,598,736
Long-term debt	5,027,367	4,132,713	3,790,698	2,520,860	2,270,860	2,428,860
Preferred stock subject to mandatory redemption	--	--	--	--	1,889	1,889
Junior subordinated notes	250,000	250,000	250,000	250,000	250,000	250,000
Capital lease obligations	32,207	42,603	134,229	68,293	68,586	22,910

PUGET SOUND ENERGY SUMMARY OF OPERATIONS (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2011	2010	2009	2008	2007
Operating revenue	$ 3,319,803	$ 3,122,217	$ 3,328,501	$ 3,357,773	$ 3,220,147
Operating income	431,043	207,591	383,135	392,386	450,384
Net income	204,120	26,095	159,252	162,736	191,127
Total assets at year end	$10,085,547	$ 9,310,784	$ 8,816,571	$ 8,435,855	$ 7,592,210
Long-term debt	3,523,845	2,953,860	2,638,860	2,270,860	2,428,860
Preferred stock subject to mandatory redemption	--	--	--	1,889	1,889
Junior subordinated notes	250,000	250,000	250,000	250,000	250,000
Capital lease obligations	32,207	--	54,196	68,586	22,910

1 *All of the operations of Puget Energy are conducted through its subsidiary PSE. "Predecessor" refers to the operations of Puget Energy and PSE prior to the consummation of the merger. "Successor" refers to the operations of Puget Energy and PSE subsequent to the merger. The merger was accounted for in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 805. For a description of this transaction, see Note 3 to the consolidated financial statements included in Item 8 of this report.*

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the financial statements and related notes thereto included elsewhere in this report on Form 10-K. The discussion contains forward-looking statements that involve risks and uncertainties, such as Puget Energy and PSE objectives, expectations and intentions. Words or phrases such as "anticipates," "believes," "continues," "could," "estimates," "expects," "future," "intends," "may," "might," "plans," "potential," "predicts," "projects," "should," "will likely result," "will continue" and similar expressions are intended to identify certain of these forward-looking statements. However, these words are not the exclusive means of identifying such statements. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. Puget Energy's and PSE's actual results could differ materially from results that may be anticipated by such forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed in the section entitled "Forward-Looking Statements" and "Risk Factors" included elsewhere in this report. Except as required by law, neither Puget Energy nor PSE undertakes an obligation to revise any forward-looking statements in order to reflect events or circumstances that may subsequently arise. Readers are urged to carefully review and consider the various disclosures made in this report and in Puget Energy's and PSE's other reports filed with the United States Securities and Exchange Commission (SEC) that attempt to advise interested parties of the risks and factors that may affect Puget Energy's and PSE's business, prospects and results of operations.

OVERVIEW

Puget Energy is an energy services holding company and all of its operations are conducted through its subsidiary PSE, a regulated electric and natural gas utility company. PSE is the largest electric and natural gas utility in the state of Washington, primarily engaged in the business of electric transmission, distribution and generation and natural gas distribution. Puget Energy's business strategy is to generate stable cash flows by offering reliable electric and natural gas service in a cost-effective manner through PSE. On February 6, 2009, Puget Holdings completed its merger with Puget Energy. Puget Holdings is a consortium of long-term infrastructure investors including Macquarie Infrastructure Partners I, Macquarie Infrastructure Partners II, Macquarie Capital Group Limited, Macquarie-FSS Infrastructure Trust, the Canada Pension Plan Investment Board (CPPIB), the British Columbia Investment Management Corporation, and the Alberta Investment Management Corporation. As a result of the merger, all of Puget Energy's common stock is indirectly owned by Puget Holdings. Puget Energy accounted for the merger as a business combination and all its assets and liabilities were recorded at fair value as of the merger date. PSE's basis of accounting continues to be on a historical basis and PSE's financial statements do not include any purchase accounting adjustments. Puget Energy and PSE are collectively referred to herein as "the Company."

PSE generates revenue and cash flow primarily from the sale of electric and natural gas services to residential and commercial customers within a service territory covering approximately 6,000 square miles, principally in the Puget Sound region of the state of Washington. To meet customer growth, to replace expiring power contracts and to meet Washington state's renewable energy portfolio standards, PSE is increasing energy efficiency programs to reduce the demand for additional energy generation and is pursuing additional renewable energy production resources (primarily wind) and base load natural gas-fired generation. The Company's external financing requirements principally reflect the cash needs of its construction program, its schedule of maturing debt and certain operational needs. PSE requires access to bank and capital markets to meet its financing needs.

For the year ended December 31, 2011 as compared to the prior year, PSE's net income was positively affected by the following four factors; (1) a decrease in net unrealized loss on derivative instruments primarily due to reversal of prior period losses that were settled during the period related to natural gas and power contracts due to declining wholesale electricity and natural gas prices which were slightly offset by losses associated with lower forward wholesale prices of natural gas and electricity; (2) an increase in electric and natural gas retail sales primarily due to cooler temperatures in 2011 as compared to warmer than normal temperatures in 2010 during the first quarter; (3) lower power costs resulting from above-average hydroelectric and wind conditions that positively impacted PSE's electric generation in 2011 as compared to higher costs resulting from below-average hydroelectric and wind conditions in 2010; and (4) an increase in Allowance for

Funds Used During Construction (AFUDC) debt and equity components due to higher construction expenditures in 2011 as compared to 2010 which are capitalized to construction projects.

NON-GAAP FINANCIAL MEASURES

The following discussion includes financial information prepared in accordance with generally accepted accounting principles (GAAP), as well as return on equity excluding unrealized loss on derivative instruments (net income plus unrealized loss on derivative instruments divided by average common equity) that is considered a "non-GAAP financial measure." This measure is a supplemental financial measure that is not prepared in accordance with GAAP. Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that exclude (or include) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. The presentation of return on equity excluding unrealized loss on derivative instruments is intended to supplement readers' understanding of the Company's operating performance. Return on equity excluding unrealized loss on derivative instrument is used by the Company to determine whether the Company is collecting the appropriate earnings from its customers to allow recovery of investor's capital. Furthermore, this measure is not intended to replace return on equity (net income divided by average common equity) as determined in accordance with GAAP as an indicator of operating performance and may not be comparable to similarly titled measures used by other companies.

The Company has faced certain challenges which caused a significant reduction in the return on equity as compared to other years. The following table presents PSE's return on equity for 2011 and 2010:

	2011			2010		
(Dollars in Thousands)	Earnings	Average Common Equity	Return On Equity	Earnings	Average Common Equity	Return On Equity
Return on equity - GAAP	$ 204,120	$3,098,564	6.6%	$ 26,095	$3,028,990	0.9%
Plus: Unrealized loss on derivative instruments, after-tax	35,195	--	*	108,519	--	*
Less: Equity adjustments [1]	--	341,231	*	--	269,484	*
Plus: Impact of average of monthly average (AMA)	--	36,242	*		(53,238)	*
AMA regulated return on equity	$ 239,315	$3,476,037	6.9%	$ 134,614	$3,245,236	4.1%
Authorized regulated return on equity [2]			10.1%			10.1%

1 *Equity adjustments related to backing out the impacts of accumulated other comprehensive income, subsidiary retained earnings and retained earnings of derivative instruments.*
2 *The authorized regulated return on equity was approved by the Washington Commission in its general rate case order which became effective April 8, 2010.*
* *Not meaningful*

The Company's 2011 return on equity, excluding derivative instruments, was 6.9%, which is lower than the authorized return on equity due to the following:

- Utility operations and maintenance expense was $21 million higher than the amount allowed in rates for the year ended December 31, 2011. The increase was driven by an increase in costs in electric production, administration and general expenses and gas operations costs.
- Depreciation expense was $30 million higher than the amount allowed in rates for the year ended December 31, 2011. The increase was primarily due to additional electric and common utility capital expenditures placed into service.
- Utility rate making process has a delay between incurring expenses and their recovery in ratebase. PSE increased ratebase by $484 million since its last general rate increase effective April 8, 2010. On June 13, 2011, PSE filed a general rate increase for electric and gas with the Washington Commission.
- These negative impacts were offset by favorable load which increased natural gas therm sales 7.0% for the year ended December 31, 2011, due to cooler temperatures in the current year as compared

to the same period in prior year. Also, favorable electric power costs had a positive impact on net income.

The Company's 2010 return on equity, excluding derivative instruments, was 4.1%, which is lower than the authorized return on equity due to the following:

- Electric retail kilowatt sales and natural gas therm sales for the year ended December 31, 2010 declined 2.3% and 1.9%, respectively, as compared to historical averages due to warmer temperatures in the first quarter of 2010 which was one of its highest revenue quarters for the year and, to a lesser extent, the impact of PSE's residential and commercial customer conservation programs, as well as continued effects of weak economic conditions in the Pacific Northwest.
- The Pacific Northwest experienced below normal hydrological and wind conditions which adversely impacted PSE's power costs in the first quarter of 2010. Hydroelectric and wind generation for the year ended December 31, 2010 decreased by 700,511 MWhs, or 11.8%, as compared to historical averages. As a result, PSE's power costs in excess of the baseline rate was $29.2 million due to purchasing or generating higher cost electricity to replace the decrease in generation from hydroelectric and wind generating projects.
- PSE had requested electric and natural gas rate increases of $110.3 million and $27.2 million, respectively in 2009. The Washington Commission approved general rate case increases of $74.1 million and $18.3 million for electric and natural gas customers, respectively which were effective April 8, 2010. The difference between the allowed and requested increases included a rate of return with a lower equity return and lower equity component than requested, in addition to stricter interpretation of proforma adjustments from what was previously allowed.
- As a result of the Washington Commission order of May 20, 2010, PSE adjusted the carrying value of its California wholesale energy sales regulatory asset in the second quarter of 2010 by $17.8 million pre-tax (from $21.1 million to $3.3 million), which impacted wholesale energy sales.

Factors and Trends Affecting PSE's Performance. PSE's regulatory requirements and operational needs require the investment of substantial capital in 2012 and future years. Because PSE intends to seek recovery of such investments through the regulatory process, its financial results depend heavily upon favorable outcomes from that process. Further, PSE's financial performance is heavily influenced by general economic conditions in its service territory, which affect customer growth and use-per-customer and thus utility sales, as well as by its customers' conservation investments, which also tend to reduce energy sales. The principal business, economic and other factors that affect PSE's operations and financial performance include:

- The rates PSE is allowed to charge for its services;
- PSE's ability to recover fixed costs that are included in rates which are based on volume;
- Weather conditions, including snow-pack affecting hydrological conditions;
- Demand for electricity and natural gas among customers in PSE's service territory;
- Regulatory decisions allowing PSE to recover costs, including purchased power and fuel costs, on a timely basis;
- PSE's ability to supply electricity and natural gas, either through company-owned generation, power purchase contracts or by procuring natural gas or electricity in wholesale markets;
- Availability and access to capital and the cost of capital;
- Regulatory compliance costs, including those related to new and developing federal regulations of electric system reliability, state regulations of natural gas pipelines and federal, state and local environmental laws and regulations;
- The impact of energy efficiency programs on sales and margins;
- Wholesale commodity prices of electricity and natural gas;
- Increasing depreciation and related property taxes; and
- Federal, state, and local taxes.

Regulation of PSE Rates and Recovery of PSE Costs. The rates that PSE is allowed to charge for its services influence its financial condition, results of operations and liquidity. PSE is highly regulated and the rates that it charges its retail customers are approved by the Washington Commission. The Washington Commission requires these rates be determined based, to a large extent, on historic test year costs plus weather normalized assumptions about hydroelectric conditions and power costs in the relevant rate year. Incremental customer growth and sales typically do not provide sufficient revenue to cover year-to-year cost growth, thus rate increases are required. If, in a particular year, PSE's costs are higher than what is allowed to be recovered in rates, revenue may not be sufficient to permit PSE to earn its allowed return. In addition, the Washington Commission determines whether expenses and investments are reasonable and prudent in providing electric and natural gas service. If the Washington Commission determines that part of PSE's costs do not meet the standard applied, those costs may be disallowed partially or entirely and not recovered in rates.

ELECTRIC RATES

PSE has a PCA mechanism that provides for the recovery of power costs from customers or refunding of power cost savings to customers in the event those costs vary from the "power cost baseline" level of power costs. The "power cost baseline" levels are set, in part, based on normalized assumptions about weather and hydroelectric conditions. Excess power costs or power cost savings are apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism.

The graduated scale is as follows:

ANNUAL POWER COST VARIABILITY	CUSTOMERS' SHARE	COMPANY'S SHARE
+/- $20 million	0%	100%
+/- $20 million - $40 million	50%	50%
+/- $40 million - $120 million	90%	10%
+/- $120 + million	95%	5%

PSE had a favorable PCA imbalance for the year ended December 31, 2011, which was $38.1 million below the "power cost baseline" level, $9.0 million of which was apportioned to customers. This compares to an unfavorable imbalance of $31.3 million for the year ended December 31, 2010, $7.2 million of which was apportioned to customers.

On June 13, 2011, PSE filed a general rate increase with the Washington Commission which proposed an increase in electric rates of $160.7 million or 8.1%, to be effective May 2012. PSE requested a weighted cost of capital of 8.42%, or 7.29% after-tax, and a capital structure of 48.0% in common equity with a return on equity of 10.8%. The filing also proposes a conservation savings adjustment mechanism related to energy efficiency services for business and residential customers. On September 1, 2011, PSE filed supplemental testimony to adjust the electric rate increase to $152.3 million, a 7.7% increase, due to changes in projected power costs. On January 17, 2012, PSE filed rebuttal testimony which included a reduction to the requested electric rate increase to $126.0 million. The $26.3 million reduction was primarily due to updates to power costs and to a change to the weighted cost of capital to 8.26%, or 7.17% after-tax, which included a change to the return on equity to 10.75%. Hearings related to this matter were held on February 14 through 17, 2012.

The following table sets forth electric rate adjustments approved by the Washington Commission and the corresponding impact on PSE's annual revenue based on the effective dates:

TYPE OF RATE ADJUSTMENT	EFFECTIVE DATE	AVERAGE PERCENTAGE INCREASE (DECREASE) IN RATES	ANNUAL INCREASE (DECREASE) IN REVENUE (DOLLARS IN MILLIONS)
Renewable Energy Credit Proceeds	November 1, 2010 – March 31, 2011	(2.9)%	$ (27.7)
Electric General Rate Case	April 8, 2010, Annual	3.7%	74.1

NATURAL GAS RATES

On March 14, 2011, the Washington Commission issued its order authorizing PSE to increase its natural gas general tariff rates by $19.0 million or 1.8% on an annual basis effective April 1, 2011.

On April 26, 2011, PSE filed a new tariff for a Natural Gas Pipeline Integrity Program. This program is intended to enhance pipeline safety by providing for the timely recovery of the Company's cost to replace certain natural gas system infrastructure that would emphasize system reliability, integrity and safety which would increase natural gas revenue by $1.9 million or 0.2%. The Washington Commission held a hearing on November 17, 2011 and a Commission Order is the next awaited step in the proceeding.

On June 13, 2011, PSE filed a general rate increase with the Washington Commission which proposed an increase in natural gas rates of $31.9 million or 3.0%, to be effective May 2012. PSE requested a weighted cost of capital of 8.42%, or 7.29% after-tax, and a capital structure of 48.0% in common equity with a return on equity of 10.8%. The filing also proposes a conservation savings adjustment mechanism related to energy efficiency services for business and residential customers. On January 17, 2012, PSE filed rebuttal testimony which included a reduction to the requested natural gas rate increase to $28.6 million. The $3.3 million reduction was primarily due to a change to the weighted cost of capital to 8.26%, or 7.17% after-tax, which included a change to the return on equity to 10.75%. Hearings related to this matter were held on February 14 through 17, 2012.

On October 27, 2011, the Washington Commission approved PSE's PGA natural gas tariff filing effective November 1, 2011, to decrease the rates charged to customers under the PGA. The estimated revenue impact of the approved charge is a decrease of $43.5 million, or 4.3% annually. The rate adjustment has no impact on PSE's net income.

PSE has a PGA mechanism in retail natural gas rates to recover variations in natural gas supply and transportation costs. Variations in natural gas rates are passed through to customers; therefore, PSE's net income is not affected by such variations. Changes in the PGA rates affect PSE's revenue, but do not impact net income as the changes to revenue are offset by increased or decreased purchased gas and gas transportation costs.

The following table sets forth natural gas rate adjustments that were approved by the Washington Commission and the corresponding impact to PSE's annual revenue based on the effective dates:

Type of Rate Adjustment	Effective Date	Average Percentage Increase (Decrease) in Rates	Annual Increase (Decrease) in Revenue (Dollars in Millions)
Purchased Gas Adjustment	November 1, 2011	(4.3)%	$ (43.5)
Natural Gas General Tariff Adjustment	April 1, 2011	1.8	19.0
Purchased Gas Adjustment	November 1, 2010 – October 31, 2011	1.9	18.3
Natural Gas General Rate Case	April 8, 2010	0.8	10.1
Purchased Gas Adjustment	October 1, 2009 – October 31, 2010	(17.1)	(198.1)
Purchased Gas Adjustment	June 1, 2009 – May 31, 2010	(1.8)	(21.2)
Purchased Gas Adjustment	October 1, 2008 – September 30, 2009	11.1	108.8

Weather Conditions. Weather conditions in PSE's service territory have a significant impact on customer energy usage, affecting PSE's revenue and energy supply expenses. PSE's operating revenue and associated energy supply expenses are not generated evenly throughout the year. While both PSE's electric and natural gas sales are generally greatest during winter months, variations in energy usage by customers occur from season to season and month to month within a season, primarily as a result of weather conditions. PSE normally experiences its highest retail energy sales, and subsequently higher power costs, during the winter heating season in the first and fourth quarters of the year and its lowest sales in the third quarter of the year. Varying wholesale electric prices and the amount of hydroelectric energy supplies available to PSE also make quarter-to-quarter comparisons difficult. PSE reported higher customer usage in the year ended December 31, 2011 primarily due to Pacific Northwest temperatures being 1.54 degrees cooler, as compared to the same period in 2010, which translates to a 13.1% increase in heating degree days.

Customer Demand. PSE expects the number of natural gas customers to grow at rates slightly above electric customers. PSE also expects energy usage by both residential electric and natural gas customers to continue a long-term trend of slow decline due to continued energy efficiency improvements and the effect of higher retail rates. The effects of the current recession on Washington's economy have exacerbated a decline in customer usage throughout 2011.

Access to Debt Capital. PSE relies on access to bank borrowings and short-term money markets as sources of liquidity and longer-term debt markets to fund its utility construction program, to meet maturing debt obligations and other capital expenditure requirements not satisfied by cash flow from its operations or equity investment from its parent, Puget Energy. Neither Puget Energy nor PSE have any debt outstanding whose maturity would accelerate upon a credit rating downgrade.

However, a ratings downgrade could adversely affect the Company's ability to renew existing, or obtain access to new credit facilities and could increase the cost of such facilities. For example, under Puget Energy's and PSE's credit facilities, the borrowing costs and commitment fees increase as their respective credit ratings decline. If PSE is unable to access debt capital on reasonable terms, its ability to pursue improvements or acquisitions, including generating capacity, which may be relied on for future growth and to otherwise implement its strategy, could be adversely affected. PSE monitors the credit environment and expects to continue to be able to access the capital markets to meet its short-term and long-term borrowing needs. PSE's credit facilities expire in 2014 and Puget Energy's credit facility expires in 2017. (See discussion on credit facilities in "Financing Program" section.)

Regulatory Compliance Costs and Expenditures. PSE's operations are subject to extensive federal, state and local laws and regulations. Such regulations cover electric system reliability, gas pipeline system safety and energy market transparency, among other areas. Environmental laws and regulations related to air and water quality (including climate change) and endangered species protection, waste handling and disposal (including generation byproducts such as coal ash), remediation of contamination and siting new facilities also impact the Company's operations. PSE must spend significant amounts fulfilling requirements by regulatory agencies, many of which have greatly expanded mandates, and on measures including, but not limited to, resource planning, remediation, monitoring, pollution control equipment and emissions-related abatement and fees in order to comply with these regulatory requirements.

Compliance with these or other future regulations, such as those pertaining to climate change and generation byproducts could require significant capital expenditures by PSE and may adversely affect PSE's financial position, results of operations, cash flows and liquidity.

OTHER CHALLENGES AND STRATEGIES

Energy Supply. As noted in PSE's IRP filed with the Washington Commission, PSE projects future energy needs will exceed current resources from long-term power purchase agreements and Company-controlled power resources. The IRP identifies reductions in contractual supplies of energy and capacity available under certain long-term power purchase agreements, requiring replacement of supplies to meet projected demands. Therefore, PSE's IRP sets forth a multi-part strategy of implementing energy efficiency programs and pursuing additional renewable resources (primarily wind) and additional base load natural gas-fired generation to meet the growing needs of its customers. If PSE cannot acquire needed energy supply resources at a reasonable cost, it may be required to purchase additional power in the open market at a cost that could, in the absence of regulatory relief, significantly increase its expenses and reduce earnings and cash flows.

Infrastructure Investment. PSE is investing in its utility infrastructure and customer service functions in order to meet regulatory requirements, serve customers' energy needs and replace aging infrastructure. These investments and operating requirements give rise to significant growth in depreciation, amortization and operating expenses, which are not recovered through the ratemaking process in a timely manner. This "regulatory lag" is expected to continue for the foreseeable future.

Operational Risks Associated With Generating Facilities. PSE owns and operates coal, natural gas-fired, hydroelectric, wind-powered and oil-fired generating facilities. Operation of electric generating facilities involves risks that can adversely affect energy output and efficiency levels, including facility shutdowns due to equipment and process failures or fuel supply interruptions. PSE does not have business interruption insurance coverage to cover replacement power costs.

Energy Efficiency Related Lost Sales Margin. PSE's sales, margins, earnings and cash flow are adversely affected by its energy efficiency programs, many of which are mandated by law. The Company is evaluating strategies and other means to reduce or eliminate these adverse financial effects. In 2011, as part of the general rate case, a conservation adjustment was proposed to help recover lost margins.

Markets For Intangible Power Attributes. The Company is actively engaged in monitoring the development of the commercial markets for such intangible power attributes as RECs and carbon financial instruments. The Company supports the development of regional and national markets for such products that are free, open, transparent and liquid.

RESULTS OF OPERATIONS

Puget Sound Energy

The following discussion should be read in conjunction with the audited consolidated financial statements and the related notes included elsewhere in this document. The following discussion provides the significant items that impacted PSE's results of operations for the years ended December 31, 2011 and 2010. Set forth below is the consolidated financial results of PSE for the years ended December 31, 2011, 2010 and 2009:

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2011	 2010	FAVORABLE/ (UNFAVORABLE)	YEAR ENDED DECEMBER 31, 2009	FAVORABLE/ (UNFAVORABLE)
Operating revenue:					
Electric					
Residential sales	$ 1,144,165	$ 1,078,262	6.1%	$ 1,067,274	1.0 %
Commercial sales	853,880	836,957	2.0	838,275	(0.2)
Industrial sales	108,247	103,678	4.4	99,552	4.1
Other retail sales, including unbilled revenue	17,651	12,787	38.0	16,424	(22.1)
Total retail sales	2,123,943	2,031,684	4.5	2,021,525	0.5
Transportation sales	10,275	11,000	(6.6)	10,623	3.5
Sales to other utilities and marketers	45,726	62,943	(27.4)	78,471	(19.8)
Other	(32,724)	1,842	*	(11,883)	115.5
Total electric operating revenue	2,147,220	2,107,469	1.9	2,098,736	0.4
Gas					
Residential sales	760,441	648,649	17.2	795,756	(18.5)
Commercial sales	344,326	301,083	14.4	357,110	(15.7)
Industrial sales	34,867	33,004	5.6	39,531	(16.5)
Total retail sales	1,139,634	982,736	16.0	1,192,397	(17.6)
Transportation sales	15,017	14,082	6.6	13,014	8.2
Other	14,199	14,713	(3.5)	19,334	(23.9)
Total gas operating revenue	1,168,850	1,011,531	15.6	1,224,745	(17.4)
Non-utility operating revenue	3,733	3,217	16.0	5,020	(35.9)
Total operating revenue	3,319,803	3,122,217	6.3	3,328,501	(6.2)
Operating expenses:					
Energy costs:					
Purchased electricity	771,983	774,007	0.3	887,306	12.8
Electric generation fuel	199,471	268,147	25.6	208,444	(28.6)
Residential exchange	(71,147)	(75,109)	(5.3)	(96,504)	(22.2)
Purchased gas	622,088	535,933	(16.1)	718,860	25.4
Net unrealized (gain) loss on derivative instruments	54,146	166,953	67.6	(1,254)	*
Utility operations and maintenance	497,921	486,701	(2.3)	487,396	0.1
Non-utility expense and other	11,147	11,159	0.1	14,532	23.2
Merger and related costs	--	--	*	23,908	*
Depreciation	299,597	292,634	(2.4)	269,386	(8.6)
Amortization	72,381	71,572	(1.1)	63,466	(12.8)
Conservation amortization	107,646	90,109	(19.5)	66,466	(35.6)
Taxes other than income taxes	323,527	292,520	(10.6)	303,360	3.6
Total operating expenses	2,888,760	2,914,626	0.9	2,945,366	1.0
Operating income	431,043	207,591	107.6	383,135	(45.8)
Other income	58,041	45,153	28.5	52,812	(14.5)
Other expense	(5,380)	(5,673)	5.2	(6,524)	13.0
Interest expense	(201,467)	(220,854)	8.8	(202,527)	(9.0)
Income before income taxes	282,237	26,217	*	226,896	(88.4)
Income tax expense	78,117	122	*	67,644	99.8
Net income	$ 204,120	$ 26,095	*%	$ 159,252	(83.6)%

* *Not meaningful*

NON-GAAP FINANCIAL MEASURES – ELECTRIC AND GAS MARGINS

The following discussion includes financial information prepared in accordance with U.S. Generally Accepted Accounting Principles (GAAP), as well as two other financial measures, electric margin and gas margin, that are considered "non-GAAP financial measures." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that exclude (or include) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. The presentation of electric margin and gas margin is intended to supplement an understanding of PSE's operating performance. Electric margin and gas margin are used by PSE to determine whether PSE is collecting the appropriate amount of energy costs from its customers to allow recovery of operating costs. PSE's electric margin and gas margin measures may not be comparable to other companies' electric margin and gas margin measures. Furthermore, these measures are not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

ELECTRIC MARGIN

The following table displays the details of PSE's electric margin changes from periods 2010 to 2011 and periods 2009 to 2010. Electric margin represents electric sales to retail and transportation customers less pass-through tariff items, revenue-sensitive taxes and the cost of generating and purchasing electric energy sold to customers, including transmission costs to bring electric energy to PSE's service territory.

ELECTRIC MARGIN (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2011	2010	PERCENT CHANGE	YEAR ENDED DECEMBER 31, 2009	PERCENT CHANGE
Electric operating revenue[1]	$2,147,220	$2,107,469	1.9%	$2,098,736	0.4%
Add (less): Other electric operating revenue	32,723	(1,841)	*	11,883	*
Less: Other electric operating revenue-gas supply resale	(58,402)	(36,748)	58.9	(46,626)	(21.2)
Add (less): Other electric operating revenue-RECs & PTCs	(15,344)	3,231	*	--	*
Total electric revenue for margin	2,106,197	2,072,111	1.6	2,063,993	0.4
Adjustments for amounts included in revenue:					
Pass-through tariff items	(101,864)	(90,071)	(13.1)	(69,839)	(29.0)
Pass-through revenue-sensitive taxes	(158,661)	(150,565)	(5.4)	(150,119)	(0.3)
Net electric revenue for margin	1,845,672	1,831,475	0.8	1,844,035	(0.7)
Minus power costs:					
Purchased electricity[1]	(771,983)	(774,007)	0.3	(887,306)	12.8
Electric generation fuel[1]	(199,471)	(268,147)	25.6	(208,444)	(28.6)
Residential exchange[1]	71,147	75,109	5.3	96,504	22.2
Total electric power costs	(900,307)	(967,045)	6.9	(999,246)	3.2
Electric margin[2]	$ 945,365	$ 864,430	9.4%	$ 844,789	2.3%

1 *As reported on PSE's Consolidated Statement of Income.*

2 *Electric margin does not include any allocation for amortization/depreciation expense or electric generation operation and maintenance expense.*

* *Percent change not applicable or meaningful.*

Electric margin increased $80.9 million and $19.6 million for the years ended December 31, 2011 and December 31, 2010, respectively. Following is a discussion of significant items that impact electric operating revenue and electric energy costs which are included in electric margin:

2011 COMPARED TO 2010

ELECTRIC OPERATING REVENUE

Electric operating revenue increased $39.8 million, or 1.9%, to $2,147.2 million from $2,107.5 million for the year ended December 31, 2011 as compared to the same period in 2010. The increase in operating revenue of $39.8 million was due to higher electric retail sales of $92.3 million offset by lower sales to other utilities and marketers of $17.2 million and by lower miscellaneous operating revenue of $34.6 million. These items are discussed in detail below.

Electric retail sales. Electric retail sales increased $92.3 million, or 4.5%, to $2,123.9 million from $2,031.7 million for the year ended December 31, 2011 as compared to the same period in 2010. The increase in electric retail sales was due to a $57.7 million increase in retail electricity usage of 595,487 MWhs, or 2.8%, primarily due to cooler temperatures in PSE's service territory during the year ended December 31, 2011 as compared to the same period in the prior year. The average temperature during the year ended December 31, 2011 was 50.7 degrees, or 1.54 degrees colder than the same period in the prior year, which resulted in a 13.1% increase in heating degree days. Additionally, the electric rate increase effective April 8, 2010 contributed $25.9 million to the increase in electric retail sales. Also contributing to the increase in retail sales were pass-through items with no impact to earnings including a $11.5 million increase in conservation rider program rates, a $7.7 million decrease related to the suspension of the PTC tariff credit effective July 1, 2010, a $4.1 million decrease in the residential exchange rate credit and various other pass-through items. PTCs that are generated and provided to customers are recorded as a reduction in other electric operating revenue until PSE utilizes the tax credit on its tax return, at which time the PTCs will be credited to customers in retail sales. Additionally, PSE's customers were credited $10.5 million for REC revenue, effective November 1, 2010, resulting in a decrease in electric retail sales. The $10.5 million credit to customers is offset in other electric operating revenue with no impact to earnings. PSE's customers continued to receive credits through April 30, 2011.

Sales to other utilities and marketers. Sales to other utilities and marketers decreased $17.2 million for the year ended December 31, 2011 as compared to the same period in 2010. The decrease was primarily due to a reduction in sales volumes of 687,124 MWhs, or 27.5% which decreased revenue $22.2 million and a decline in wholesale electricity prices which decreased revenue by $12.8 million. Additionally, in the prior year there was a carrying value adjustment of $17.8 million related to PSE's California wholesale energy sales regulatory asset that did not occur in 2011.

Other electric operating revenue. Other electric operating revenue decreased $34.6 million for the year ended December 31, 2011 as compared to the same period in 2010. For the year ended December 31, 2011, the decrease was primarily due to a decrease in non-core gas sales of $21.7 million and a decrease of $85.5 related to PTCs, partially offset by an increase in REC revenue of $67.0 million, PTCs are deferred until PSE utilizes the tax credit on its tax return. As discussed above, REC revenue is an offset of the REC credit provided to PSE's customers in electric retail sales with no impact to earnings.

ELECTRIC ENERGY COSTS

Purchased electricity expense decreased $2.0 million, or 0.3%, for the year ended December 31, 2011 as compared to the same period in 2010. The decrease in purchased electricity expense for the year ended December 31, 2011 was primarily the result of lower wholesale market prices, which contributed $180.6 million to the decrease. This decrease was offset by an increase in purchased power of 3,217,631 MWhs, or 23.2%, resulting in an increase of $160.3 million, which was driven by cooler temperatures during the year ended December 31, 2011 as compared to the same period in the prior year. In addition the decrease was offset by an overrecovery of power costs from customers of $9.0 million for the year ended December 31, 2011, which reduced the customer PCA deferral as compared to an underrecovery of power costs of $7.2 million in the same period in 2010. The overrecovery of power costs was due to above-average hydroelectric and wind generation resulting in decreased power costs associated with purchased electricity and fuel costs of PSE's combustion turbines.

To meet customer demand, PSE economically dispatches resources in its power supply portfolio such as fossil-fuel generation, owned and contracted hydroelectric capacity and energy and long-term contracted power. However, depending principally upon availability of hydroelectric energy, plant availability, fuel prices and/or changing load as a result of weather, PSE may sell surplus power or purchase deficit power in the wholesale market. PSE manages its regulated power portfolio through short-term and intermediate-term off-system physical purchases and sales as well as through other risk management techniques.

Electric generation fuel expense decreased $68.7 million, or 25.6%, for the year ended December 31, 2011 as compared to the same period in 2010. The decrease was primarily due to lower volumes of electricity generation from PSE's combustion turbine facilities as a result of increases in hydroelectric and wind generation of 1,219,910 MWhs, or 19.2%. Also, coal generation at Colstrip decreased 987,522 MWhs, or 19.0% for the year ended December 31, 2011 as compared to the same period in 2010. Generation fuel costs were also lower, due to low wholesale market prices, as it was more economical to purchase wholesale energy than to generate energy from PSE's combustion turbine facilities.

Residential exchange credits decreased $4.0 million, or 5.3%, for the year ended December 31, 2011 as compared to the same period in 2010 as a result of lower electric residential and farm customer sales volumes associated with the BPA

Residential Exchange Program (REP). The REP credit is a pass-through tariff item with a corresponding credit in electric operating revenue, with no impact on net income.

2010 COMPARED TO 2009

ELECTRIC OPERATING REVENUE

Electric operating revenue increased $8.8 million, or 0.4%, to $2,107.5 million from $2,098.7 million for the year ended December 31, 2010 as compared to the same period in 2009. The increase in operating revenue of $8.8 million was due to higher electric retail sales of $10.1 million and higher miscellaneous operating revenue of $13.7 million. These increases were offset by lower sales to other utilities and marketers of $15.5 million. These items are discussed in detail below.

Electric retail sales. Electric retail sales increased $10.2 million, or 0.5%, to $2,031.7 million from $2,021.5 million for the year ended December 31, 2010 as compared to the same period in 2009. The increase in electric retail sales was due to a $47.9 million electric rate increase effective April 8, 2010. Partially offsetting the increase in electric retail sales was an $88.8 million decline in retail electricity usage of 965,695 MWhs, or 4.4%, primarily due to warmer than average temperatures in the Pacific Northwest during the first quarter of 2010 as compared to the same period in 2009. The average temperature during the first quarter of 2010 was 46.8 degrees, or 6.2 degrees warmer than the same period in 2009. As a result of the warmer first quarter of 2010, heating degree days for the year ended December 31, 2010 were 7.1% lower than the same period in 2009. The decline in retail electricity usage was also due to an increase in PSE's residential and commercial customer conservation programs and the continued effects of a weak Pacific Northwest economy. Also contributing to the increase in retail sales are pass-through items with no impact to earnings including a $22.3 million increase attributable to a decrease in benefits (credits to customers) of the Residential and Small Farm Energy Exchange Benefit, a $20.2 million increase due to conservation rider program rate increases and a $17.0 million increase in retail sales related to the suspension of the PTC tariff effective July 1, 2010. PTCs that are generated and provided to customers are recorded as a reduction in other electric operating revenue until PSE utilizes the tax credit on its tax return at which time the PTCs will be credited to customers in retail sales. Additionally, PSE's customers were credited $10.5 million for REC revenue effective November 1, 2010, resulting in a decrease in electric retail sales. The $10.5 million credit to customers is offset in other electric operating revenue with no impact to earnings. PSE's customers will continue to receive credits through March 2011.

Sales to other utilities and marketers. Sales to other utilities and marketers decreased $15.5 million, or 19.8% for the year ended December 31, 2010 as compared to the same period in 2009. This decrease was primarily due to a carrying value adjustment of $17.8 million related to PSE's California wholesale energy sales regulatory asset and a reduction in sales volumes of 28,981 MWhs, or 1.1% which decreased revenue by $1.0 million. Partially offsetting the decline was an increase in wholesale electricity prices which increased by $3.1 million.

Other electric operating revenue. Other operating revenue increased $13.7 million for the year ended December 31, 2010 as compared to the same period in 2009. The increase was primarily due to an increase in non-core gas sales of $9.9 million and REC revenue of $10.5 million. As discussed above, REC revenue is an offset of the REC credit provided to PSE's customers in electric retail sales with no impact to earnings. Partially offsetting the increase to other operating revenue was $7.3 million of PTCs which are deferred until PSE utilizes tax credit on its tax return.

ELECTRIC ENERGY COSTS

Purchased electricity expense decreased $113.3 million, or 12.8%, for the year ended December 31, 2010 as compared to the same period in 2009. The decrease was primarily the result of a decrease in purchased power of 1,349,571 MWhs, or 8.9%, resulting in a decrease of $71.6 million and by lower wholesale market prices which contributed $44.5 million. The decrease in purchased power for the year ended December 31, 2010 was primarily the result of lower customer usage related to warmer than normal temperatures during 2010, a weak economy in the Pacific Northwest and 18.7% higher generation of electricity from PSE's coal-fired generation facility, Colstrip, due to Colstrip Unit 4 having an extended outage in 2009.

To meet customer demand, PSE economically dispatches resources in its power supply portfolio such as fossil-fuel generation, owned and contracted hydroelectric capacity and energy and long-term contracted power. However, depending principally upon availability of hydroelectric energy, plant availability, fuel prices and/or changing load as a result of weather, PSE may sell surplus power or purchase deficit power in the wholesale market. PSE manages its regulated power portfolio through short-term and intermediate-term off-system physical purchases and sales as well as through other risk management techniques.

Electric generation fuel expense increased $59.7 million, or 28.6%, for the year ended December 31, 2010 as compared to the same period in 2009. The increase was primarily due to a $44.5 million increase in costs at PSE's combustion turbine facilities and a $15.2 million increase related to increased generation at Colstrip in 2010 due to the Colstrip Unit 4 extended outage in 2009. Also contributing to the increased electric generation fuel expense at company-owned natural gas facilities was an 8.0% decrease in hydroelectric generation by Company-owned facilities and under take-or-pay purchased electricity contracts partially offset by an increase in wind generation.

Residential exchange credits decreased $21.4 million, or 22.2%, for the year ended December 31, 2010 as compared to the same period in 2009 as a result of lower electric residential and farm customer sales volumes associated with the BPA REP. The REP credit is a pass-through tariff item with a corresponding credit in electric operating revenue, with no impact on net income.

NATURAL GAS MARGIN

The following table displays the details of PSE's natural gas margin changes from 2010 to 2011 and 2009 to 2010. Gas margin is natural gas sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes and the cost of natural gas purchased, including transportation costs to bring natural gas to PSE's service territory.

NATURAL GAS MARGIN (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2011	2010	PERCENT CHANGE	YEAR ENDED DECEMBER 31, 2009	PERCENT CHANGE
Gas operating revenue[1]	$1,168,850	$1,011,531	15.6%	$1,224,745	(17.4)%
Less: Other gas operating revenue	(14,198)	(14,713)	(3.5)	(19,334)	(23.9)
Total gas revenue for margin	1,154,652	996,818	15.8	1,205,411	(17.3)
Adjustments for amounts included in revenue:					
Pass-through tariff items	(26,441)	(18,927)	39.7	(14,441)	31.1
Pass-through revenue-sensitive taxes	(93,809)	(80,554)	16.5	(97,736)	(17.6)
Net gas revenue for margin	1,034,402	897,337	15.3	1,093,234	(17.9)
Minus purchased gas costs[1]	(622,088)	(535,933)	16.1	(718,860)	(25.4)
Natural gas margin[2]	$ 412,314	$ 361,404	14.1%	$ 374,374	(3.5)%

1 *As reported on PSE's Consolidated Statement of Income.*

2 *Gas margin does not include any allocation for amortization/depreciation expense or electric generation operations and maintenance expense.*

Gas margin increased $50.9 million and decreased $13.0 million for the years ended December 31, 2011 and December 31, 2010, respectively. Following is a discussion of significant items that impact gas operating revenue and gas energy costs which are included in natural gas margin:

2011 COMPARED TO 2010

GAS OPERATING REVENUE

Gas operating revenue increased $157.3 million, or 15.6%, to $1,168.9 million from $1,011.5 million for the year ended December 31, 2011 as compared to the same period in 2010. The increase in gas operating revenue of $157.3 million was due primarily to higher natural gas retail sales of $156.9 million.

Natural gas retail sales. Natural gas retail sales increased $156.9 million, or 16.0%, to $1,139.6 million from $982.7 million for the year ended December 31, 2011 as compared to the same period in 2010. The increase consists of $132.6 million due to an increase in gas therms of 131.3 million, or 12.5% as a result of cooler temperatures. Also contributing is an increase of $42.5 million due to a 1.8% increase in natural gas general rate effective April 8, 2010 and a 0.8% PGA rate increase effective November 1, 2010. The increase was offset $10.9 million due to a 4.3% PGA rate decrease effective November 1, 2011. The PGA mechanism passes through to customers increases or decreases in the natural gas supply portion of the natural gas service rates based upon changes in the price of natural gas purchased from producers and wholesale marketers or changes in natural gas pipeline transportation costs. PSE's net income is not affected by changes under the PGA mechanism.

GAS ENERGY COSTS

Purchased gas expense increased $86.2 million, or 16.1%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase was primarily due to higher natural gas costs reflected in PGA rates effective November 1, 2010. In addition, an increase in customer usage of 12.5% for the year ended December 31, 2011 as compared to the same period in 2010 contributed to the increase of costs. The PGA mechanism provides the rates used to determine natural gas costs based on customer usage. The rate increase was the result of increasing costs of wholesale natural gas. The PGA mechanism allows PSE to recover expected natural gas supply and transportation costs and defer, as a receivable or liability, any natural gas supply and transportation costs that exceed or fall short of this expected natural gas cost amount in PGA mechanism rates, including accrued interest. The PGA mechanism payable balance at December 31, 2011 was $25.9 million as compared to a receivable balance of $6.0 million at December 31, 2010. PSE is authorized by the Washington Commission to accrue carrying costs on PGA receivable and payable balances. A receivable balance in the PGA mechanism reflects an underrecovery of market natural gas cost through rates. A payable balance reflects overrecovery of market natural gas cost through rates.

2010 COMPARED TO 2009

GAS OPERATING REVENUE

Gas operating revenue decreased $213.2 million, or 17.4%, to $1,011.5 million from $1,224.8 million for the year ended December 31, 2010 as compared to the same period in 2009. The decrease in gas operating revenue of $213.2 million was due primarily to lower natural gas retail sales of $209.7 million.

Natural gas retail sales. Natural gas retail sales decreased $209.7 million, or 17.6%, to $982.7 million from $1,192.4 million during year ended December 31, 2010 as compared to the same period in 2009. This decrease was primarily due to a $115.4 million decrease in gas operating revenue as a result of PGA rate decreases effective June 1, 2009 and October 1, 2009. The PGA mechanism passes through to customer increases or decreases in the natural gas supply portion of the natural gas service rates based upon changes in the price of natural gas purchased from producers and wholesale marketers or changes in natural gas pipeline transportation costs. PSE's net income is not affected by changes under the PGA mechanism. The decrease in natural gas retail sales was also due to a decrease of 87.6 million in natural gas therm sales, or 7.7%, which decreased revenue by $107.2 million. The decrease was due primarily to warmer than average temperatures in the Pacific Northwest during the first quarter of 2010 as compared to 2009, an increase in PSE's residential and commercial customer conservation programs and the continued effects of a weak Pacific Northwest economy.

GAS ENERGY COSTS

Purchased gas expense decreased $182.9 million, or 25.4%, for the year ended December 31, 2010 as compared to the same period in 2009. The decrease was due to a 7.7% decrease in customer usage and natural gas costs reflected in PGA rates. The decrease in customer usage was mainly due to a 7.1% decrease in heating degrees days during 2010 as compared to the same period in 2009, the impact of PSE's residential and commercial customer conservation programs and the continued effects of a weak Pacific Northwest economy. The PGA mechanism provides the rates used to determine natural gas costs based on customer usage. The rate decrease was the result of declining costs of wholesale natural gas. The PGA mechanism allows PSE to recover expected natural gas supply and transportation costs and defer, as a receivable or liability, any natural gas supply and transportation costs that exceed or fall short of this expected natural gas cost amount in PGA mechanism rates, including accrued interest. The PGA mechanism receivable balance at December 31, 2010 was $6.0 million as compared to payable balance of $49.6 million at December 31, 2009. PSE is authorized by the Washington Commission to accrue carrying costs on PGA receivable and payable balances. A receivable balance in the PGA mechanism reflects an underrecovery of market natural gas cost through rates. A payable balance reflects overrecovery of market natural gas cost through rates.

2011 COMPARED TO 2010

OTHER OPERATING EXPENSES

Net unrealized (gain) loss on derivative instruments decreased by $112.8 million to a loss of $54.1 million in 2011 as compared to a loss of $166.9 million during the same period in 2010. In 2011, the derivative portfolio experienced a significant number of 2010 contracts settling. As those contracts settled, the previous losses recorded in 2010 were reversed resulting in reduced losses between years. On July 1, 2009, PSE elected to de-designate its energy related derivative contracts previously designated as cash flow hedges. The de-designated contracts were physical electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and for contracts initiated after such date, all mark-to-market accounting impacts are recognized through earnings. The amount previously recorded in accumulated other comprehensive income (OCI) is transferred to earnings when the contracts settle or sooner, if management determines that the forecasted transaction is probable of not occurring. As a result, PSE will continue to experience the earnings impact of these reversals from OCI in future periods. Over the tenor of PSE's outstanding derivative contracts, the forward wholesale prices of electricity and natural gas declined 25.7% and 23.0%, respectively, from December 31, 2010 to December 31, 2011.

Utility operations and maintenance expense increased $11.2 million, or 2.3%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase was driven by increases of $11.9 million increase in electric production, $6.2 in administration and general expenses and $1.5 million in gas operations costs. Partially offsetting the increase is a $7.3 million decrease in electric transmission and distribution and a $1.7 million decrease in customer service expenses.

Depreciation expense increased $7.0 million, or 2.4%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase was primarily due to additional electrical and common utility capital expenditures placed into service, net of retirements.

Conservation amortization increased $17.5 million, or 19.5%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase was due to a higher authorized recovery of electric and natural gas conservation expenditures. Conservation amortization is a pass-through tariff item with no impact on earnings.

Taxes other than income taxes increased $31.0 million, or 10.6%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase was primarily due to an increase in revenue sensitive taxes due to an increase in retail sales.

OTHER INCOME, INTEREST EXPENSE AND INCOME TAX EXPENSE

Other income increased $12.9 million, or 28.5%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase is primarily due to income related to the equity component of AFUDC. AFUDC increased $21.1 million for the year ended December 31, 2011, reflecting an increase in the average construction work in progress balance in 2011 due primarily to construction of wind and hydroelectric generation construction projects. This increase was partially offset by decreases in regulatory interest of $5.4 million, PTC of $1.2 million and conservative incentive of $1.2 million.

Interest expense decreased $19.4 million, or 8.8%, for the year ended December 31, 2011 as compared to the same period in 2010. Contributing to the decrease was a increase of $15.8 million in the debt component of AFUDC for the year ended December 31, 2011 which was included as construction expenditures and which was due to an increase in the average construction work in progress balance in 2011. Also contributing to the decrease is $3.2 million due to lower interest expense on the REC liability owed to customers.

Income tax expense increased $78.0 million for the year ended December 31, 2011 as compared to the same period in 2010. The increase was primarily related to higher pre-tax income.

2010 COMPARED TO 2009

OTHER OPERATING EXPENSES

Net unrealized (gain) loss on derivative instruments decreased by $168.2 million to a loss of $167.0 million in 2010, as compared to a gain of $(1.3) million in 2009. The loss was primarily due to the decline in wholesale energy prices during 2010 which resulted in unrealized losses on contracts for future deliveries of energy commodities which we record as derivative instruments. On July 1, 2009, PSE elected to de-designate its energy related derivative contracts previously designated as cash flow hedges. The contracts that were de-designated were physical electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and for contracts initiated after such date, all mark-to-market accounting impacts are recognized through earnings. The amount previously recorded in accumulated OCI is transferred to earnings when the contracts settle or sooner, if management determines that the forecasted transaction is probable of not occurring. As a result, PSE will continue to experience the earnings impact of these reversals from OCI in future periods. Over the tenor of PSE's outstanding derivative contracts, the forward wholesale prices of electricity and natural gas declined 21.0% and 27.0%, respectively, from December 31, 2009 to December 31, 2010.

Merger and related costs associated with the merger with Puget Holdings incurred for the year ended December 31, 2010 decreased $23.9 million. These costs were due to one-time PSE employee compensation costs, expenses related to the termination of credit agreements, legal fees and deferred compensation liability increases triggered by the merger in 2009. Pursuant to the Washington Commission merger order commitments, PSE did not seek recovery of these costs in retail rates.

Depreciation expense increased $23.2 million, or 8.6%, for the year ended December 31, 2010 as compared to the same period in 2009. This increase was primarily due to new additions of electric, natural gas and common plant which were placed into service in 2010 and the full year effect of plant placed in service throughout 2009.

Amortization expense increased $8.1 million, or 12.8%, for the year ended December 31, 2010 as compared to the same period in 2009 due to the inclusion of Mint Farm and Wild Horse expansion operating and ownership costs in general rates effective April 8, 2010. PSE ceased deferral of these costs effective April 8, 2010. These increases were partially offset by a decrease in software amortization.

Conservation amortization increased $23.6 million, or 35.6%, for the year ended December 31, 2010 as compared to the same period in 2009. The increase was due to a higher authorized recovery of electric and natural gas conservation expenditures. Conservation amortization is a pass-through tariff item with no impact on earnings.

Taxes other than income taxes decreased $10.8 million, or 3.6%, for the year ended December 31, 2010 as compared to the same period in 2009. The decrease was primarily due to a decrease in revenue sensitive taxes due to lower retail sales which were partially offset by an increase in property taxes.

OTHER INCOME, INTEREST EXPENSE AND INCOME TAX EXPENSE

Other income decreased $7.7 million, or 14.5%, for the year ended December 31, 2010 as compared to the same period in 2009. The decrease was primarily due to the carrying costs associated with the Mint Farm regulatory asset being included in general rates effective April 8, 2010. Prior to April 8, 2010, the Mint Farm regulatory asset was accruing interest income as authorized by the Washington Commission. Also contributing to the decrease was a $7.0 million decrease due to the Washington Commission AFUDC. These decreases were partially offset by an $8.5 million increase in AFUDC equity income.

Interest expense increased $18.3 million, or 9.0%, for the year ended December 31, 2010 as compared to the same period in 2009. The increase was primarily due to a write off of a regulatory asset of deferred interest paid to the IRS of $6.9 million related to the Simplified Service Cost Method deduction from prior years which was disallowed in the Washington Commission general rate case order of April 2, 2010. Also impacting the increase was higher long-term debt outstanding and interest on regulatory liability associated with RECs.

Income tax expense decreased $67.5 million or 99.8%, for the year ended December 31, 2010 as compared to the same period in 2009. The decrease was primarily related to lower pre-tax income.

PUGET ENERGY

All the operations of Puget Energy are conducted through its subsidiary PSE. "Predecessor" refers to the operations of Puget Energy and PSE prior to the consummation of the merger on February 6, 2009. "Successor" refers to the operations of Puget Energy and PSE subsequent to the merger. Puget Energy accounted for the merger as a business combination and all its assets and liabilities were recorded at fair value as of the merger date with the remaining consideration recorded as goodwill. The fair values of assets are being amortized over their estimated useful lives in a manner that best reflects the economic benefits derived from such assets. Goodwill is not amortized, but is subject to impairment testing on an annual basis. Such adjustments to fair value and the allocation of purchase price between identifiable intangibles and goodwill will have an impact on Puget Energy's expenses and profitability.

Puget Energy's net income for the years ended December 31, 2011, 2010 and 2009 was as follows:

Benefit/(Expense) (Dollars in Thousands)	Year Ended December 31, 2011	Year Ended December 31, 2010	2011-2010 Percent Change	Successor February 6, 2009 – December 31, 2009	Predecessor January 1, 2009 – February 5, 2009	2009 Combined	2010-2009 Percent Change
PSE net income	$ 204,120	$ 26,095	*%	$ 127,641	$ 31,611	$ 159,252	(83.6)%
Other operating revenue	(1,037)	--	*	361	--	361	*
Purchased electricity	578	578	--	529	--	529	9.3
Net unrealized gain on derivative instruments	42,652	112,858	(62.2)	151,481	--	151,481	(25.5)
Non-utility expense and other	1,704	(12,793)	(113.3)	(2,249)	(4)	(2,253)	*
Merger and related costs	--	--	--	(2,731)	(20,416)	(23,147)	*
Depreciation and amortization	--	--	--	167	--	167	*
Charitable contribution expense	--	--	--	(5,000)	--	(5,000)	*
Other income	10	43	(76.7)	--	--	--	*
Unhedged interest rate derivative expense	(28,601)	(7,955)	*	--	--	--	*
Interest expense [1]	(140,493)	(86,156)	63.1	(71,250)	25	(71,225)	21.0
Income tax benefit (expense)	44,357	(2,359)	*	(24,934)	1,540	(23,394)	(89.9)
Puget Energy net income	$ 123,290	$ 30,311	*%	$ 174,015	$ 12,756	$ 186,771	(83.8)%

* *Not meaningful*

1 *Puget Energy's interest expense includes elimination adjustments of intercompany interest on short-term debt.*

2011 COMPARED TO 2010

Summary Results of Operations

Puget Energy's net income for 2011 was $123.3 million with operating revenue of $3,318.8 million as compared to net income of $30.3 million with operating revenue of $3,122.2 million for 2010. The following are significant factors that impacted Puget Energy's net income which are not included in PSE's discussion:

Net unrealized gain on derivative instruments decreased $70.2 million for the year ended December 31, 2011, as compared to the same period in 2010, due to the effects of purchase accounting and the fair value amortization of derivative contracts. The forward prices of electricity and natural gas declined 25.7% and 23%, respectively for the year ended December 31, 2011.

Non-utility expense and other costs decreased $14.5 million for the year ended December 31, 2011, as compared to the same period in 2010, due primarily to the write down of SO2 emissions allowance inventory of $9.0 million in 2010 that did not occur in 2011. Also contributing to this decrease is a $4.9 million change related to qualified pension plan which resulted in a gain in 2011.

Unhedged interest rate derivative expense increased $20.6 million for the year ended December 31, 2011, as compared to the same period in 2010, as a result of paying down a portion of a five-year term-loan due February 2014 in December 2010 and during 2011. The five-year variable rate term-loan was initially fully hedged; however a portion of the hedge was unwound during the current year ended December 31, 2011.

Interest expense increased $54.3 million for the year ended December 31, 2011, as compared to the same period in 2010 due to increased out standing debt. In December 2010 and during 2011, Puget Energy issued fixed rate notes with higher interest rates to refinance and extend the debt maturity of a portion of a five-year term-loan due February 2014.

Income tax expense decreased $46.7 million for the year ended December 31, 2011, as compared to the same period in 2010, due primarily to higher pre-tax loss.

2010 COMPARED TO 2009

Summary Results of Operations

Puget Energy's net income for 2010 was $30.3 million with operating revenue of $3,122.2 million as compared to net income of $186.8 million with operating revenue of $3,328.5 million for 2009. The following are significant factors that impacted Puget Energy's net income which are not included in PSE's discussion:

Net unrealized gain on derivative instruments decreased $38.6 million for the year ended December 31, 2010, as compared to the same period in 2009, as a result of the required recognition of all contracts at fair value as part of purchase accounting, including derivative contracts previously designated as Normal Purchase Normal Sale (NPNS). Certain of these contracts were subsequently redesignated as NPNS. The unrealized gain represents the change in fair value of derivative contracts.

Non-utility expense and other costs increased $10.5 million for the year ended December 31, 2010, as compared to the same period in 2009, due primarily to the write down of SO2 emissions allowance inventory of $7.9 million.

Merger and related costs decreased $23.1 million for the year ended December 31, 2010, as compared to the same period in 2009, due to one-time merger related costs of compensation triggered by Puget Energy's change of control, excise taxes and financial advisor fees.

Unhedged interest rate derivative expense increased $8.0 million for the year ended December 31, 2010, as compared to the same period in 2009, due to the de-designation of interest rate swaps associated with the portion of the term-loan that was paid off on December 6, 2010.

Charitable contribution expense decreased $5.0 million for the year ended December 31, 2010, as compared to the same period in 2009, due to a charitable contribution to the PSE Foundation in 2009.

Interest expense increased $14.9 million for the year ended December 31, 2010, as compared to the same period in 2009. The increase was primarily due to the write-down of unamortized loan issuance costs associated with the portion of the term-loan paid off on December 6, 2010, business combination fair value amortization adjustments related to PSE's long-term debt and deferred debt costs.

Income tax expense decreased $21.0 million for the year ended December 31, 2010, as compared to the same period in 2009, primarily due to a decrease in pre-tax income combined with a decrease in the effective tax rate.

CAPITAL RESOURCES AND LIQUIDITY

CAPITAL REQUIREMENTS

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following are PSE's and Puget Energy's aggregate contractual obligations as of December 31, 2011:

CONTRACTUAL OBLIGATIONS (DOLLARS IN THOUSANDS)	PAYMENTS DUE PER PERIOD TOTAL	2012	2013-2014	2015-2016	THEREAFTER
Energy purchase obligations [1]	$ 5,428,718	$ 875,362	$ 1,377,807	$ 1,070,421	$ 2,105,128
Long-term debt including interest [2]	9,172,751	227,602	467,060	838,275	7,639,814
Short-term debt including interest [7,8]	55,076	55,076	--	--	--
Service contract obligations [3]	418,108	70,529	106,466	78,375	162,738
Non-cancelable operating leases [4]	128,095	13,873	27,095	27,889	59,238
PSE capital leases [4]	35,358	8,160	16,320	10,878	--
Pension and other benefits funding and payments [5]	72,392	30,291	7,955	9,041	25,105
Total PSE contractual cash obligations	$15,310,498	$ 1,280,893	$ 2,002,703	$ 2,034,879	$ 9,992,023
Long-term debt, including interest [6]	2,426,122	97,938	1,003,994	118,500	1,205,690
Less: Inter-company short-term debt and interest elimination [7]	(30,037)	(30,037)	--	--	--
Total Puget Energy contractual cash obligations	$17,706,583	$ 1,348,794	$ 3,006,697	$ 2,153,379	$11,197,713

1 *Energy purchase contracts were entered into as part of PSE's obligation to serve retail electric and natural gas customers' energy requirements. As a result, costs are generally recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost adjustment mechanisms.*
2 *For individual long-term debt maturities, see Note 7 to the consolidated financial statements included in Item 8 of this report. For Puget Energy the amount above excludes the fair value adjustments related to the merger.*
3 *Represents operational agreements, settlements and other contractual obligations with respect to generation, transmission and distribution facilities. These costs are generally recovered through base retail rates.*
4 *For additional information, see Note 10 to the consolidated financial statements included in Item 8 of this report.*
5 *Pension and other benefit expected contributions represent PSE's estimated cash contributions to the pension plan through 2016.*
6 *As of December 31, 2011, Puget Energy had fully drawn on a five-year term-loan with a balance of $298.0 million and incurred a $545.0 million draw under its $1.0 billion Puget Energy capital expenditure facility.*
7 *As of December 31, 2011, PSE has a revolving credit facility with Puget Energy in the form of a promissory note to borrow up to $30.0 million of which $30.0 million was drawn.*
8 *As of December 31, 2011, PSE had credit facilities totaling $1.15 billion of which $37.5 million had been drawn. These facilities consisted of $400.0 million to fund operating expenses, $400.0 million to fund capital expenditures and $350.0 million to support electric and natural gas hedging. In addition, a $12.5 million letter of credit was outstanding under the $400.0 million working capital facility.*

The following are PSE's and Puget Energy's aggregate availability under commercial commitments as of December 31, 2011:

COMMERCIAL COMMITMENTS (DOLLARS IN THOUSANDS)	AMOUNT OF AVAILABLE COMMITMENTS EXPIRATION PER PERIOD TOTAL	2012	2013-2014	2015-2016	THEREAFTER
PSE working capital facility [1]	$ 362,539	$ --	$ 362,539	$ --	$ --
PSE capital expenditures facility [1]	400,000		400,000	--	--
PSE energy hedging facility [1]	350,000		350,000	--	--
Inter-company short-term debt [2]	--	--	--	--	--
Total PSE commercial commitments	$1,112,539	$ --	$1,112,539	$ --	$ --
Puget Energy capital expenditures facility [3]	455,000	--	455,000	--	--
Less: Inter-company short-term debt elimination [2]	--	--	--	--	--
Total Puget Energy commercial commitments	$1,567,539	$ --	$1,567,539	$ --	$ --

1 *As of December 31, 2011, PSE had credit facilities totaling $1.15 billion of which $37.5 million had been drawn. These facilities consisted of $400.0 million to fund operating expenses, $400.0 million to fund capital expenditures and $350.0 million to support electric and natural gas hedging. In addition, a $12.5 million letter of credit was outstanding under the $400.0 million working capital facility.*
2 *As of December 31, 2011, PSE had a revolving credit facility with Puget Energy in the form of a promissory note to borrow up to $30.0 million of which $30.0 million was drawn.*
3 *As of December 31, 2011, Puget Energy had fully drawn on a five-year term-loan with a balance of $298.0 million and incurred a $545.0 million draw under its $1.0 billion Puget Energy capital expenditure facility.*

UTILITY CONSTRUCTION PROGRAM

PSE's construction programs for generating facilities, the electric transmission system and the natural gas and electric distribution systems are designed to meet regulatory requirements, customer growth and to support reliable energy delivery. Construction expenditures, excluding equity AFUDC, totaled $976.5 million in 2011. As a result of a general slowing in the economy and changes to the Company's proposed resources, PSE's projected construction expenditures have been reduced. Presently planned utility construction expenditures, excluding AFUDC, for 2012, 2013 and 2014 are:

CAPITAL EXPENDITURE PROJECTIONS (DOLLARS IN THOUSANDS)	2012	2013	2014
Energy delivery, technology and facilities	$ 698,458	$ 632,400	$ 591,206
Total expenditures	$ 698,458	$ 632,400	$ 591,206

The program is subject to change to respond to general business, economic and regulatory conditions. Utility construction expenditures and any new generation resource expenditures required to meet future electric capacity supply shortfalls may be funded from a combination of sources that may include cash from operations, short-term debt, long-term debt and/or equity. PSE's planned capital expenditures result in a level of spending that will likely exceed its cash flow from operations. As a result, execution of PSE's strategy is dependent in part on continued access to the capital markets.

CAPITAL RESOURCES

CASH FROM OPERATIONS

PUGET SOUND ENERGY

Cash generated from operations for the year ended December 31, 2011 was $903.4 million, an increase of $327.6 million from the $575.8 million generated during the year ended December 31, 2010. The increase was primarily the result of the following:

- PSE's deferred taxes increased by $77.7 million in 2011 as compared to a decrease in 2010 of $16.3 million, causing an operating cash flow increase of $94.0 million.
- PSE's PGA mechanism had a $31.9 million overrecovery from customers during the year ended 2011 as compared to $55.6 million payments to customers related to an over collection of prior year plan-related rates during the same period in 2010, causing an operating cash flow increase of $87.5 million.
- Net income increased $178.0 million during the year ended 2011 as compared to the same period in 2010. This increase was caused by a non-cash unrealized derivative instruments loss reduction of $112.8 million, which resulted in operating cash flow increase of $65.2 million.
- Other long term liabilities increased by $28.8 million during the year ended 2011 as compared to an increase of $1.7 million during the same period in 2010, causing an operating cash flow increase of $27.1 million.
- PSE received net tax refunds of $50.0 million during the year ended 2011 as compared to net tax refunds of $20.6 million during the same period in 2010, causing an operating cash flow increase of $29.4 million.
- Material and supplies inventory increased $8.2 million during the year ended 2011 as compared to a decrease of $19.6 million during the same period in 2010, causing an operating cash flow increase of $27.8 million.
- Accounts payable increased by $0.7 million during the year ended 2011 as compared to a decrease of $25.8 million during the same period in 2010, causing an operating cash flow increase of $26.5 million.
- Prepaid income taxes increased by $50.6 million during the year ended 2011 as compared to an increase of $37.8 million during the same period in 2010, causing an operating cash flow increase of $12.7 million.

The increase in cash generated from operating activities in 2011 was partially offset by the following:

- AFUDC (equity component) decreased cash flows by $32.4 million during the year ended 2011 as compared to a decrease of $12.7 million during the same period in 2010, causing an operating cash flow decrease of $19.7 million. AFUDC primarily increased due to an increase in average construction work in progress balances.
- Accounts receivable and unbilled revenue increased by $6.2 million during the year ended 2011 as compared to a decrease of $7.6 million during the same period in 2010, causing an operating cash flow decrease of $13.8 million.

- Other long-term assets decreased by $60.0 million during the year ended 2011 as compared to a decrease of $48.3 million during the same period in 2010, causing an operating cash flow decrease of $11.7 million.

PUGET ENERGY

Cash generated from operations for the year ended December 31, 2011 was $1.0 billion, an increase of $144.4 million from the $865.9 million generated in 2010. The increase included $327.6 million from the cash provided by the operating activities of PSE as previously discussed. Other factors contributing to the increase included the following:

- Puget Energy's net unrealized loss (gain) on derivative instruments was a loss of $45.0 million during the year ended December 31, 2011 compared to a loss of $50.5 million in the same period in 2010, causing an increase in cash from operations of $107.4 million.
- Puget Energy's accrued expenses and other increased by $41.3 million compared to an increase of $10.1 million in the same period in 2010, causing an increase in cash from operations of $26.2 million.

The increase in cash generated from operating activities in 2011 was partially offset by the following:

- As a result of the merger, $182.7 million in derivative settlement payments were reclassified to financing activities during the year ended December 31, 2011 as compared to $371.6 million during the same period in 2010, resulting in a decrease in operating cash flows of $188.9 million. This decrease was due to a decline in the number of contracts settled during 2011 as compared to the prior period. These contracts represent proceeds received from derivative instruments that included financing elements at the merger date.
- Puget Energy's deferred tax savings decreased $27.8 million during the year ended December 31, 2011 as compared to the same period of the prior year, causing a decrease in cash from operations.

FINANCING PROGRAM

The Company's external financing requirements principally reflect the cash needs of its construction program, its schedule of maturing debt and certain operational needs. The Company anticipates refinancing the redemption of bonds or other long-term borrowings with its credit facilities and/or the issuance of new long-term debt. Access to funds depends upon factors such as Puget Energy's and PSE's credit ratings, prevailing interest rates and investor receptivity to investing in the utility industry, Puget Energy and PSE.

CREDIT FACILITIES AND COMMERCIAL PAPER

Proceeds from PSE's short-term borrowings and sales of commercial paper are used to provide working capital and the interim funding of utility construction programs. Puget Energy and PSE continue to have reasonable access to the capital and credit markets.

As of December 31, 2011 and 2010, PSE had $25.0 million and $247.0 million in short-term debt outstanding, respectively, exclusive of the demand promissory note with Puget Energy. Outside of the consolidation of PSE's short-term debt, Puget Energy had no short-term debt outstanding in either year as borrowing under its credit facilities are classified as long-term. PSE's weighted-average interest rate on short-term debt, including borrowing rate, commitment fees and the amortization of debt issuance costs, during 2011 and 2010 was 4.39%, and 5.11%, respectively. As of December 31, 2011, PSE and Puget Energy had several committed credit facilities that are described below.

PUGET SOUND ENERGY CREDIT FACILITIES

PSE maintains three committed unsecured revolving credit facilities that provide, in the aggregate, $1.15 billion in short-term borrowing capability and which mature concurrently in February 2014. These facilities include a $400.0 million credit agreement for working capital needs, a $400.0 million credit facility for funding capital expenditures and a $350.0 million facility to support energy hedging activities.

PSE's credit agreements contain usual and customary affirmative and negative covenants that, among other things, place limitations on PSE's ability to incur additional indebtedness and liens, issue equity, pay dividends, transact with affiliates and make asset dispositions and investments. The credit agreements also contain financial covenants which include a cash flow interest coverage ratio and, in addition, if PSE has a below investment grade credit rating, a cash flow to net debt outstanding ratio (each as specified in the facilities). PSE certifies its compliance with such covenants to participating banks each quarter. As of December 31, 2011, PSE was in compliance with all applicable covenants.

These credit facilities contain similar terms and conditions and are syndicated among numerous committed lenders. The agreements provide PSE with the ability to borrow at different interest rate options and include variable fee levels. The credit agreements allow PSE to borrow at the bank's prime rate or to make floating rate advances at the LIBOR plus a spread that is based upon PSE's credit rating. The working capital facility, as amended, includes a swing line feature allowing same day availability on borrowings up to $50.0 million. The $400.0 million working capital facility and $350.0 million credit agreement to support energy hedging allow for issuing standby letters of credit. PSE must also pay a commitment fee on the unused portion of the credit facilities. The spreads and the commitment fee depend on PSE's credit ratings. As of the date of this report, the spread to the LIBOR is 0.85% and the commitment fee is 0.26%. The $400.0 million working capital facility also serves as a backstop for PSE's commercial paper program.

As of December 31, 2011, $25.0 million was drawn and outstanding under PSE's $400.0 million working capital facility. A $12.5 million letter of credit supporting contracts was outstanding under the facility and there were no amounts outstanding under the commercial paper program. The $400.0 million capital expenditure facility had no amounts drawn and outstanding. No amounts were drawn or outstanding (including letters of credit) under PSE's $350.0 million facility supporting energy hedging. Outside of the credit agreements, PSE had a $5.3 million letter of credit in support of a long-term transmission contract.

Demand Promissory Note. On June 1, 2006, PSE entered into a revolving credit facility with Puget Energy, in the form of a credit agreement and a Demand Promissory Note (Note) pursuant to which PSE may borrow up to $30.0 million from Puget Energy subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lower of the weighted-average interest rates of PSE's outstanding commercial paper interest rate or PSE's senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. At December 31, 2011, the outstanding balance of the Note was $30.0 million. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements.

PUGET ENERGY CREDIT FACILITIES

At the time of the merger in February 2009, Puget Energy entered into a $1.225 billion five-year term-loan and a $1.0 billion capital expenditure facility for funding capital expenditures. As of December 31, 2011, Puget Energy had fully drawn the five-year term-loan which, after previous repayments, had a remaining outstanding balance of $298.0 million. Also, as of December 31, 2011, Puget Energy had drawn $545.0 million under the $1.0 billion capital expenditure facility. The term-loan and capital expenditure facility mature in February 2014. These credit agreements, which in May 2010 were amended to include a provision for the sharing of collateral with note holders, contained usual and customary affirmative and negative covenants similar to those in PSE's credit facilities. As of December 31, 2011, Puget Energy was in compliance with all applicable covenants.

On February 10, 2012, Puget Energy entered into a $1.0 billion five-year revolving credit facility. Initial borrowings under this facility were used to repay debt outstanding under Puget Energy's term loan and capital expenditure facilities and those agreements were terminated. As a revolving facility, amounts borrowed may be repaid without a reduction in the size of the facility. The revolving credit facility provides Puget Energy the ability to borrow at different interest rate options and includes variable fee levels. Interest rates may be based on the prime rate or LIBOR, plus a spread based on Puget Energy's credit ratings. Puget Energy must pay a commitment fee on the unused portion of the facility. At the inception of this facility, $864.0 million was outstanding, the spread over LIBOR was 2.0% and the commitment fee was 0.375%.

DIVIDEND PAYMENT RESTRICTIONS

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE's electric and natural gas mortgage indentures. At December 31, 2011, approximately $448.6 million of unrestricted retained earnings was available for the payment of dividends under the most restrictive mortgage indenture covenant.

Beginning February 6, 2009, pursuant to the terms of the Washington Commission merger order, PSE may not declare or pay dividends if PSE's common equity ratio, calculated on a regulatory basis, is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. Also, pursuant to the merger order, PSE may not declare or make any distribution unless on the date of distribution PSE's corporate credit/issuer rating is investment grade, or, if its credit ratings are below investment grade, PSE's ratio of EBITDA to interest expense for the most recently ended four fiscal quarter periods prior to such date is equal to or greater than 3 to one. The common equity ratio, calculated on a regulatory basis, was 48.2% at December 31, 2011 and the EBITDA to interest expense was 4.4 to one for the 12 months then ended.

PSE's ability to pay dividends is also limited by the terms of its credit facilities, pursuant to which PSE is not permitted to pay dividends during any Event of Default, or if the payment of dividends would result in an Event of Default (as defined in the facilities), such as failure to comply with certain financial covenants.

Puget Energy's ability to pay dividends is also limited by the merger order issued by the Washington Commission as well as by the terms of its credit facilities. Pursuant to the merger order, Puget Energy may not declare or make a distribution unless on such date Puget Energy's ratio of consolidated EBITDA to consolidated interest expense for the four most recently ended fiscal quarters prior to such date is equal to or greater than 2 to one. At December 31, 2011, the EBITDA to interest expense was 2.7 to one for the 12 months then ended.

In accordance with terms of the Puget Energy credit facilities, Puget Energy is limited to paying a dividend within an eight-day period that begins seven days following the delivery of quarterly or annual financial statements to the facility agent. Puget Energy is not permitted to pay dividends during any Event of Default, or if the payment of dividends would result in an Event of Default (as defined in the facilities), such as failure to comply with certain financial covenants. In addition, in order to declare or pay unrestricted dividends, Puget Energy's interest coverage ratio may not be less than 1.5 to one and its cash flow to net debt outstanding ratio may not be less than 8.25% for the 12 months ending each quarter-end. Puget Energy is also subject to other restrictions such as a "lock up" provision that, in certain circumstances, such as failure to meet certain cash flow tests, may further restrict Puget Energy's ability to pay dividends.

At December 31, 2011, the Company was in compliance with all applicable covenants, including those pertaining to the payment of dividends.

DEBT RESTRICTIVE COVENANTS

The type and amount of future long-term financing for Puget Energy and PSE are limited by provisions in their credit agreements and PSE's mortgage indentures. Under its credit agreements, Puget Energy is generally limited to permitted refinancings and borrowings under its credit facilities and by restrictions placed upon its subsidiaries. One such restriction limits PSE's long-term debt issuances to not exceed $500.0 million per year, plus any amount needed to refinance maturing bonds. Unused amounts under this limitation may be carried forward into future years. Puget Energy's facilities contain a provision whereby additional capital expenditure loans up to $750.0 million may, under certain conditions, be made available after the $1.0 billion capital expenditure commitment has been fully borrowed.

PSE's ability to issue additional secured debt may be limited by certain restrictions contained in its electric and natural gas mortgage indentures. Under the most restrictive tests, at December 31, 2011, PSE could issue:

- Approximately $1.3 billion of additional first mortgage bonds under PSE's electric mortgage indenture based on approximately $2.1 billion of electric bondable property available for issuance, subject to an interest coverage ratio limitation of 2.0 times net earnings available for interest (as defined in the electric utility mortgage), which PSE exceeded at December 31, 2011; and
- Approximately $213.0 million of additional first mortgage bonds under PSE's natural gas mortgage indenture based on approximately $355.0 million of gas bondable property available for issuance, subject to a combined gas and electric interest coverage test of 1.75 times net earnings available for interest and a gas interest coverage test of 2.0 times net earnings available for interest (as defined in the natural gas utility mortgage), both of which PSE exceeded at December 31, 2011.

At December 31, 2011, PSE had approximately $5.8 billion in electric and natural gas ratebase to support the interest coverage ratio limitation test for net earnings available for interest.

SHELF REGISTRATIONS AND LONG-TERM DEBT ACTIVITY

Puget Sound Energy. PSE has in effect a shelf registration statement under which it may issue, from time to time, senior notes secured by first mortgage bonds. The Company remains subject to the restrictions of PSE's indentures and credit agreements on the amount of first mortgage bonds that PSE may issue.

On March 25, 2011, PSE issued $300.0 million of Senior Notes secured by first mortgage bonds. The notes have a term of 30 years and an interest rate of 5.638%. Net proceeds from the note offering were used by PSE to repay short-term debt outstanding under its capital expenditure credit facility, which debt was incurred to fund utility capital expenditures and replenish cash used to repay the February 2011 maturity of $260.0 million medium-term notes with a 7.69% interest rate.

On November 16, 2011, PSE issued $250.0 million of 4.434% Senior Secured Notes at par with a 30-year maturity. Net proceeds from the note offering were used by PSE to repay short-term indebtedness under the Company's capital expenditure credit facility, which was primarily used to finance new facilities such as the Lower Snake River (LSR) Wind Project.

On November 22, 2011, PSE issued $45.0 million of 4.700% Senior Secured Notes at par with a 40-year maturity. Net proceeds from the note offering were used to redeem early, on December 23, 2011, $25.0 million of 9.57% first mortgage bonds previously issued under the company's gas mortgage indenture. The remainder of the proceeds were used to pay down short-term indebtedness under the Company's capital expenditure credit facility.

Puget Energy. On June 3, 2011, Puget Energy issued $500.0 million of senior secured notes in a private placement. The notes have a term of 10 years and 3 months and mature on September 1, 2021. The interest rate on the notes is 6.0%. The notes are secured by an interest in substantially all of Puget Energy's assets, which consists mainly of all the issued and outstanding stock of PSE and the stock of Puget Energy held by Puget Equico. The notes contain a change of control provision pursuant to which holders of the notes may have the right to require Puget Energy to repurchase all or any part of the notes at a purchase price in cash equal to 101.0% of the principal amount of the notes, plus accrued and unpaid interest. Net proceeds from the issue of the notes were used to repay a portion of the $782.0 million remaining balance on the $1.225 billion Puget Energy five-year term-loan and retire a portion of the interest rate hedges associated with that loan.

On June 17, 2011, Puget Energy exchanged $449.9 million of its $450.0 million 6.5% senior secured notes that were originally issued in a December 2010 private placement for registered notes.

On August 10, 2011, Puget Energy exchanged $500.0 million of its 6.0% senior secured notes that were originally issued in the June 2011 private placement for registered notes of the same amount.

OTHER

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. The following accounting policies represent those that management believes are particularly important to the financial statements and that require the use of estimates, assumptions and judgment to describe matters that are inherently uncertain.

Revenue Recognition. Operating utility revenue is recognized when service is rendered, and includes estimated unbilled revenue. Unbilled electric revenue is determined by taking system load less estimated losses and billed MWh plus the beginning unbilled MWh balance. The estimated system loss percentage for electricity is determined by reviewing historical billed MWh to system load. The estimated unbilled MWh balance is then multiplied by the estimated average revenue per MWh. Unbilled natural gas revenue is determined by taking therms delivered to PSE less estimated system losses, prior month unbilled therms and billed therms. The estimated system loss percentage for natural gas is determined by reviewing historical billed therms to therms delivered to customers, which vary little from year to year. The estimated current month unbilled therms is then multiplied by an average rate per schedule per therm based on billed revenue for the month.

Regulatory Accounting. As a regulated entity of the Washington Commission and the FERC, PSE prepares its financial statements in accordance with the provisions of ASC 980, "Regulated Operations" (ASC 980). The application of ASC 980 results in differences in the timing and recognition of certain revenue and expenses in comparison with businesses in other industries. The rates that are charged by PSE to its customers are based on cost base regulation reviewed and approved by the Washington Commission and the FERC. Under the authority of these commissions, PSE has recorded certain regulatory assets and liabilities at December 31, 2011 in the amount of $848.1 million and $366.8 million, respectively, and regulatory assets and liabilities at December 31, 2010 of $887.6 million and $296.9 million, respectively. In conjunction with the merger, Puget Energy recognized additional regulatory assets of $297.1 million and liabilities of $1.05 billion, reflecting the regulatory treatment of certain assets and liabilities subject to purchase accounting. Such amounts are amortized through a corresponding liability or asset account, respectively, with no impact to earnings. PSE expects to fully recover its regulatory assets and liabilities through its rates. If future recovery of costs ceases to be probable, PSE would be required to write off these regulatory assets and liabilities. In addition, if PSE determines that it no longer meets the criteria for continued application of ASC 980, PSE could be required to write off its regulatory assets and liabilities related to those operations not meeting ASC 980 requirements.

Also encompassed by regulatory accounting and subject to ASC 980 are the PCA and PGA mechanisms. The PCA and PGA mechanisms mitigate the impact of commodity price volatility upon the Company and are approved by the Washington Commission. The PCA mechanism provides for a sharing of costs that vary from baseline rates over a graduated scale. For further discussion regarding the PCA mechanism, see Electric Regulation and Rates within Item 1. Business – Regulation and Rates of this report. The PGA mechanism passes increases and decreases in the cost of natural gas supply through to customers. PSE expects to fully recover these regulatory assets through its rates. However, both mechanisms are subject to regulatory review and approval by the Washington Commission on a periodic basis.

Goodwill. On February 6, 2009, Puget Holdings completed its merger with Puget Energy. Puget Energy remeasured the carrying amount of all its assets and liabilities to fair value, which resulted in recognition of approximately $1.7 billion in goodwill. ASC 350, “Intangibles - Goodwill and Other,” (ASC 350) requires that goodwill be tested for impairment at the reporting unit level on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. These events or circumstances could include a significant change in the Company’s business or regulatory outlook, legal factors, a sale or disposition of a significant portion of a reporting unit or significant changes in the financial markets which could influence the Company’s access to capital and interest rates. Application of the goodwill impairment test requires judgment, including the identification of reporting units, assignment of assets and liabilities to reporting units, assignment of goodwill to reporting units and the determination of the fair value of the reporting units. Management has determined Puget Energy has only one reporting unit.

The goodwill recorded by Puget Energy represents the potential long-term return to the Company’s investors. Goodwill is tested for impairment annually using a two-step process. The first step compares the carrying amount of the reporting unit with its fair value, with a carrying value higher than fair value indicating potential impairment. If the first step test fails, the second step is performed. This would entail a full valuation of Puget Energy’s assets and liabilities and comparing the valuation to its carrying amounts, with the aggregate difference indicating the amount of impairment. Goodwill of a reporting unit is required to be tested for impairment on an interim basis if an event occurs or circumstances change that would cause the fair value of a reporting unit to fall below its carrying amount.

Puget Energy conducted its most recent annual impairment test as of October 1, 2011. The fair value of Puget Energy’s reporting unit was estimated using the weighted-averages from an income valuation method, or discounted cash flow method, and a market valuation approach. These valuations required significant judgments, including: (1) estimation of future cash flows, which is dependent on internal forecasts, (2) estimation of the long-term rate of growth for Puget Energy’s business, (3) estimation of the useful life over which cash flows will occur, (4) the selection of utility holding companies determined to be comparable to Puget Energy, and (5) the determination of an appropriate weighted-average cost of capital or discount rate.

Management estimated the fair value of Puget Energy’s equity to be approximately $3.9 billion at the October 1, 2011 measurement date for the annual test of goodwill impairment. The carrying value of Puget Energy’s equity was approximately $3.3 billion with the excess of the fair value over the carrying value representing 16.9%.

The income approach and the market approach valuations resulted in Puget Energy equity values of $4.1 billion and $3.6 billion, respectively. The result of the income approach was very sensitive to long-term cash flow growth rates applicable to periods beyond management’s five-year business plan and financial forecast period and the weighted-average cost of capital assumptions of 3.0% and 7.0%, respectively.

The following table summarizes the results of the income valuation method:

Equity Value Sensitivity Table (Dollars in Billions)	Long-Term Growth Rate		
Weighted-Average Cost of Capital	2.7%	3.0%	3.3%
7.1%	$ 3.2	$ 3.9	$ 4.5
7.0	3.5	4.1	4.8
6.9	3.7	4.4	5.1

Derivatives. ASC 815, “Derivatives and Hedging” (ASC 815), requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value unless the contracts qualify for an exception. The Company enters into derivative contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts and swaps. Some of PSE's physical electric supply contracts qualify for the Normal Purchase Normal Sale (NPNS) exception to derivative accounting rules. Generally, NPNS applies to contracts with creditworthy counterparties, for which physical delivery is probable and in quantities that will be used in the normal course of business. Power purchases designated as NPNS must meet additional criteria to determine if the transaction is within PSE's forecasted load requirements and if the counterparty owns or controls energy resources within the western region to allow for physical delivery of the energy. PSE may enter into financial fixed contracts to economically hedge the variability of certain index-based contracts. Those contracts that do not meet the NPNS exception are marked-to-market to current earnings in the statements of income, subject to deferral under ASC 980, for energy related derivatives due to the PCA mechanism and PGA mechanism.

On July 1, 2009, Puget Energy and PSE elected to de-designate all energy related derivative contracts previously recorded as cash flow hedges for the purpose of simplifying its financial reporting. The contracts that were de-designated related to physical electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and contracts initiated after such date, all mark-to-market adjustments are recognized through earnings. The amount previously recorded in accumulated OCI is transferred to earnings in the same period or periods during which the hedged transaction affects earnings or sooner if management determines that the forecasted transaction is probable of not occurring. As a result, the Company will continue to experience the earnings impact of these reversals from OCI in future periods.

PSE values derivative instruments based on daily quoted prices from an independent external pricing service. The Company regularly confirms the validity of pricing service quoted prices (e.g. Level 2 in the fair value hierarchy) used to value commodity contracts to the actual prices of commodity contracts entered into during the most recent quarter. When external quoted market prices are not available for derivative contracts, PSE uses a valuation model that uses volatility assumptions relating to future energy prices based on specific energy markets and utilizes externally available forward market price curves. All derivative instruments are sensitive to market price fluctuations that can occur on a daily basis. The Company is focused on commodity price exposure and risks associated with volumetric variability in the natural gas and electric portfolios. It is not engaged in the business of assuming risk for the purpose of speculative trading. The Company economically hedges open natural gas and electric positions to reduce both the portfolio risk and the volatility risk in prices. The exposure position is determined by using a probabilistic risk system that models 250 simulations of how the Company's natural gas and power portfolios will perform under various weather, hydrological and unit performance conditions.

The Company may enter into swap instruments or other financial derivative instruments to manage the interest rate risk associated with its long-term debt financing and debt instruments. As of December 31, 2011, Puget Energy had interest rate swap contracts outstanding related to its long-term debt. For additional information, see Item 7A and Note 12 to the consolidated financial statements included in Item 8 of this report.

Fair Value. ASC 820, "Fair Value Measurements and Disclosures" (ASC 820), defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). However, as permitted under ASC 820, the Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of its assets and liabilities measured and reported at fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements as it believes that this approach is used by market participants for these types of assets and liabilities. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. For further discussion on market risk, see Item 7A of this report.

On February 6, 2009, Puget Holdings completed its merger with Puget Energy. Puget Energy remeasured the carrying amount of all its assets and liabilities to fair value, which resulted in recognition of approximately $1.7 billion in goodwill. For additional information on purchase accounting adjustments and fair value measurements, see Note 3 and Note 14 to the consolidated financial statements included in Item 8 of this report, respectively.

Pension and Other Postretirement Benefits. PSE has a qualified defined benefit pension plan covering substantially all employees of PSE. PSE recognized qualified pension expense of $6.6 million, expense of $8.0 million and income of $3.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. Of these amounts, approximately 61.0%, 61.1% and 61.2% were included in utility operations and maintenance expense in 2011, 2010 and 2009, respectively, and the remaining amounts were capitalized. For the years ended December 31, 2011 and 2010, Puget Energy recognized incremental qualified pension income of $1.9 million and pension expense of $3.0 million, respectively. In 2012, it is expected that PSE and Puget Energy will recognize pension expense of $14.7 million and $9.4 million of pension income, respectively.

PSE has a Supplemental Executive Retirement Plan (SERP). PSE recognized pension and other postretirement benefit expenses of $5.2 million, $4.5 million and $4.9 million for the years ended December 31, 2011, 2010 and 2009, respectively. For the years ended December 31, 2011 and 2010, Puget Energy recognized incremental income of $1.4 million and $1.3 million, respectively. In 2012, it is expected PSE and Puget Energy will recognize $5.0 million of pension expense and $1.0 million of pension income, respectively.

PSE has other limited postretirement benefit plans. PSE recognized expense of $0.1 million, expense of $0.1 million and expense of $0.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. For the years ended December 31, 2011 and 2010, Puget Energy recognized incremental expense of $0.3 million and $0.3 million, respectively. In 2012, it is expected that PSE and Puget Energy will recognize expense of $0.3 million and $0.2 million, respectively.

Due to the merger, the pension plan, SERP plan and other poster retirements benefit plans were remeasured in accordance with ASC 805. For further information on the business combination, see Note 3 to the consolidated financial statements included in Item 8 of this report.

The Company's pension and other postretirement benefits income or expense depend on several factors and assumptions, including plan design, timing and amount of cash contributions to the plan, earnings on plan assets, discount rate, expected long-term rate of return, mortality and health care cost trends. Changes in any of these factors or assumptions will affect the amount of income or expense that the Company records in its financial statements in future years and its projected benefit obligation. The Company has selected an expected return on plan assets based on a historical analysis of rates of return and the Company's investment mix, market conditions, inflation and other factors. The Company's accounting policy for calculating the market-related value of assets is based on a five-year smoothing of asset gains or losses measured from the expected return on market-related assets. This is a calculated value that recognizes changes in fair value in a systematic and rational manner over five years. The same manner of calculating market-related value is used for all classes of assets, and is applied consistently from year to year. As required by merger accounting rules, market-related value was reset to market value effective with the merger. During 2011, the Company made a cash contribution of $5.0 million to the qualified defined benefit plan. Management is closely monitoring the funding status of its qualified pension plan given the recent volatility of the financial markets. The aggregate expected contributions and payments by the Company to fund the retirement plan, SERP and other postretirement plans for the year ending December 31, 2012 are expected to be at least $22.8 million, $6.1 million and $0.9 million, respectively.

The following tables reflect the estimated sensitivity associated with a change in certain significant actuarial assumptions (each assumption change is presented mutually exclusive of other assumption changes):

Puget Energy and Puget Sound Energy	Change in Assumption	Impact on Projected Benefit Obligation Increase /(Decrease)		
(Dollars in Thousands)		Pension Benefits	SERP	Other Benefits
Increase in discount rate	50 basis points	$(29,045)	$(2,059)	$(722)
Decrease in discount rate	50 basis points	31,920	2,220	783

Puget Energy	Change in Assumption	Impact on 2011 Pension Expense Increase /(Decrease)		
(Dollars in Thousands)		Pension Benefits	SERP	Other Benefits
Increase in discount rate	50 basis points	$ (15)	$(187)	$(53)
Decrease in discount rate	50 basis points	2,189	196	51
Increase in return on plan assets	50 basis points	(2,209)	*	(39)
Decrease in return on plan assets	50 basis points	2,209	*	37

PUGET SOUND ENERGY	CHANGE IN ASSUMPTION	IMPACT ON 2011 PENSION EXPENSE INCREASE /(DECREASE)		
(DOLLARS IN THOUSANDS)		PENSION BENEFITS	SERP	OTHER BENEFITS
Increase in discount rate	50 basis points	$(2,450)	$(187)	$(61)
Decrease in discount rate	50 basis points	2,666	196	65
Increase in return on plan assets	50 basis points	(2,758)	*	(38)
Decrease in return on plan assets	50 basis points	2,758	*	38

* *Calculation not applicable.*

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

For the discussion of recently adopted accounting pronouncements, see Note 2 to the consolidated financial statements included in Item 8 of this report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ENERGY PORTFOLIO MANAGEMENT

PSE maintains energy risk policies and procedures to manage commodity and volatility risks and the related effects on credit, tax accounting, financing and liquidity. PSE's Energy Management Committee establishes PSE's risk management policies and procedures and monitors compliance. The Energy Management Committee is comprised of certain PSE officers and is overseen by the PSE Board of Directors.

PSE is focused on the commodity price exposure and risks associated with volumetric variability in the natural gas and electric portfolios and related effects noted above, and is not engaged in the business of assuming risk for the purpose of speculative trading. PSE hedges open gas and electric positions to reduce both the portfolio risk and the volatility risk in prices. The exposure position is determined by using a probabilistic risk system that models 250 simulations of how PSE's natural gas and power portfolios will perform under various weather, hydroelectric and unit performance conditions. The objectives of the hedging strategy are to:

- Ensure physical energy supplies are available to reliably and cost-effectively serve retail load;
- Manage the energy portfolio prudently to serve retail load at overall least cost and limit undesired impacts on PSE's customers and shareholders;
- Reduce power costs by extracting the value of PSE's assets; and
- Meet the credit, liquidity, financing, tax and accounting requirements of PSE.

ASC 815 requires a significant amount of disclosure regarding PSE's derivative activities and the nature of such derivatives impact on PSE's financial position, financial performance and cash flows. The information in this Item 7A should serve as an accompaniment to Management's Discussion and Analysis and Note 11 to the consolidated financial statements included in Items 7 and 8 of this report, respectively.

PSE employs various portfolio optimization strategies but is not in the business of assuming risk for the purpose of realizing speculative trading revenue. PSE's portfolio of owned and contracted electric generation resources exposes PSE and its retail electric customers to volumetric and commodity price risks within the sharing mechanism of the PCA. PSE's natural gas retail customers are served by natural gas purchase contracts which expose PSE's customers to commodity price risks through the PGA mechanism. All purchased natural gas costs are recovered through customer rates with no direct impact on PSE. Therefore, wholesale market transactions are focused on balancing PSE's energy portfolio, reducing costs and risks where feasible and reducing volatility. PSE's energy risk portfolio management function monitors and manages these risks. In order to manage risks effectively, PSE enters into forward physical electricity and natural gas purchase and sale agreements, and floating for fixed swap contracts that are related to its regulated electric and natural gas portfolios. The forward physical electricity contracts are both fixed and variable (at index) while the physical natural gas contracts are variable with investment grade counterparties that do not require collateral calls on the contracts. To fix the price of natural gas, PSE may enter into natural gas floating for fixed swap (financial) contracts with various counterparties.

On July 1, 2009, Puget Energy and PSE elected to de-designate all energy related derivative contracts previously recorded as cash flow hedges for the purpose of simplifying its financial reporting. The contracts that were de-designated related to physical electric supply contracts and natural gas swap contracts to fix the price of natural gas for electric generation. For these contracts and contracts initiated after such date, all mark-to-market adjustments are recognized through earnings. The amount previously recorded in accumulated OCI is transferred to earnings in the same period or periods during which the hedged transaction affected earnings or sooner if management determines that the forecasted transaction is probable of not occurring. As a result, the Company will continue to experience the earnings impact of these reversals from OCI in future periods.

The following tables present the Company's energy derivatives instruments that do not meet the NPNS exception at December 31, 2011 and 2010:

PUGET ENERGY AND PUGET SOUND ENERGY DERIVATIVE PORTFOLIO (DOLLARS IN THOUSANDS)	ENERGY DERIVATIVES DECEMBER 31, 2011		DECEMBER 31, 2010	
	ASSETS	LIABILITIES	ASSETS	LIABILITIES
Electric portfolio:				
Current	$ 5,212	$ 173,582	$ 4,716	$ 142,780
Long-term	5,508	90,752	5,046	99,801
Total electric derivatives	$ 10,720	$ 264,334	$ 9,762	$ 242,581
Gas portfolio:				
Current	$ 1,435	$ 128,297	$ 2,784	$ 100,273
Long-term	4,576	78,607	3,187	55,378
Total gas derivatives	$ 6,011	$ 206,904	$ 5,971	$ 155,651
Total derivatives	$ 16,731	$ 471,238	$ 15,733	$ 398,232

For further details regarding both the fair value of derivative instruments and the impacts such instruments have on current period earnings and OCI (for cash flow hedges), see Notes 13 and 14 to the consolidated financial statements included in Item 8 of this report.

At December 31, 2011, the Company had total assets of $6.0 million and total liabilities of $206.9 million related to financial contracts used to economically hedge the cost of physical natural gas purchased to serve natural gas customers. All fair value adjustments of derivatives relating to the natural gas business have been reclassified to a deferred account in accordance with ASC 980 due to the PGA mechanism. All increases and decreases in the cost of natural gas supply are passed on to customers with the PGA mechanism. As the gains and losses on the hedges are realized in future periods, they will be recorded as natural gas costs under the PGA mechanism.

At December 31, 2011, a hypothetical 10.0% increase or decrease in market prices of natural gas and electricity would change the fair value of the Company's derivative contracts by $46.2 million, with an after-tax impact of $30.0 million.

The change in fair value of the Company's outstanding energy derivative instruments from December 31, 2010 through December 31, 2011 is summarized in the table below:

PUGET ENERGY AND PUGET SOUND ENERGY ENERGY DERIVATIVE CONTRACTS GAIN (LOSS) (DOLLARS IN THOUSANDS)	
Fair value of contracts outstanding at December 31, 2010	$ (382,499)
Contracts realized or otherwise settled during 2011	235,390
Change in fair value of derivatives	(307,398)
Fair value of contracts outstanding at December 31, 2011	$ (454,507)

The fair value of the Company's outstanding derivative instruments at December 31, 2011, based on price source and the period during which the instrument will mature, is summarized below:

PUGET ENERGY AND PUGET SOUND ENERGY SOURCE OF FAIR VALUE (DOLLARS IN THOUSANDS)	FAIR VALUE OF CONTRACTS BY SETTLEMENT YEAR 2012	2013-2014	2015-2016	THEREAFTER	TOTAL
Prices provided by external sources [1]	$ (298,087)	$ (152,885)	$ (4,166)	$ 112	$ (455,026)
Prices based on internal models and valuation methods [2]	2,855	2,408	(2,511)	(2,233)	519
Total fair value	$ (295,232)	$ (150,477)	$ (6,677)	$ (2,121)	$ (454,507)

1 *Prices provided by external pricing service, which utilizes broker quotes and pricing models.*

2 *Pricing derived from inputs with internally developed methodologies.*

CONTINGENT FEATURES AND COUNTERPARTY CREDIT RISK

PSE is exposed to credit risk primarily through buying and selling electricity and natural gas to serve customers. Credit risk is the potential loss resulting from a counterparty's non-performance under an agreement. PSE manages credit risk with policies and procedures for, among other things, counterparty analysis and measurement, monitoring and mitigation of exposure.

Where deemed appropriate, PSE may request collateral or other security from its counterparties to mitigate the potential credit default losses. Criteria employed in this decision include, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure. As of December 31, 2011, PSE held approximately $11.1 million worth of standby letters of credit in support of various electricity and REC transactions.

It is possible that volatility in energy commodity prices could cause PSE to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, PSE could suffer a material financial loss. However, as of December 31, 2011, approximately 96.0% of PSE's energy and natural gas portfolio exposure, including NPNS transactions, is with counterparties that are rated at least investment grade by the major rating agencies and 4.0% of PSE's portfolio are either rated below investment grade or are not rated by rating agencies. PSE assesses credit risk internally for counterparties that are not rated.

PSE has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. PSE generally enters into the following master arrangements: (1) WSPP, Inc. (WSPP) agreements - standardized power sales contracts in the electric industry; (2) International Swaps and Derivatives Association (ISDA) agreements - standardized financial gas and electric contracts; and (3) North American Energy Standards Board (NAESB) agreements - standardized physical gas contracts. PSE believes that entering into such agreements reduces the risk of default by allowing a counterparty the ability to make only one net payment.

PSE monitors counterparties that are experiencing financial problems, have significant swings in credit default swap rates, have credit rating changes by external rating agencies or have changes in ownership. Counterparty credit risk impacts PSE's decisions on derivative accounting treatment. A counterparty may have a deterioration of credit below investment grade, potentially indicating that it is no longer probable that it will fulfill its obligations under a contract (e.g., make a physical delivery upon the contract's maturity). ASC 815 specifies the requirements for derivative contracts to qualify for the NPNS scope exception. When performance is no longer probable, PSE records the fair value of the contract on the balance sheet with the corresponding amount recorded in the statements of income.

Accumulated OCI related to cash flow hedges is also impacted by a counterparty's deterioration of credit under ASC 815 guidelines. If a forecasted transaction associated with the cash flow hedge is probable of not occurring, PSE will reclassify the amounts deferred in accumulated OCI into earnings.

Should a counterparty file for bankruptcy, which would be considered a default under master arrangements, PSE may terminate related contracts. Derivative accounting entries previously recorded would be reversed in the financial statements. PSE would compute any terminations receivable or payable, based on the terms of existing master agreements.

The Company computes credit reserves at a master agreement level by counterparty (i.e. WSPP, ISDA or NAESB). The Company considers external credit ratings and market factors, such as credit default swaps and bond spreads, in determination of reserves. The Company recognizes that external ratings may not always reflect how a market participant perceives a counterparty's risk of default. The Company uses both default factors published by Standard & Poor's and factors derived through analysis of market risk, which reflect the application of an industry standard recovery rate. The Company selects a default factor by counterparty at an aggregate master agreement level based on a weighted-average default tenor for that counterparty's deals. The default tenor is used by weighting the fair value and contract tenors for all deals for each counterparty and coming up with an average value. The default factor used is dependent upon whether the counterparty is in a net asset or a net liability position after applying the master agreement levels.

The Company applies the counterparty's default factor to compute credit reserves for counterparties that are in a net asset position. Moreover, the Company calculates a non-performance risk on its derivative liabilities by using its estimated incremental borrowing rate over the risk-free rate. The fair value of derivatives includes the impact of taking into account credit and non-performance reserves. As of December 31, 2011, the Company was in a net liability position with the majority of its counterparties, therefore the default factors of counterparties did not have a significant impact on reserves for the year. Despite its net liability position, PSE was not required to post additional collateral with any of its counterparties. Additionally, PSE did not trigger any collateral requirements with any of its counterparties, nor were any of PSE's counterparties required to post additional collateral resulting from credit rating downgrades.

INTEREST RATE RISK

The Company believes its interest rate risk primarily relates to the use of short-term debt instruments, leases and anticipated long-term debt financing needed to fund capital requirements. The Company manages its interest rate risk through the issuance of mostly fixed-rate debt of various maturities. The Company utilizes internal cash from operations, commercial paper and credit facilities to meet short-term funding needs. Short-term obligations are commonly refinanced with fixed-rate bonds or notes when needed and when interest rates are considered favorable. The Company may enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with its debt. As of December 31, 2011, Puget Energy had four interest rate swap contracts outstanding with a total notional amount of $1.28 billion. PSE did not have any outstanding interest rate swap instruments as of December 31, 2011.

In February 2009, Puget Energy entered into the interest rate swap transactions to hedge risk associated with one-month LIBOR floating rate debt. Subsequently, in order to satisfy a commitment the Company made to the Washington Commission and to mitigate refinancing risk, the Company refinanced a portion of the underlying debt hedged by the interest rate swaps during 2010 and again during 2011. As a result of refinancing, the Company de-designated the cash flow hedge accounting relationship between the debt and interest rate swaps in 2010. All fair value gains or losses associated with the interest rate swaps subsequent to the de-designation are recorded in earnings. At December 31, 2011, the outstanding notional balance of the interest rate swaps is $1.28 billion, compared to the variable rate debt balance of only $843 million. Under the existing credit agreements, the Company may retain a portion of those swaps that are in excess of the underlying debt (not economic hedges) until June 2012 at which point the Company may decide to unwind or follow other strategies to mitigate the risk of those un-hedged swaps. During the period in which the Company's interest rate swaps are in excess of the Company's variable rate debt, the Company will be subject to additional interest rate risk. The Company has settled approximately $277 million of the interest rate swaps on February 15, 2012. The transaction did not impact the consolidated statements of income as the fair value losses for those swaps had already been recorded through earnings.

At December 31, 2011, the fair value of the interest rate swaps was a $52.4 million pre-tax loss. The fair value considers the risk of Puget Energy's non-performance by using its incremental borrowing rate on unsecured debt over the risk-free rate in the valuation estimate. The ending balance in OCI includes a loss of $22.4 million pre-tax related to the interest rate swaps designated as marked-to-market during the reporting period. The OCI balance relates to the loss that was recorded when the cash flow hedge was de-designated in December 2010.

A hypothetical 10% increase or decrease in the one-month LIBOR would change the fair value of the hedged portion of interest rate swaps by $1.2 million, or $0.8 million after tax, recorded in accumulated OCI.

As a result of the cash flow hedge de-designation related to its interest rate swaps, the Company is exposed to additional interest rate risk on the portion of swaps that remain un-hedged. A hypothetical 10% change in the one-month LIBOR would change the fair value of these specific un-hedged swaps by $0.7 million. This hypothetical change in fair value would directly impact earnings.

The following table presents Puget Energy's interest rate swaps at December 31, 2011 and 2010:

PUGET ENERGY DERIVATIVE PORTFOLIO (DOLLARS IN THOUSANDS)	DECEMBER 31, 2011		DECEMBER 31, 2010	
	ASSETS	LIABILITIES	ASSETS	LIABILITIES
Interest rate swaps:				
Current	$ --	$ 25,210	$ --	$ 30,047
Long-term	--	27,199	--	27,956
Total	$ --	$ 52,409	$ --	$ 58,003

The change in fair value of Puget Energy's outstanding interest rate swaps from December 31, 2010 through December 31, 2011 is summarized in the table below:

INTEREST RATE SWAP CONTRACTS GAIN (LOSS) (DOLLARS IN THOUSANDS)	PUGET ENERGY
Fair value of contracts outstanding at December 31, 2010	$ (58,003)
Contracts realized or otherwise settled during 2011	10,290
Change in fair value of derivatives	(4,696)
Fair value of contracts outstanding at December 31, 2011	$ (52,409)

The fair value of Puget Energy's outstanding interest rate swaps at December 31, 2011, based on price source and the period during which the instrument will mature, is summarized below:

SOURCE OF FAIR VALUE (DOLLARS IN THOUSANDS)	FAIR VALUE OF CONTRACTS BY SETTLEMENT YEAR 2012	2013-2014	2015-2016	TOTAL
Prices provided by external sources [1]	$ (25,210)	$ (27,199)	$ --	$ (52,409)

[1] *Prices provided by external pricing service, which utilizes broker quotes and pricing models. Pricing inputs are based on observable market data.*

From time to time PSE may enter into treasury locks or forward starting swap contracts to hedge interest rate exposure related to an anticipated debt issuance. The ending balance in OCI related to the forward starting swaps and previously settled treasury lock contracts at December 31, 2011 is a net loss of $6.9 million after tax and accumulated amortization. This compares to an after-tax loss of $7.3 million in OCI as of December 31, 2010. All financial hedge contracts of this type are reviewed by an officer, presented to the Asset Management Committee or the Board of Directors, as applicable and are approved prior to execution. PSE had no treasury locks or forward starting swap contracts outstanding at December 31, 2011.

The following table presents the carrying amounts and the fair value of the Company's debt instruments at December 31, 2011 and 2010:

	DECEMBER 31, 2011		DECEMBER 31, 2010	
(DOLLARS IN THOUSANDS)	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
Financial liabilities:				
Short-term debt	$ 25,000	$ 25,000	$ 247,000	$ 247,000
Short-term debt owed by PSE to Puget Energy [1]	29,998	29,998	22,598	22,598
Long-term debt – fixed-rate	4,447,511	5,752,154	3,629,660	4,226,639
Long-term debt – variable rate	829,856	829,856	1,013,053	1,083,117

[1] *Short-term debt owed by PSE to Puget Energy is eliminated upon consolidation of Puget Energy.*

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS OF PUGET ENERGY AND PUGET SOUND ENERGY:

All other schedules have been omitted because of the absence of the conditions under which they are required, or because the information required is included in the consolidated financial statements or the notes thereto.

Financial statements of PSE's subsidiaries are not filed herewith inasmuch as the assets, revenue, earnings and earnings reinvested in the business of the subsidiaries are not material in relation to those of the Company.

REPORT OF MANAGEMENT AND STATEMENT OF RESPONSIBILITY

PUGET ENERGY, INC.

AND

PUGET SOUND ENERGY, INC.

Puget Energy, Inc. and Puget Sound Energy, Inc. (the Company) management assumes accountability for maintaining compliance with our established financial accounting policies and for reporting our results with objectivity and integrity. The Company believes it is essential for investors and other users of the consolidated financial statements to have confidence that the financial information we provide is timely, complete, relevant and accurate. Management is also responsible to present fairly Puget Energy's and Puget Sound Energy's consolidated financial statements, prepared in accordance with GAAP.

Management, with oversight of the Board of Directors, established and maintains a strong ethical climate under the guidance of our Corporate Ethics and Compliance Program so that our affairs are conducted to high standards of proper personal and corporate conduct. Management also established an internal control system that provides reasonable assurance as to the integrity and accuracy of the consolidated financial statements. These policies and practices reflect corporate governance initiatives designed to ensure the integrity and independence of our financial reporting processes including:

- Our Board has adopted clear corporate governance guidelines.
- With the exception of the President and Chief Executive Officer, the Board members are independent of management.
- All members of our key Board committees – the Audit Committee, the Compensation and Leadership Development Committee and the Governance and Public Affairs Committee – are independent of management.
- The non-management members of our Board meet regularly without the presence of Puget Energy and Puget Sound Energy management.
- The Charters of our Board committees clearly establish their respective roles and responsibilities.
- The Company has adopted a Corporate Ethics and Compliance Code with a hotline (through an independent third party) available to all employees, and our Audit Committee has procedures in place for the anonymous submission of employee complaints on accounting, internal accounting controls or auditing matters. The Compliance Program is led by the Chief Ethics and Compliance Officer of the Company.
- Our internal audit control function maintains critical oversight over the key areas of our business and financial processes and controls, and reports directly to our Board Audit Committee.

Management is confident that the internal control structure is operating effectively and will allow the Company to meet the requirements under Section 404 of the Sarbanes-Oxley Act of 2002.

PricewaterhouseCoopers LLP, our independent registered public accounting firm, reports directly to the Audit Committee of the Board of Directors. PricewaterhouseCoopers LLP's accompanying report on our consolidated financial statements is based on its audit conducted in accordance with auditing standards prescribed by the Public Company Accounting Oversight Board, including a review of our internal control structure for purposes of designing their audit procedures. Our independent registered accounting firm has reported on the effectiveness of our internal control over financial reporting as required under Section 404 of the Sarbanes-Oxley Act of 2002.

We are committed to improving shareholder value and accept our fiduciary oversight responsibilities. We are dedicated to ensuring that our high standards of financial accounting and reporting as well as our underlying system of internal controls are maintained. Our culture demands integrity and we have confidence in our processes, our internal controls and our people, who are objective in their responsibilities and who operate under a high level of ethical standards.

/s/ Kimberly J. Harris	/s/ Daniel A. Doyle
Kimberly J. Harris	Daniel A. Doyle
President and Chief Executive Officer	*Senior Vice President*
	and Chief Financial Officer
	(Principal Financial and
	Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder
of Puget Energy, Inc.

In our opinion, the consolidated balance sheets and the related consolidated statements of income, comprehensive income, common shareholder's equity and cash flows present fairly, in all material respects, the financial position of Puget Energy, Inc. and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for the years then ended and for the period from February 6, 2009 through December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules of Condensed Financial Information of Puget Energy, Inc. and the schedule of Valuation and Qualifying Accounts and Reserves for the years ended December 31, 2011 and 2010 and for the period from February 6, 2009 through December 31, 2009, present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Seattle, Washington
March 5, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of Puget Energy, Inc.

In our opinion, the consolidated statements of income, comprehensive income, common shareholder’s equity and cash flows for the period January 1, 2009 to February 5, 2009 present fairly in all material respects the results of operations and cash flows of Puget Energy, Inc. and its subsidiaries (Predecessor Company) for the period from January 1, 2009 to February 5, 2009 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the schedule of Condensed Financial Information of Puget Energy, Inc. and the schedule of Valuation and Qualifying Accounts and Reserves for the period from January 1, 2009 to February 5, 2009 present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Seattle, Washington
February 25, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Puget Sound Energy, Inc.

In our opinion, the consolidated balance sheets and the related consolidated statements of income, comprehensive income, common shareholder's equity and cash flows present fairly, in all material respects, the financial position of Puget Sound Energy, Inc. and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule of Valuation and Qualifying Accounts and Reserves presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Seattle, Washington
March 5, 2012

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in Thousands)

	SUCCESSOR			PREDECESSOR
	YEAR ENDED DECEMBER 31, 2011	YEAR ENDED DECEMBER 31, 2010	FEBRUARY 6, 2009 – DECEMBER 31, 2009	JANUARY 1, 2009 – FEBRUARY 5, 2009
Operating revenue:				
Electric	$ 2,147,220	$ 2,107,469	$ 1,885,118	$ 213,618
Gas	1,168,850	1,011,531	1,034,744	190,001
Other	2,695	3,217	5,286	94
Total operating revenue	3,318,765	3,122,217	2,925,148	403,713
Operating expenses:				
Energy costs:				
Purchased electricity	771,405	773,429	796,040	90,737
Electric generation fuel	199,471	268,147	196,483	11,961
Residential exchange	(71,147)	(75,109)	(83,962)	(12,542)
Purchased gas	622,088	535,933	597,935	120,925
Unrealized (gain) loss on derivative instruments, net	11,494	54,095	(156,601)	3,867
Utility operations and maintenance	497,921	486,701	449,745	37,650
Non-utility expense and other	9,442	23,952	16,672	112
Merger and related costs	--	--	2,731	44,324
Depreciation	299,597	292,634	242,477	21,773
Amortization	72,381	71,572	63,466	4,969
Conservation amortization	107,646	90,109	58,875	7,592
Taxes other than income taxes	323,527	292,520	266,424	36,935
Total operating expenses	2,843,825	2,813,983	2,450,285	368,303
Operating income	474,940	308,234	474,863	35,410
Other income (deductions):				
Other income	58,052	45,196	49,158	3,653
Other expense	(5,380)	(5,673)	(6,154)	(369)
Non-hedged interest rate derivative expense	(28,601)	(7,955)	--	--
Charitable contributions	--	--	(5,000)	--
Interest charges:				
AFUDC	29,949	14,157	8,864	350
Interest expense	(371,910)	(321,167)	(265,675)	(17,291)
Income (loss) before income taxes	157,050	32,792	256,056	21,753
Income tax (benefit) expense	33,760	2,481	82,041	8,997
Net income (loss)	$ 123,290	$ 30,311	$ 174,015	$ 12,756

The accompanying notes are an integral part of the consolidated financial statements.

PUGET ENERGY, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in Thousands)

	SUCCESSOR			PREDECESSOR
	YEAR ENDED DECEMBER 31, 2011	YEAR ENDED DECEMBER 31, 2010	FEBRUARY 6, 2009 – DECEMBER 31, 2009	JANUARY 1, 2009 – FEBRUARY 5, 2009
Net income (loss)	$ 123,290	$ 30,311	$ 174,015	$ 12,756
Other comprehensive income (loss):				
Net unrealized gain (loss) on interest rate swaps during the period, net of tax	--	(58,175)	(22,777)	--
Reclassification of net unrealized loss on interest rate swaps during the period, net of tax	25,443	22,027	18,884	--
Net unrealized gain (loss) from pension and postretirement plans, net of tax	(54,826)	5,172	34,458	315
Net unrealized loss on energy derivative instruments during the period, net of tax	--	--	(26,222)	(24,162)
Reclassification of net unrealized loss on energy derivative instruments settled during the period, net of tax	1,545	4,420	19,144	4,509
Amortization of financing cash flow hedge contracts to earnings, net of tax	--	--	--	26
Other comprehensive income (loss)	(27,838)	(26,556)	23,487	(19,312)
Comprehensive income (loss)	$ 95,452	$ 3,755	$ 197,502	$ (6,556)

The accompanying notes are an integral part of the consolidated financial statements.

PUGET ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

ASSETS

	DECEMBER 31, 2011	DECEMBER 31, 2010
Utility plant (including construction work in progress of $1,282,463 and $628,387, respectively):		
Electric plant	$ 6,067,672	$ 5,253,786
Gas plant	2,238,741	2,129,200
Common plant	418,236	318,615
Less: Accumulated depreciation and amortization	(674,782)	(429,038)
Net utility plant	8,049,867	7,272,563
Other property and investments:		
Goodwill	1,656,513	1,656,513
Investment in exchange power contract	19,396	22,923
Other property and investments	123,352	125,918
Total other property and investments	1,799,261	1,805,354
Current assets:		
Cash and cash equivalents	37,235	36,557
Restricted cash	4,183	5,470
Accounts receivable, net of allowance for doubtful accounts of $8,495 and $9,784, respectively	336,530	327,615
Unbilled revenue	191,150	194,088
Purchased gas adjustment receivable	--	5,992
Materials and supplies, at average cost	76,068	85,413
Fuel and gas inventory, at average cost	100,491	96,633
Unrealized gain on derivative instruments	6,647	7,500
Income taxes	11,553	76,183
Prepaid expense and other	13,969	14,835
Power contract acquisition adjustment gain	65,096	134,553
Deferred income taxes	101,934	83,086
Total current assets	944,856	1,067,925
Other long-term and regulatory assets:		
Regulatory asset for deferred income taxes	62,304	73,337
Power cost adjustment mechanism	6,818	15,618
Regulatory assets related to power contracts	46,202	116,116
Other regulatory assets	766,825	814,603
Unrealized gain on derivative instruments	10,084	8,233
Power contract acquisition adjustment gain	517,740	624,667
Other	180,753	130,920
Total other long-term and regulatory assets	1,590,726	1,783,494
Total assets	$ 12,384,710	$ 11,929,336

The accompanying notes are an integral part of the consolidated financial statements.

PUGET ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

CAPITALIZATION AND LIABILITIES

	December 31, 2011	December 31, 2010
Capitalization:		
Common shareholder's equity:		
Common stock $0.01 par value, 1,000 share authorized, 200 shares outstanding	$ --	$ --
Additional paid-in capital	3,308,957	3,308,957
Earnings reinvested in the business	22,873	17,024
Accumulated other comprehensive income (loss), net of tax	(30,907)	(3,069)
Total common shareholder's equity	3,300,923	3,322,912
Long-term debt:		
First mortgage bonds and senior notes	3,362,000	2,792,000
Pollution control bonds	161,860	161,860
Junior subordinated notes	250,000	250,000
Long-term debt	1,793,000	1,490,000
Debt discount and other	(289,493)	(311,147)
Total long-term debt	5,277,367	4,382,713
Total capitalization	8,578,290	7,705,625
Current liabilities:		
Accounts payable	339,361	291,148
Short-term debt	25,000	247,000
Current maturities of long-term debt	--	260,000
Purchased gas adjustment liability	25,940	--
Accrued expenses:		
Taxes	90,727	81,505
Salaries and wages	40,892	34,453
Interest	69,329	59,182
Unrealized loss on derivative instruments	327,089	273,100
Power contract acquisition adjustment loss	8,547	69,915
Other	74,409	114,409
Total current liabilities	1,001,294	1,430,712
Long-term and regulatory liabilities:		
Deferred income taxes	1,153,755	1,127,611
Unrealized loss on derivative instruments	196,558	183,135
Regulatory liabilities	346,225	305,936
Regulatory liabilities related to power contracts	582,836	759,220
Power contract acquisition adjustment loss	37,655	46,779
Other deferred credits	488,097	370,318
Total long-term and regulatory liabilities	2,805,126	2,792,999
Commitments and contingencies (Note 19)		
Total capitalization and liabilities	$ 12,384,710	$ 11,929,336

The accompanying notes are an integral part of the consolidated financial statements.

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(Dollars in Thousands)

	Common Stock					
	Shares	Amount	Additional Paid-in Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)	Total Equity
Predecessor						
Balance at December 31, 2008	129,678,489	$ 1,297	$ 2,275,225	$ 259,483	$ (262,804)	$ 2,273,201
Net income	--	--	--	12,756	--	12,756
Common stock dividend	--	--	--	(38,188)	--	(38,188)
Common stock expense	--	--	(455)	--	--	(455)
Vesting of employee common stock	--	--	1,531	--	--	1,531
Other comprehensive loss	--	--	--	--	(19,312)	(19,312)
Balance at February 5, 2009	129,678,489	$ 1,297	$ 2,276,301	$ 234,051	$ (282,116)	$ 2,229,533
Successor						
Capitalization at merger	200	$ --	$ 3,308,529	$ --	$ --	$ 3,308,529
Net income	--	--	--	174,015	--	174,015
Common stock dividend	--	--	--	(82,991)	--	(82,991)
Employee stock plan tax windfall	--	--	428	--	--	428
Other comprehensive income	--	--	--	--	23,487	23,487
Balance at December 31, 2009	200	$ --	$ 3,308,957	$ 91,024	$ 23,487	$ 3,423,468
Net income	--	--	--	30,311	--	30,311
Common stock dividend	--	--	--	(104,311)	--	(104,311)
Other comprehensive income	--	--	--	--	(26,556)	(26,556)
Balance at December 31, 2010	200	$ --	$ 3,308,957	$ 17,024	$ (3,069)	$ 3,322,912
Net income	--	--	--	123,290	--	123,290
Common stock dividend	--	--	--	(117,441)	--	(117,441)
Other comprehensive income	--	--	--	--	(27,838)	(27,838)
Balance at December 31, 2011	200	$ --	$ 3,308,957	$ 22,873	$ (30,907)	$ 3,300,923

The accompanying notes are an integral part of the consolidated financial statements.

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

			Successor	Predecessor
	Year Ended December 31, 2011	Year Ended December 31, 2010	February 6, 2009 – December 31, 2009	January 1, 2009 – February 5, 2009
Operating activities:				
Net income (loss)	$ 123,290	$ 30,311	$ 174,015	$ 12,756
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation	299,597	292,634	242,477	21,773
Amortization	72,381	71,572	63,466	4,969
Conservation amortization	107,646	90,109	58,875	7,592
Deferred income taxes and tax credits, net	33,318	(32,955)	244,216	(512)
Net unrealized (gain) loss on derivative instruments	45,043	50,495	(156,601)	3,867
Derivative contracts classified as financing activities due to merger	182,710	371,621	524,397	--
AFUDC - equity	(32,431)	(12,677)	(4,108)	(69)
Pension funding	(5,000)	(12,000)	(18,400)	--
Regulatory assets	26,631	26,198	(5,276)	(1,668)
Regulatory liabilities	21,031	28,821	18,436	(126)
Other long-term assets	(59,094)	(50,009)	(17,963)	2,845
Other long-term liabilities	46,473	31,944	(12,536)	1,141
Change in certain current assets and liabilities:				
Accounts receivable and unbilled revenue	(5,977)	7,261	91,515	(31,332)
Materials and supplies	8,154	(19,378)	808	(3,388)
Fuel and gas inventory	(4,852)	3,591	16,786	7,605
Income taxes	64,630	58,434	(133,773)	18,277
Prepayments and other	605	(2,345)	5,745	(3,295)
Purchased gas adjustment	31,932	(55,579)	38,984	1,711
Accounts payable	1,098	(26,396)	(85,073)	(40,203)
Taxes payable	9,222	4,203	4,949	(3,340)
Accrued expenses and other	43,921	10,094	(40,369)	59,172
Net cash provided by operating activities	1,010,328	865,949	1,010,570	57,775
Investing activities:				
Construction expenditures – excluding equity AFUDC	(976,513)	(859,091)	(726,157)	(49,531)
Energy efficiency expenditures	(94,405)	(95,726)	(82,258)	(4,918)
Treasury grant payment received	--	28,675	--	--
Restricted cash	1,287	14,374	(945)	(10)
Other	(7,184)	6,001	26,284	959
Net cash used in investing activities	(1,076,815)	(905,767)	(783,076)	(53,500)
Financing activities:				
Change in short-term debt and leases, net	(227,651)	141,941	38,807	(151,800)
Dividends paid	(117,441)	(104,311)	(121,179)	--
Long-term notes and bonds issued	1,382,000	1,025,000	400,211	250,000
Redemption of preferred stock	--	--	--	(1,889)
Redemption of bonds and notes	(769,000)	(675,000)	(158,000)	--
Derivative contracts classified as financing activities due to merger	(182,710)	(371,621)	(524,397)	--
Issuance cost of bonds and other	(18,033)	(18,161)	(16,372)	7,133
Net cash provided by (used in) financing activities	67,165	(2,152)	(380,930)	103,444
Net increase (decrease) in cash and cash equivalents	678	(41,970)	(153,436)	107,719
Cash and cash equivalents at beginning of period	36,557	78,527	231,963	38,526
Cash and cash equivalents at end of period	$ 37,235	$ 36,557	$ 78,527	$ 146,245
Supplemental cash flow information:				
Cash payments for interest (net of capitalized interest)	$ 280,847	$ 278,926	$ 247,247	$ 1,239
Cash payments (refunds) for income taxes	(64,016)	(22,243)	(47,740)	--

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.

CONSOLIDATED STATEMENTS OF INCOME

(Dollars in Thousands)

	YEAR ENDED DECEMBER 31,		
	2011	2010	2009
Operating revenue:			
Electric	$ 2,147,220	$ 2,107,469	$ 2,098,736
Gas	1,168,850	1,011,531	1,224,745
Other	3,733	3,217	5,020
Total operating revenue	3,319,803	3,122,217	3,328,501
Operating expenses:			
Energy costs:			
Purchased electricity	771,983	774,007	887,306
Electric generation fuel	199,471	268,147	208,444
Residential exchange	(71,147)	(75,109)	(96,504)
Purchased gas	622,088	535,933	718,860
Unrealized (gain) loss on derivative instruments, net	54,146	166,953	(1,254)
Utility operations and maintenance	497,921	486,701	487,396
Non-utility expense and other	11,147	11,159	14,532
Merger and related costs	--	--	23,908
Depreciation	299,597	292,634	269,386
Amortization	72,381	71,572	63,466
Conservation amortization	107,646	90,109	66,466
Taxes other than income taxes	323,527	292,520	303,360
Total operating expenses	2,888,760	2,914,626	2,945,366
Operating income (loss)	431,043	207,591	383,135
Other income (deductions):			
Other income	58,041	45,153	52,812
Other expense	(5,380)	(5,673)	(6,524)
Interest charges:			
AFUDC	29,949	14,157	9,215
Interest expense	(231,212)	(234,793)	(211,478)
Interest expense on parent note	(204)	(218)	(264)
Income (loss) before income taxes	282,237	26,217	226,896
Income tax (benefit) expense	78,117	122	67,644
Net income (loss)	$ 204,120	$ 26,095	$ 159,252

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in Thousands)

	YEAR ENDED DECEMBER 31,		
	2011	2010	2009
Net income (loss)	$ 204,120	$ 26,095	$ 159,252
Other comprehensive income (loss):			
Net unrealized gain (loss) from pension and postretirement plans, net of tax	(52,927)	3,610	23,807
Net unrealized gain (loss) on energy derivative instruments during the period, net of tax	--	--	(61,277)
Reclassification of net unrealized loss on energy derivative instruments settled during the period, net of tax	21,678	48,546	89,837
Amortization of financing cash flow hedge contracts to earnings, net of tax	317	317	317
Other comprehensive income (loss)	(30,932)	52,473	52,684
Comprehensive income (loss)	$ 173,188	$ 78,568	$ 211,936

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

ASSETS

	DECEMBER 31, 2011	DECEMBER 31, 2010
Utility plant (including construction work in progress of $1,282,463 and $628,387, respectively):		
Electric plant	$ 8,390,667	$ 7,586,208
Gas plant	2,855,794	2,752,962
Common plant	518,318	427,227
Less: Accumulated depreciation and amortization	(3,714,912)	(3,509,277)
Net utility plant	8,049,867	7,257,120
Other property and investments:		
Investment in exchange power contract	19,396	22,923
Other property and investments	113,528	115,056
Total other property and investments	132,924	137,979
Current assets:		
Cash and cash equivalents	31,010	36,320
Restricted cash	4,183	5,470
Accounts receivable, net of allowance for doubtful accounts of $8,495 and $9,784, respectively	336,483	327,341
Unbilled revenue	191,150	194,088
Purchased gas adjustment receivable	--	5,992
Materials and supplies, at average cost	76,068	84,222
Fuel and gas inventory, at average cost	97,074	92,222
Unrealized gain on derivative instruments	6,647	7,500
Income taxes	11,553	62,114
Prepaid expenses and other	13,807	14,412
Deferred income taxes	112,204	80,215
Total current assets	880,179	909,896
Other long-term and regulatory assets:		
Regulatory asset for deferred income taxes	61,344	73,337
Power cost adjustment mechanism	6,818	15,618
Other regulatory assets	760,585	769,744
Unrealized gain on derivative instruments	10,084	8,233
Other	183,746	138,857
Total other long-term and regulatory assets	1,022,577	1,005,789
Total assets	$ 10,085,547	$ 9,310,784

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

CAPITALIZATION AND LIABILITIES

	DECEMBER 31, 2011	DECEMBER 31, 2010
Capitalization:		
Common shareholder’s equity:		
Common stock $0.01 par value – 150,000,000 shares authorized, 85,903,791 shares outstanding	$ 859	$ 859
Additional paid-in capital	3,246,205	2,959,205
Earnings reinvested in the business	163,735	172,490
Accumulated other comprehensive income (loss), net of tax	(188,579)	(157,647)
Total common shareholder’s equity	3,222,220	2,974,907
Long-term debt:		
First mortgage bonds and senior notes	3,362,000	2,792,000
Pollution control bonds	161,860	161,860
Junior subordinated notes	250,000	250,000
Debt discount and other	(15)	--
Total long-term debt	3,773,845	3,203,860
Total capitalization	6,996,065	6,178,767
Current liabilities:		
Accounts payable	339,568	291,765
Short-term debt	25,000	247,000
Short-term note owed to parent	29,998	22,598
Current maturities of long-term debt	--	260,000
Purchased gas adjustment liability	25,940	--
Accrued expenses:		
Taxes	90,727	81,505
Salaries and wages	40,892	34,453
Interest	55,843	54,723
Unrealized loss on derivative instruments	301,879	243,053
Other	68,346	49,661
Total current liabilities	978,193	1,284,758
Long-term and regulatory liabilities:		
Deferred income taxes	1,115,639	1,034,517
Unrealized loss on derivative instruments	169,359	155,179
Regulatory liabilities	340,907	296,884
Other deferred credits	485,384	360,679
Total long-term and regulatory liabilities	2,111,289	1,847,259
Commitments and contingencies (Note 19)		
Total capitalization and liabilities	$ 10,085,547	$ 9,310,784

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(Dollars in Thousands)

	Common Stock					
	Shares	Amount	Additional Paid-in Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)	Total Equity
Balance at December 31, 2008	85,903,791	$ 859,038	$ 1,296,005	$ 356,947	$ (262,804)	$ 2,249,186
Change in par value	--	(858,179)	858,179	--	--	--
Net income	--	--	--	159,252	--	159,252
Common stock dividend	--	--	--	(183,071)	--	(183,071)
Investment from parent	--	--	805,283	--	--	805,283
Employee common stock award transferred to liability award	--	--	(690)	--	--	(690)
Employee stock plan tax windfall	--	--	428	--	--	428
Other comprehensive income	--	--	--	--	52,684	52,684
Balance at December 31, 2009	85,903,791	$ 859	$ 2,959,205	$ 333,128	$ (210,120)	$ 3,083,072
Net income	--	--	--	26,095	--	26,095
Common stock dividend	--	--	--	(186,733)	--	(186,733)
Other comprehensive income	--	--	--	--	52,473	52,473
Balance at December 31, 2010	85,903,791	$ 859	$ 2,959,205	$ 172,490	$ (157,647)	$ 2,974,907
Net income	--	--	--	204,120	--	204,120
Common stock dividend	--	--	--	(212,875)	--	(212,875)
Capital Contribution	--	--	287,000	--	--	287,000
Other comprehensive income	--	--	--	--	(30,932)	(30,932)
Balance at December 31, 2011	85,903,791	$ 859	$ 3,246,205	$ 163,735	$ (188,579)	$ 3,222,220

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	YEAR ENDED DECEMBER 31,		
	2011	2010	2009
Operating activities:			
Net income (loss)	$ 204,120	$ 26,095	$ 159,252
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation	299,597	292,634	269,386
Amortization	72,381	71,572	63,466
Conservation amortization	107,646	90,109	66,466
Deferred income taxes and tax credits, net	77,757	(16,284)	194,494
Net unrealized (gain) loss on derivative instruments	54,146	166,953	(1,254)
AFUDC - equity	(32,431)	(12,677)	(4,177)
Pension funding	(5,000)	(12,000)	(18,400)
Regulatory assets	26,631	26,198	(5,821)
Regulatory liabilities	21,031	28,821	18,327
Other long-term assets	(60,046)	(48,258)	(13,757)
Other long-term liabilities	28,818	1,701	(19,003)
Change in certain current assets and liabilities:			
Accounts receivable and unbilled revenue	(6,204)	7,584	64,349
Materials and supplies	8,154	(19,618)	(2,580)
Fuel and gas inventory	(4,852)	3,591	24,391
Income taxes	50,561	37,834	(82,630)
Prepayments and other	605	(2,345)	2,353
Purchased gas adjustment	31,932	(55,579)	40,695
Accounts payable	688	(25,780)	(35,205)
Taxes payable	9,222	4,203	(7,339)
Accrued expenses and other	18,666	11,021	7,678
Net cash provided by operating activities	903,422	575,775	720,691
Investing activities:			
Construction expenditures – excluding equity AFUDC	(976,513)	(859,091)	(775,688)
Energy efficiency expenditures	(94,405)	(95,726)	(87,176)
Treasury grant payment received	--	28,675	--
Restricted cash	1,287	14,374	(955)
Other	9,043	6,001	27,249
Net cash used in investing activities	(1,060,588)	(905,767)	(836,570)
Financing activities:			
Change in short-term debt and leases, net	(227,651)	141,941	(113,286)
Dividends paid	(212,875)	(186,733)	(183,071)
Long-term notes and bonds issued	595,000	575,000	600,000
Loan from (payment to) parent	7,400	(300)	(3,156)
Redemption of preferred stock	--	--	(1,889)
Redemption of bonds and notes	(285,000)	(232,000)	(158,000)
Investment from parent	287,000	--	25,960
Issuance cost of bonds and other	(12,018)	(10,003)	(10,742)
Net cash provided by (used in) financing activities	151,856	287,905	155,816
Net increase (decrease) in cash and cash equivalents	(5,310)	(42,087)	39,937
Cash and cash equivalents at beginning of period	36,320	78,407	38,470
Cash and cash equivalents at end of period	$ 31,010	$ 36,320	$ 78,407
Supplemental cash flow information:			
Cash payments for interest (net of capitalized interest)	$ 191,666	$ 198,496	$ 183,652
Cash payments (refunds) for income taxes	(50,022)	(20,632)	(44,365)

The accompanying notes are an integral part of the consolidated financial statements.

(1) Summary of Significant Accounting Policies

BASIS OF PRESENTATION

Puget Energy, Inc. (Puget Energy) is an energy services holding company that owns Puget Sound Energy, Inc. (PSE). PSE is a public utility incorporated in the state of Washington that furnishes electric and natural gas services in a territory covering 6,000 square miles, primarily in the Puget Sound region. On February 6, 2009, Puget Holdings LLC (Puget Holdings), a consortium of long-term infrastructure investors, completed its merger with Puget Energy. As a result of the merger, all of Puget Energy's common stock is indirectly owned by Puget Holdings. The acquisition of Puget Energy was accounted for in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 805, "Business Combinations" (ASC 805), as of the date of the merger. ASC 805 requires the acquirer to recognize and measure identifiable assets acquired and liabilities assumed at fair value as of the merger date. Puget Energy's consolidated financial statements and accompanying footnotes have been segregated to present pre-merger activity as the "Predecessor" Company and post-merger activity as the "Successor" Company.

The consolidated financial statements of Puget Energy reflect the accounts of Puget Energy and its subsidiary, PSE. PSE's consolidated financial statements include the accounts of PSE and its subsidiaries. Puget Energy and PSE are collectively referred to herein as "the Company." The consolidated financial statements are presented after elimination of all significant intercompany items and transactions. PSE's consolidated financial statements continue to be accounted for on a historical basis and PSE's financial statements do not include any ASC 805 purchase accounting adjustments. The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

Certain prior year amounts have been reclassified to conform to the current year presentation.

UTILITY PLANT

PSE capitalizes, at original cost, additions to utility plant, including renewals and betterments. Costs include indirect costs such as engineering, supervision, certain taxes, pension and other employee benefits and an Allowance For Funds Used During Construction (AFUDC). Replacements of minor items of property and major maintenance are included in maintenance expense when the utility plant is retired and removed from service, the original cost of the property is charged to accumulated depreciation and costs associated with removal of the property, less salvage, are charged to the cost of removal regulatory liability.

Puget Energy remeasured the carrying amount of utility plant to fair value on February 6, 2009, as a result of purchase accounting adjustments. After February 6, 2009, Puget Energy follows the same capitalization policy for utility plan additions as PSE.

NON-UTILITY PROPERTY, PLANT AND EQUIPMENT

For PSE, the costs of other property, plant and equipment are stated at historical cost. Expenditures for refurbishment and improvements that significantly add to productive capacity or extend useful life of an asset are capitalized. Replacement of minor items is expensed on a current basis. Gains and losses on assets sold or retired are reflected in earnings.

For Puget Energy, the carrying amount of non-utility property, plant and equipment was remeasured to fair value on February 6, 2009, as a result of purchase accounting adjustments. After February 6, 2009, Puget Energy follows the same capitalization policy for non-utility property, plant and equipment as PSE.

DEPRECIATION AND AMORTIZATION

For financial statement purposes, the Company provides for depreciation and amortization on a straight-line basis. Amortization is recorded for intangibles such as regulatory assets and liabilities, computer software and franchises. The depreciation of automobiles, trucks, power-operated equipment, tools and office equipment is allocated to asset and expense accounts based on usage. The annual depreciation provision stated as a percent of a depreciable electric utility plant was 2.7%, 2.7% and 2.6% in 2011, 2010 and 2009, respectively; depreciable gas utility plant was 3.5%, 3.6% and 3.6% in 2011, 2010 and 2009, respectively; and depreciable common utility plant was 11.3%, 11.8% and 9.6% in 2011, 2010 and 2009, respectively. Depreciation on other property, plant and equipment is calculated primarily on a straight-line basis over the useful lives of the assets. The cost of removal is collected from PSE's customers through depreciation expense and any excess is recorded as a regulatory liability.

GOODWILL

On February 6, 2009, Puget Holdings completed its merger with Puget Energy. Puget Energy remeasured the carrying amount of all its assets and liabilities to fair value, which resulted in recognition of approximately $1.7 billion in goodwill. ASC 350, "Intangibles - Goodwill and Other" (ASC 350), requires that goodwill be tested for impairment at the reporting unit level on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. These events or circumstances could include a significant change in the Company's business or regulatory outlook, legal factors, a sale or disposition of a significant portion of a reporting unit or significant changes in the financial markets which could influence the Company's access to capital and interest rates. Application of the goodwill impairment test requires judgment, including the identification of reporting units, assignment of assets and liabilities to reporting units, assignment of goodwill to reporting units and the determination of the fair value of the reporting units. Management has determined Puget Energy has only one reporting unit.

The goodwill recorded by Puget Energy represents the potential long-term return to the Company's investors. Goodwill is tested for impairment annually using a two-step process. The first step compares the carrying amount of the reporting unit with its fair value, with a carrying value higher than fair value indicating potential impairment. If the first step test fails, the second step is performed. This would entail a full valuation of Puget Energy's assets and liabilities and comparing the valuation to its carrying amounts, with the aggregate difference indicating the amount of impairment. Goodwill of a reporting unit is required to be tested for impairment on an interim basis if an event occurs or circumstances change that would cause the fair value of a reporting unit to fall below its carrying amount.

Puget Energy conducted its annual impairment test in 2011 using an October 1, 2011 measurement date. The fair value of Puget Energy's reporting unit was estimated using both discounted cash flow and market approach. Such approaches are considered methodologies that market participants would use. This analysis requires significant judgments, including estimation of future cash flows, which is dependent on internal forecasts, estimation of long-term rate of growth for Puget Energy business, estimation of the useful life over which cash flows will occur, the selection of utility holding companies determined to be comparable to Puget Energy and determination of an appropriate weighted-average cost of capital or discount rate. The market approach estimates the fair value of the business based on market prices of stocks of comparable companies engaged in the same or similar lines of business. In addition, indications of market value are estimated by deriving multiples of equity or invested capital to various measures of revenue, earnings or cash flow. Changes in these estimates and or assumptions could materially affect the determination of fair value and goodwill impairment of the reporting unit. Based on the test performed, management has determined that there was no indication of impairment of Puget Energy's goodwill as of October 1, 2011. There were no events or circumstances from the date of the assessment through December 31, 2011 that would impact management's conclusion.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents consist of demand bank deposits and short-term highly liquid investments with original maturities of three months or less at the time of purchase. The cash and cash equivalents balance at Puget Energy was $37.2 million and $36.6 million as of December 31, 2011 and 2010, respectively. The 2011 and 2010 balance consisted of cash equivalents, which are reported at cost and approximates fair value, and were $16.8 million and $20.6 million, respectively.

RESTRICTED CASH

Restricted cash represents cash to be used for specific purposes. The restricted cash balance was $4.2 million and $5.5 million at December 31, 2011 and 2010, respectively. The restricted cash included $0.7 million, in both 2011 and 2010, which represents funds held by Puget Western, Inc., a PSE subsidiary, for a real estate development project. As of December 31, 2011, other restricted cash includes $2.0 million in a Benefit Protection Trust and $1.5 million in other restricted cash accounts.

MATERIALS AND SUPPLIES

Materials and supplies are used primarily in the operation and maintenance of electric and natural gas distribution and transmission systems as well as spare parts for combustion turbines used for the generation of electricity. PSE records these items at weighted-average cost.

Puget Energy remeasured the carrying amount of materials and supplies to fair value on February 6, 2009, as a result of purchase accounting adjustments. After February 6, 2009, Puget Energy follows the same policy for recording materials and supplies as PSE.

FUEL AND GAS INVENTORY

Fuel and gas inventory is used in the generation of electricity and for future sales to the Company's natural gas customers. Fuel inventory consists of coal, diesel and natural gas used for generation. Gas inventory consists of natural gas and liquefied natural gas (LNG) held in storage for future sales. PSE records these items at the lower of cost or market value using the weighted-average cost method.

For Puget Energy, the carrying amount of fuel and gas inventory was remeasured to fair value on February 6, 2009, as a result of purchase accounting adjustments. After February 6, 2009, Puget Energy follows the same policy for recording additional inventory as PSE.

REGULATORY ASSETS AND LIABILITIES

PSE accounts for its regulated operations in accordance with ASC 980 "Regulated Operations" (ASC 980). ASC 980 requires PSE to defer certain costs that would otherwise be charged to expense, if it were probable that future rates will permit recovery of such costs. It similarly requires deferral of revenues or gains and losses that are expected to be returned to customers in the future. Accounting under ASC 980 is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. In most cases, PSE classifies regulatory assets and liabilities as long-term assets or liabilities. The exception is the Purchased Gas Adjustment (PGA) which can be a current asset or current liability.

Below is a chart with the allowed return on the net regulatory assets and liabilities and the associated time periods:

PERIOD	RATE OF RETURN	AFTER-TAX RETURN
April 8, 2010 - present	8.10%	6.90%
November 1, 2008 - April 7, 2010	8.25	7.00

The net regulatory assets and liabilities at December 31, 2011 and 2010 included the following:

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	REMAINING AMORTIZATION PERIOD	DECEMBER 31, 2011	DECEMBER 31, 2010
PGA deferral of unrealized losses on derivative instruments	(a)	$ 200,893	$ 149,681
Chelan PUD contract initiation	20 years	140,580	133,888
Storm damage costs electric	2 to 7 years (a)	87,303	103,630
Environmental remediation	(a)	65,167	62,240
Baker Dam licensing operating and maintenance costs	47 years	63,272	63,459
Deferred income taxes	(a)	61,344	73,337
Deferred Washington Commission AFUDC	Varies up to 26 years	56,315	53,378
Energy conservation costs	1 to 2 years	35,111	48,367
Unamortized loss on reacquired debt	1 to 40 years	33,023	18,304
White River relicensing and other costs	(a)	30,993	32,260
Mint Farm ownership and operating costs	13.3 years	26,582	29,364
Investment in Bonneville Exchange power contract	5.5 years	19,396	22,923
PCA mechanism	(a)	6,818	15,618
PURPA electric energy supply contract buyout costs	N/A	--	40,629
PGA receivable	N/A	--	5,992
Various other regulatory assets	Varies	21,346	34,544
Total PSE regulatory assets		$ 848,143	$ 887,614
Cost of removal	(b)	$ (219,087)	$ (193,765)
Production tax credits	(c)	(93,618)	(20,186)
PGA payable	1 year	(25,940)	--
Summit purchase option buy-out	9 years	(13,913)	(15,488)
Deferred credit on gas pipeline capacity	Varies up to 6.8 years	(7,987)	(13,310)
Renewable energy credits	(a)	(2,780)	(48,493)
Various other regulatory liabilities	Up to 4.5 years	(3,522)	(5,642)
Total PSE regulatory liabilities		$ (366,847)	$ (296,884)
PSE net regulatory assets and liabilities		$ 481,296	$ 590,730

(a) *Amortization periods vary depending on timing of underlying transactions or awaiting regulatory approval in a future Washington Utilities and Transportation Commission (Washington Commission) rate proceeding.*

(b) *The balance is dependent upon the cost of removal of underlying assets and the life of utility plant.*

(c) *Amortization will begin once PTCs are utilized by PSE on its tax return.*

PUGET ENERGY (DOLLARS IN THOUSANDS)	REMAINING AMORTIZATION PERIOD	DECEMBER 31, 2011	DECEMBER 31, 2010
Total PSE regulatory assets	(a)	$ 848,143	$ 887,614
Puget Energy acquisition adjustments:			
Regulatory assets related to power contracts	1 year to 26 years	46,202	116,116
Service provider contracts	1 to 2 years	5,751	15,933
Various other regulatory assets	Varies	1,449	28,926
Total Puget Energy regulatory assets		$ 901,545	$ 1,048,589
Total PSE regulatory liabilities	(a)	$ (366,847)	$ (296,884)
Puget Energy acquisition adjustments:			
Regulatory liabilities related to power contracts	1 to 41 years	(582,836)	(759,220)
Various other regulatory liabilities	Varies	(5,318)	(9,052)
Total Puget Energy regulatory liabilities		$ (955,001)	$ (1,065,156)
Puget Energy net regulatory asset and liabilities		$ (53,456)	$ (16,567)

(a) *Puget Energy's regulatory assets and liabilities include purchase accounting adjustments as a result of the merger. For additional information, see Note 3.*

If the Company determines that it no longer meets the criteria for continued application of ASC 980, the Company would be required to write off its regulatory assets and liabilities related to those operations not meeting ASC 980 requirements. Discontinuation of ASC 980 could have a material impact on the Company's financial statements.

In accordance with guidance provided by ASC 410, "Asset Retirement and Environmental Obligations," PSE reclassified from accumulated depreciation to a regulatory liability $219.1 million and $193.8 million in 2011 and 2010, respectively, for the cost of removal of utility plant. These amounts are collected from PSE's customers through depreciation rates.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. The amount of AFUDC recorded in each accounting period varies depending principally upon the level of construction work in progress and the AFUDC rate used. AFUDC is capitalized as a part of the cost of utility plant and is credited to interest expense and as a non-cash item to other income. Cash inflow related to AFUDC does not occur until these charges are reflected in rates.

The authorized AFUDC rates authorized by the Washington Utilities and Transportation Commission (Washington Commission) for natural gas and electric utility plant additions based on the effective dates is as follows:

EFFECTIVE DATE	WASHINGTON COMMISSION AFUDC RATES
April 8, 2010 - present	8.10%
November 1, 2008 - April 7, 2010	8.25

The Washington Commission authorized the Company to calculate AFUDC using its allowed rate of return. To the extent amounts calculated using this rate exceed the AFUDC calculated rate using the Federal Energy Regulatory Commission (FERC) formula, PSE capitalizes the excess as a deferred asset, crediting other income. The deferred asset is being amortized over the average useful life of PSE's non-project electric utility plant which is approximately 30 years.

The following table presents the AFUDC amounts:

	YEAR ENDED DECEMBER 31,		
(DOLLARS IN THOUSANDS)	2011	2010	2009
Equity AFUDC	$ 32,431	$ 12,677	$ 4,177
Washington Commission AFUDC	5,108	3,715	10,693
Total in other income	37,539	16,392	14,870
Debt AFUDC	29,949	14,157	9,214
Total AFUDC	$ 67,488	$ 30,549	$ 24,084

REVENUE RECOGNITION

Operating utility revenue is recognized when the basis of services is rendered, which includes estimated unbilled revenue, in accordance with ASC 605, "Revenue Recognition" (ASC 605). Sales to other utilities are recognized in accordance with ASC 605 and ASC 815, "Derivatives and Hedging" (ASC 815). Non-utility subsidiaries recognize revenue when services are performed or upon the sale of assets. Revenue from retail sales is billed based on tariff rates approved by the Washington Commission. Sales of RECs are deferred as a regulatory liability.

PSE collected Washington state excise taxes (which are a component of general retail rates) and municipal taxes totaling $252.5 million, $231.1 million and $247.8 million for 2011, 2010 and 2009, respectively. The Company's policy is to report such taxes on a gross basis in operating revenue and taxes other than income taxes in the accompanying consolidated statements of income.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

Allowance for doubtful accounts are provided for electric and natural gas customer accounts based upon a historical experience rate of write-offs of energy accounts receivable as compared to operating revenue. The allowance account is adjusted monthly for this experience rate. Other non-energy receivable balances are reserved in the allowance account based on facts and circumstances surrounding the receivable including, among other things, collection trends, prevailing and anticipated economic conditions and specific customer credit risk, indicating some or all of the balance is uncollectible. The allowance account is maintained until either receipt of payment or the likelihood of collection is considered remote at which time the allowance account and corresponding receivable balance are written off.

The Company's allowance for doubtful accounts at December 31, 2011 and 2010 was $8.5 million and $9.8 million, respectively.

Self-Insurance

PSE currently has no insurance coverage for storm damage and recent environmental contamination occurring on PSE-owned property. PSE is self-insured for a portion of the risk associated with comprehensive liability, workers' compensation claims and catastrophic property losses other than those which are storm related. The Washington Commission has approved the deferral of certain uninsured qualifying storm damage costs that exceed $8.0 million which will be requested for collection in future rates. Additionally, costs may only be deferred if the outage meets the Institute of Electrical and Electronics Engineers (IEEE) outage criteria for system average interruption duration index.

Federal Income Taxes

For presentation in Puget Energy and PSE's separate financial statements, income taxes are allocated to the subsidiaries on the basis of separate company computations of tax, modified by allocating certain consolidated group limitations which are attributed to the separate company. Taxes payable or receivable are settled with Puget Holdings.

Rate Adjustment Mechanisms

PSE has a Power Cost Adjustment (PCA) mechanism that provides for a rate adjustment process if PSE's costs to provide customers' electricity varies from a baseline power cost rate established in a rate proceeding. All significant variable power supply cost drivers are included in the PCA mechanism (hydroelectric generation variability, market price variability for purchased power and surplus power sales, natural gas and coal fuel price variability, generation unit forced outage risk and wheeling cost variability). The PCA mechanism apportions increases or decreases in power costs, on a graduated scale, between PSE and its customers. Any unrealized gains and losses from derivative instruments accounted for under ASC 815, are deferred in proportion to the cost-sharing arrangement under the PCA mechanism. On January 10, 2007, the Washington Commission approved the PCA mechanism with the same annual graduated scale but without a cap on excess power costs.

The graduated scale is as follows:

Annual Power Cost Variability	Customers' Share	Company's Share
+/- $20 million	0%	100%
+/- $20 million - $40 million	50%	50%
+/- $40 million - $120 million	90%	10%
+/- $120 + million	95%	5%

For the years ended December 31, 2011, 2010 and 2009, the annual power cost variability was between $20.0 million and $40.0 million. Accordingly, PSE and the customer shared the costs in excess of $20.0 million in equal proportion.

The differences between the actual cost of PSE's natural gas supplies and natural gas transportation contracts and costs currently allowed by the Washington Commission are deferred and recovered or repaid through the PGA mechanism. The PGA mechanism allows PSE to recover expected natural gas and transportation costs, and defer, as a receivable or liability, any gas costs that exceed or fall short of this expected gas cost amount in the PGA mechanism rates, including interest.

Natural Gas Off-System Sales and Capacity Release

PSE contracts for firm natural gas supplies and holds firm transportation and storage capacity sufficient to meet the expected peak winter demand for natural gas by its firm customers. Due to the variability in weather, winter peaking consumption of natural gas by most of its customers and other factors, PSE holds contractual rights to natural gas supplies and transportation and storage capacity in excess of its average annual requirements to serve firm customers on its distribution system. For much of the year, there is excess capacity available for third-party natural gas sales, exchanges and capacity releases. PSE sells excess natural gas supplies, enters into natural gas supply exchanges with third parties outside of its distribution area and releases to third parties excess interstate natural gas pipeline capacity and natural gas storage rights on a short-term basis to mitigate the costs of firm transportation and storage capacity for its core natural gas customers. The proceeds from such activities, net of transactional costs, are accounted for as reductions in the cost of purchased natural gas and passed on to customers through the PGA mechanism, with no direct impact on net income. As a result, PSE nets the sales revenue and associated cost of sales for these transactions in purchased natural gas.

NON-CORE GAS SALES

As part of the Company's electric operations, PSE provides natural gas to its gas-fired generation facilities. The projected volume of natural gas for power is relative to the price of natural gas. Based on the market prices for natural gas, PSE may use the gas it has already purchased to generate power or PSE may sell the already purchased natural gas. The net proceeds from selling natural gas for power are accounted for in other electric operating revenue and are included in the PCA mechanism.

PRODUCTION TAX CREDIT

Production Tax Credits (PTCs) represent federal income tax incentives available to companies that generate energy from qualifying renewable sources. Prior to July 1, 2010, PTCs that were generated were passed-through to customers in retail sales. After July 1, 2010, PTCs which are generated and owed to customers are recorded as a regulatory liability with a corresponding reduction in electric operating revenue until PSE utilizes the tax credit on its tax return, at which time the PTCs will be credited to customers in retail sales.

ACCOUNTING FOR DERIVATIVES

ASC 815 requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value unless the contracts qualify for an exception. PSE enters into derivative contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts and swaps. Some of PSE's physical electric supply contracts qualify for the Normal Purchase Normal Sale (NPNS) exception to derivative accounting rules. PSE may enter into financial fixed contracts to economically hedge the variability of certain index-based contracts. Those contracts that do not meet the NPNS exception are marked-to-market to current earnings in the statements of income, subject to deferral under ASC 980, for energy related derivatives due to the PCA mechanism and PGA mechanism.

On July 1, 2009, Puget Energy and PSE elected to de-designate all energy related derivative contracts previously recorded as cash flow hedges for the purpose of simplifying its financial reporting. The contracts that were de-designated related to physical electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and for contracts initiated after such date, all mark-to-market adjustments are recognized through earnings. The amount previously recorded in accumulated other comprehensive income (OCI) is transferred to earnings in the same period or periods during which the hedged transaction affects earnings or sooner if management determines that the forecasted transaction is probable of not occurring. As a result, the Company will continue to experience the earnings impact of these reversals from OCI in future periods.

The Company may enter into swap instruments or other financial derivative instruments to manage the interest rate risk associated with its long-term debt financing and debt instruments. As of December 31, 2011, Puget Energy has interest rate swap contracts outstanding related to its long-term debt. For additional information, see Note 11.

FAIR VALUE MEASUREMENTS OF DERIVATIVES

ASC 820, "Fair Value Measurements and Disclosures" (ASC 820), defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). However, as permitted under ASC 820, the Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of its assets and liabilities measured and reported at fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements as it believes that the approach is used by market participants for these types of assets and liabilities. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The Company values derivative instruments based on daily quoted prices from an independent external pricing service. When external quoted market prices are not available for derivative contracts, the Company uses a valuation model that uses volatility assumptions relating to future energy prices based on specific energy markets and utilizes externally available forward market price curves. All derivative instruments are sensitive to market price fluctuations that can occur on a daily basis. For additional information, see Note 12.

STOCK-BASED COMPENSATION

The Company applies the fair value approach to stock compensation and estimates fair value in accordance with provisions of ASC 718, "Compensation – Stock Compensation." Effective February 6, 2009, as a result of the merger, all outstanding shares of the Company were accelerated and vested, the stock compensation plan was terminated and there was no stock-based compensation. The Company recognized $14.5 million of stock compensation expense which was recorded in merger and related costs.

DEBT RELATED COSTS

Debt premiums, discounts, expenses and amounts received or incurred to settle hedges are amortized over the life of the related debt for the Company. The premiums and costs associated with reacquired debt are deferred and amortized over the life of the related new issuance, in accordance with ratemaking treatment for PSE.

STATEMENTS OF CASH FLOWS

PSE funds cash dividends to pay the shareholder of Puget Energy.

The following non-cash investing and financing activities have occurred at the Company:

- PSE incurred capital lease obligations of $37.9 million for automatic meter reading modules and network for the year ended December 31, 2011. PSE did not incur any capital lease obligations for the year ended December 31, 2010. PSE incurred capital lease obligations of $15.9 million for vehicles for the year ended December 31, 2009.
- In connection with the February 6, 2009 merger, Puget Energy assumed $779.3 million of long-term debt in order to pay down PSE short-term debt and assumed $587.8 million of long-term debt to pay off the previous shareholders. This amount was included as part of the purchase price consideration.

ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following tables set forth the components of the Company's accumulated other comprehensive income (loss) at December 31:

PUGET ENERGY	DECEMBER 31,	
(DOLLARS IN THOUSANDS)	2011	2010
Net unrealized loss on energy derivatives	$ (1,113)	$ (2,658)
Net unrealized loss on interest rate swaps	(14,599)	(40,041)
Net unrealized gain and prior service cost on pension plans	(15,195)	39,630
Total Puget Energy, net of tax	$ (30,907)	$ (3,069)

PUGET SOUND ENERGY	DECEMBER 31,	
(DOLLARS IN THOUSANDS)	2011	2010
Net unrealized loss on energy derivatives	$ (12,934)	$ (34,612)
Net unrealized loss on treasury interest rate swaps	(6,941)	(7,257)
Net unrealized loss and prior service cost on pension plans	(168,704)	(115,778)
Total PSE, net of tax	$ (188,579)	$ (157,647)

(2) New Accounting Pronouncements

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Intangibles - Goodwill and Other. In September 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-08, "Intangibles - Goodwill and Other (Topic 350): Testing Goodwill for Impairment". ASU 2011-08 allows an entity the option to qualitatively assess whether it must perform the two-step goodwill impairment test in FASB ASC 350-20, Intangibles - Goodwill and Other. An entity has the option to qualitatively assess whether it is more likely than not (more than 50% likelihood) that the fair value of the reporting unit is less than its carrying amount. If an entity elects to perform the qualitative assessment and determines that it is more likely than not that the reporting unit's fair value is in excess of its carrying amount, no further evaluation is necessary. Otherwise, an entity would perform Step 1 of the goodwill impairment test in ASC 350-20.

ASU 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011, and therefore will become effective for the Company on January 1, 2012 for the quarter ending March 31, 2012. Puget Energy is currently assessing the effects to its impairment testing process, although ASU 2011-08 is not expected to have a significant impact on Puget Energy's consolidated financial statements.

Comprehensive Income. In June 2011, the FASB issued ASU 2011-05, "Comprehensive Income (Topic 220): Presentation of Comprehensive Income." ASU 2011-05 allows an entity the option to present the total of comprehensive income, the components of net income, and the components of OCI either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of OCI along with a total for OCI, and a total amount for comprehensive income. ASU 2011-05 eliminates the option to present the components of OCI as part of the statement of changes in stockholders' equity. The amendments to the ASC in the ASU do not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income.

On December 23, 2011, the FASB issued ASU 2011-12, "Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05." This ASU defers the implementation of only those provisions in ASU 2011-05 that relate to the presentation of reclassification adjustments. The amendments are intended to allow the FASB time to redeliberate whether it is necessary to require entities to present reclassification adjustments from accumulated other comprehensive income in both the statement where net income is presented and the statement where other comprehensive income is presented. ASU 2011-12 affects none of the other requirements in ASU 2011-05, including the requirement to report comprehensive income either in a single continuous statement or in two separate but consecutive statements.

The amendments in ASU 2011-12 and ASU 2011-05 are effective at the same time and should be applied retrospectively. The guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, and therefore will become effective for the Company on January 1, 2012 for the quarter ending March 31, 2012. The Company already complies with the presentation requirement, as the Company presents the total of comprehensive income, the components of net income, and the components of OCI in two separate but consecutive statements. Therefore neither ASU 2011-12 nor ASU 2011-05 will have an impact on the Company's consolidated financial statements.

Fair Value Measurement. In May 2011, the FASB issued ASU 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs." This ASU represents the converged guidance of the FASB and the International Accounting Standards Board on fair value measurement. Many of the amendments to ASC 820, eliminate unnecessary wording differences between International Financial Reporting Standards (IFRS) and GAAP. The ASU expands ASC 820's existing disclosure requirements for fair value measurements categorized in Level 3 by requiring (1) a quantitative disclosure of the unobservable inputs and assumptions used in the measurement, (2) a description of the valuation processes in place, and (3) a narrative description of the sensitivity of the fair value to changes in unobservable inputs and the interrelationships between those inputs. In addition, the level in the fair value hierarchy of items that are not measured at fair value in the statement of financial position whose fair value must be disclosed.

Other amendments to ASC 820 include clarifying the highest and best use and valuation premise for nonfinancial assets, net risk position fair value measurement option for financial assets and liabilities with offsetting positions in market risks or counterparty credit risk, premiums and discounts in fair value measurement, and fair value of an instrument classified in a reporting entity's shareholders' equity.

ASU 2011-04 is effective during interim and annual periods beginning after December 15, 2011, and therefore will become effective for the Company on January 1, 2012 for the quarter ending March 31, 2012. Other than the disclosure requirements, ASU 2011-04 is not expected to have a significant impact on the Company's consolidated financial statements.

Balance Sheet. On December 16, 2011, the FASB issued ASU 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities." The ASU is the result of a joint project with the IASB designed to enhance and provide converged disclosures about financial and derivative instruments that are either offset on the balance sheet, or are subject to an enforceable master netting arrangement (or other similar arrangement). The ASU does not change the conditions for when offsetting is appropriate in US GAAP.

In general, an entity should disclose the effect or potential effect of any rights of setoff associated with recognized assets and liabilities within the scope of the ASU. This information should enable financial statement users to evaluate the impact or potential impact of netting arrangements on its balance sheet.

The ASU is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. Retrospective application of the disclosures is required for all periods presented within the financial statements. Other than the disclosure requirements, ASU 2011-11 is not expected to have an impact on the Company's consolidated financial statements.

(3) Business Combinations (Puget Energy Only)

On February 6, 2009, Puget Holdings completed its merger with Puget Energy. As a result of the merger, Puget Energy is the direct wholly-owned subsidiary of Puget Equico, which is an indirect wholly-owned subsidiary of Puget Holdings. After the merger, Puget Energy has 1,000 shares authorized, of which 200 shares have been issued at a par value of $0.01 per share.

At the time of the merger, each issued and outstanding share of common stock of Puget Energy was cancelled and converted automatically into the right to receive $30.00 in cash, without interest. The fair value of consideration transferred was $3.9 billion, including funding by Puget Holdings of $3.0 billion, debt of $0.6 billion issued by Puget Energy and $0.3 billion that was the result of the stepped-up basis of the investors' previously owned shares.

The table below is the statement of fair value of assets acquired and accrued liabilities assumed as of February 6, 2009 measured in accordance with ASC 805. There were no adjustments subsequent to the merger transaction date.

(Dollars in Thousands)	Amount
Net utility plant	$ 6,346,032
Other property and investments	151,913
Goodwill	1,656,513
Current assets	1,259,505
Long-term and regulatory assets	2,497,355
Long-term debt	2,490,544
Current liabilities	2,173,079
Long-term liabilities	3,358,000

The following tables present the fair value adjustments to Puget Energy's balance sheet and recognition of goodwill in accordance with ASC 805:

ASSETS

(DOLLARS IN THOUSANDS)	FEBRUARY 6, 2009 INCREASE (DECREASE)
Utility plant:	
Electric plant	$ (2,367,756)
Gas plant	(666,278)
Common plant	(302,015)
Less: Accumulated depreciation and amortization	3,381,095
Net utility plant	45,046
Other property and investments:	
Goodwill	1,656,513
Non-utility property	4,250
Total other property and investments	1,660,763
Current assets:	
Materials and supplies	13,700
Fuel and gas inventory	(27,561)
Unrealized gain on derivative instruments	3,765
Power contract acquisition adjustment gain	123,975
Deferred income taxes	32,772
Total current assets	146,651
Other long-term and regulatory assets:	
Other regulatory assets	145,711
Unrealized gain on derivative instruments	1,359
Regulatory asset related to power contracts	317,800
Power contract acquisition adjustment gain	1,016,225
Other	(17,072)
Total other long-term and regulatory assets	1,464,023
Total assets	$ 3,316,483

CAPITALIZATION AND LIABILITIES

(DOLLARS IN THOUSANDS)	FEBRUARY 6, 2009 INCREASE (DECREASE)
Capitalization:	
Common shareholders' equity	$ 1,660,160
Long-term debt	(280,315)
Total capitalization	1,379,845
Current liabilities:	
Unrealized loss on derivative instruments	84,603
Current portion of deferred income taxes	171
Power contract acquisition adjustment loss	118,167
Other	42,679
Total current liabilities	245,620
Long-term liabilities and regulatory liabilities:	
Deferred income taxes	161,094
Unrealized loss on derivative instruments	50,979
Regulatory liabilities	17,417
Regulatory liabilities related to power contracts	1,140,200
Power contract acquisition adjustment loss	199,633
Other deferred credits	121,695
Total long-term liabilities and regulatory liabilities	1,691,018
Total capitalization and liabilities	$ 3,316,483

The carrying values of net utility plant and the majority of regulatory assets and liabilities were determined to be stated at fair value at the acquisition date based on a conclusion that individual assets are subject to regulation by the Washington Commission and the FERC. As a result, the future cash flows associated with the assets are limited to the carrying value plus a return, and management believes that a market participant would not expect to recover any more or less than the carrying value. Furthermore, management believes that the current rate of return on plant assets is consistent with an amount that market participants would expect. ASC 805 requires that the beginning balance of fixed depreciable assets be shown net, with no accumulated amortization recorded, at the date of acquisition, consistent with fresh start accounting.

Other property and investments includes the carrying value of the investments in PSE subsidiaries and other non-utility assets adjusted to fair value based on a combination of the income approach, the market based approach and the cost approach.

The fair values of materials and supplies, which included emission allowances, RECs and carbon financial instruments, were established using a variety of approaches to estimate the market price. The carrying value of fuel inventory was adjusted to its fair value by applying market cost at the date of acquisition.

Energy derivative contracts were reassessed and revalued at the merger date based on forward market prices and forecasted energy requirements.

The fair value assigned to the power contracts was determined using an income approach comparing the contract rate to the market rate for power over the remaining period of the contracts incorporating nonperformance risk. Management also incorporated certain assumptions related to quantities and market presentation that it believes market participants would make in the valuation. The fair value of the power contracts will be amortized as the contracts settle.

Other regulatory assets include service contracts which were valued using the income approach comparing the contract rate to the market rate over the remaining period of the contract.

The fair value of leases was determined using the income approach which calculated the favorable/unfavorable leasehold interests as the net present value of the difference between the contract lease rent and market lease rent over the remaining terms of the contracted lease obligation.

The fair value assigned to long-term debt was determined using two different methodologies. For those securities which were quoted by a third party pricing service based on observable market data, the best indication of fair value was assumed to be the third party's quoted price. For those securities for which the third party did not provide regular pricing, the fair value of the debt was estimated by forecasting out all coupon and principal payments and discounting them to the present value at an approximated discount rate based on PSE's risk of nonperformance as of the merger date.

The merger also triggered a new basis of accounting for Puget Energy's postretirement benefit plans sponsored by PSE under ASC 805 which required remeasuring plan liabilities without the five year smoothing of market-related asset gains and losses.

For the year ended December 31, 2009, Puget Energy incurred pre-tax merger expenses of $47.1 million primarily related to legal fees, transaction advisory services, new credit facility fees, change of control provisions and real estate excise tax. Puget Energy's merger costs in 2009 are not indicative for periods following the acquisition.

One day prior to the merger, PSE defeased its preferred stock in the amount of $1.9 million. In conjunction with the merger on February 6, 2009, Puget Energy contributed $805.3 million in capital to PSE, of which $779.3 million was used to pay off short-term debt owed by PSE, including $188.0 million in short-term debt outstanding through the PSE Funding accounts receivable securitization program that was terminated upon closing of the merger. An additional $26.0 million of the capital contribution was used to pay change in control costs associated with the merger.

(4) Regulation and Rates

FERC Transmission Rate Filing

On January 6, 2012, PSE filed an electric transmission rate case with FERC as well as an increase in ancillary service charges. PSE is requesting a rate increase of $3.8 million with an effective date of April 1, 2012. In the filing, PSE requested a formula transmission rate for network and point-to-point transmission service. A formula rate is a fixed methodology for calculating a rate based upon various cost and billing determinant inputs to recover the operating costs of the transmission system. The formula rate is updated annually and posted on PSE's Open Access Same-Time Information System (OASIS) with an informational filing to FERC. This streamlined process allows PSE to recover its costs on a timely basis, provides for a transparent process with transmission customers and seeks to ensure that there is no under or over collection. Formula transmission rates are encouraged and broadly accepted by FERC.

ELECTRIC REGULATION AND RATES

STORM DAMAGE DEFERRAL ACCOUNTING

The Washington Commission issued a general rate case order that defined deferrable catastrophic/extraordinary losses and provided that costs in excess of $8.0 million annually may be deferred for qualifying storm damage costs that meet the modified IEEE outage criteria for system average interruption duration index. PSE's storm accounting allows deferral of certain storm damage costs. In 2011 and 2010, PSE incurred $4.6 million and $23.5 million, respectively, in storm-related electric transmission and distribution system restoration costs, of which $14.0 million was deferred in 2010. There were no costs deferred in 2011. In January 2012, a storm occurred that resulted in PSE incurring storm damage costs of approximately $65.0 million. Of this amount, approximately $55.6 million was deferred as a regulatory asset.

ELECTRIC GENERAL RATE CASE

On June 13, 2011, PSE filed a general rate increase with the Washington Commission which proposed an increase in electric rates of $160.7 million or 8.1%, to be effective May 2012. PSE requested a weighted cost of capital of 8.42%, or 7.29% after-tax, and a capital structure of 48.0% in common equity with a return on equity of 10.8%. The filing also proposes a conservation savings adjustment mechanism related to energy efficiency services for business and residential customers. On September 1, 2011, PSE filed supplemental testimony to adjust the electric rate increase to $152.3 million, a 7.7% increase, due to changes in projected power costs. On January 17, 2012, PSE filed rebuttal testimony which included a reduction to the requested electric rate increase to $126.0 million. The $26.3 million reduction was primarily due to updates to power costs and to a change to the weighted cost of capital to 8.26%, or 7.17% after-tax, which included a change to the return on equity to 10.75%. Hearings related to this matter were held on February 14 through 17, 2012.

On April 2, 2010, the Washington Commission issued its order in PSE's consolidated electric rate case filed in May 2009 which approved a general rate increase for electric customers of 3.7% annually, or $74.1 million, effective April 8, 2010. In its order, the Washington Commission approved a weighted cost of capital of 8.1% and a capital structure that included 46.0% common equity with an after-tax return on equity of 10.1%.

POWER COST ONLY RATE CASE

Power Cost Only Rate Case (PCORC), a limited-scope proceeding, was approved in 2002 by the Washington Commission to periodically reset power cost rates. In addition to providing the opportunity to reset all power costs, the PCORC proceeding also provides for timely review of new resource acquisition costs and inclusion of such costs in rates at the time the new resource goes into service. To achieve this objective, the Washington Commission has used an expedited six-month PCORC decision timeline rather than the statutory 11-month timeline for a general rate case.

ACCOUNTING ORDERS AND PETITIONS

On May 21, 2008, PSE filed an accounting petition for a Washington Commission order that authorizes the deferral of a settlement payment of $10.7 million incurred as a result of the recent settlement of a lawsuit in the state of Montana over alleged damages caused by the operation of the Colstrip Montana coal-fired steam electric generation facility (Colstrip). The payment was expensed pending resolution of the accounting petition. In the April 2, 2010 general rate case order, the Washington Commission allowed recovery of $8.4 million in PSE's operating costs, which represents the amount of the settlement, net of insurance proceeds.

On November 5, 2008, PSE filed an accounting petition for a Washington Commission order authorizing the deferral and recovery of interest due the Internal Revenue Service (IRS) for tax years 2001 to 2006 along with carrying costs incurred in connection with the interest due. In October 2005, the Washington Commission issued an order authorizing the deferral and recovery of costs associated with increased borrowings necessary to remit deferred taxes to the IRS. In the April 2, 2010 general rate case order, the Washington Commission denied recovery of the interest due to the IRS. PSE expensed the interest deferral of $6.9 million in April 2010.

On November 6, 2008, PSE filed an accounting petition for a Washington Commission order authorizing accounting treatment and amortization related to payments received for taking assignment of Westcoast Pipeline Capacity. The accounting petition seeks deferred accounting treatment and amortization of the regulatory liability to power costs beginning in November 2009 and extending over the remaining primary term of the pipeline capacity contract through October 31, 2018. In the April 2, 2010 general rate case order, the Washington Commission approved the deferral of $7.5 million and amortization as proposed.

On April 17, 2009, the Washington Commission issued an order approving and adopting a settlement agreement that authorized PSE to defer certain ownership and operating costs related to its purchase of the Mint Farm Electric Generating Station (Mint Farm) that were incurred prior to PSE recovering such costs in electric customer rates. Under Washington state law, a jurisdictional electric utility may defer the costs associated with purchasing and operating a natural gas plant that complies with the greenhouse gas (GHG) emissions performance standard until the plant is included in rates or for two years from the date of purchase, whichever occurs sooner. In the April 2, 2010 general rate case order, the Washington Commission approved the prudence of the Mint Farm acquisition and recovery of the deferred costs from the plant's in-service date to the date of the order. The deferred costs are to be amortized over 15 years. As of December 31, 2011, the balance of the regulatory asset, net of amortization was $26.3 million.

On March 13, 2009, PSE filed with the Washington Commission an application for authority to sell and transfer certain assets related to the Company's White River Hydroelectric Project (the Project) to the Cascade Water Alliance (CWA). PSE also requested in its application that the Washington Commission waive applicable provisions of the Revised Code of Washington and Washington Administrative Code with regard to certain surplus property related to the Project, which PSE expects to sell in the near future but which is not part of the CWA transaction. On May 14, 2009, the application for authority to transfer certain assets to CWA was approved by the Washington Commission and the application for waiver with regard to the Surplus Property was denied and requires PSE to seek approval prior to the sale of any property.

On September 30, 2009, PSE filed an accounting petition requesting that the Washington Commission authorize PSE to normalize over 10 years a Treasury grant of $28.7 million received under Section 1603 of the American Recovery and Reinvestment Act of 2009 associated with the Wild Horse expansion project. Treasury grants are tax free grants related to certain renewable energy infrastructure that are available in lieu of the PTC allowed under the Internal Revenue Code. The Washington Commission issued an order approving the accounting petition on December 10, 2009.

On October 16, 2009, PSE filed an accounting petition requesting that the Washington Commission authorize the deferral and recovery of incremental costs associated with protecting the Company's infrastructure, facilitating public safety, and preparing PSE's electric and natural gas system in the Green River Valley flood plain in anticipation of release of water from the United States Army Corps of Engineers' (Corps) Howard Hanson Dam (Dam). In the event of actual flooding, PSE also petitioned the Washington Commission to allow the deferral of costs associated with the repair and restoration of any electric and gas system infrastructure affected by a flood.

On January 28, 2010, the Washington Commission approved PSE's request for authorization to defer the costs associated with restoring the Company's infrastructure, facilitating public safety, and repairing the Company's electric and natural gas system in the Green River Valley flood plain in the event evacuation is required or flooding occurs due to operations associated with the Dam. This authorization is conditioned on PSE incurring incremental operation and maintenance costs in excess of $5.0 million per year associated with repair or restoration of the Company's systems around the Green River. The Washington Commission's order will be effective until the date the Corps confirms that the Dam has been permanently repaired and that Corps' operations will return to normal.

The Washington Commission issued an order in 2010 relating to how REC proceeds should be handled for regulatory accounting and ratemaking purposes. The order required REC proceeds to be recorded as regulatory liabilities and that amounts recorded would accrue interest at the Company's approved after-tax rate of return. In its petition, PSE had sought approval for the use of $21.1 million of REC proceeds to be used as an offset against its California wholesale energy sales regulatory asset. In response to the order, PSE adjusted the carrying value of its regulatory asset in the second quarter of 2010 by $17.8 million (from $21.1 million to $3.3 million), with the $3.3 million then offset against the Company's RECs regulatory liability. The Company's California wholesale energy sales regulatory asset represented unpaid bills for power sold into the markets maintained by the California Independent System Operator during the 2000-2001 California Energy Crisis, the claims of which were settled along with all counterclaims against PSE in a settlement agreement approved by the FERC on July 1, 2009.

On May 20, 2010, PSE filed an accounting petition requesting that the Washington Commission approve: (1) the creation of a regulatory asset account for the prepayments made to the Bonneville Power Administration (BPA) associated with network upgrades to the Central Ferry substation related to the Lower Snake River wind project; (2) the monthly accrual of carrying charges on that regulatory asset at PSE's approved net of tax rate of return; and (3) the ability to provide customers the BPA interest received through a reduction to transmission expense. The petition is still pending approval by the Washington Commission.

PRODUCTION TAX CREDIT / RENEWABLE ENERGY CREDIT

PSE has a tariff which passes the benefits of the PTCs to customers. The tariff is not subject to the sharing bands in the PCA. Prior to July 1, 2010, PSE could adjust the PTC tariff annually based on differences between the PTC credits provided to the customers and the PTC credits actually earned, plus estimated PTC credits for the following year, less interest associated with the deferred tax balance for the PTC credits. Since customers received the benefit of the tax credits as they were generated and the Company did not receive a credit from the IRS until the tax credits were utilized, the Company will be reimbursed for its carrying costs. PSE was reimbursed for carrying costs through December 31, 2011 when the credits that were provided and not used were fully received from customers.

Effective July 1, 2010, the Washington Commission approved a change in PSE's PTC tariff as PSE has not been able to utilize PTCs since 2007, due to insufficient taxable income caused primarily by bonus tax depreciation. The Washington Commission approved PSE suspending its PTC tariff, effective July 1, 2010. This resulted in an overall increase in PSE's electric rates of 1.7%; however, this will not result in an increase in earnings as the benefit of PTCs will pass-through to customers. The tariff also addresses additional federal incentives and therefore has been renamed the Federal Incentive Tracker.

On September 22, 2010, a joint proposal and accounting petition was filed with the Washington Commission by PSE, Washington Commission Staff and Industrial Customers of Northwest Utilities which addressed how to recover PTCs provided to customers that have not been utilized and addresses REC proceeds to be returned to customers. On October 26, 2010, the Washington Commission issued an order granting the joint proposal and accounting petition. The order allows the Company to credit customers for REC revenue received and deferred through November 2009. This credit was set to reduce rates by $27.7 million, or 2.9%, over five months beginning November 2010 through March 2011. RECs received after November 2009 will be retained by PSE and will be used to recapture the benefit of PTCs previously provided to customers.

Due to the uncertainty of realizing the benefit of PTCs, the PTCs will pass-through to customers following the year in which they are able to be utilized on PSE's tax return, rather than in the same year in which they are generated by qualifying wind powered facilities.

TREASURY GRANT

Section 1603 of the American Recovery and Reinvestment Tax Act of 2009 (Section 1603) authorizes the United States Department of the Treasury (U.S. Treasury) to make grants to corporations who place specified energy property in service provided certain conditions are met. The Wild Horse expansion facility was placed into service on November 9, 2009. The Wild Horse facility was expanded from 229 megawatts (MW) to 273 MW through the addition of wind turbines. On December 22, 2009, PSE filed an application with the U.S. Treasury to request a grant on the expansion in the amount of $28.7 million. Section 1603 precludes a recipient from claiming PTCs on property for which a grant is claimed. On February 19, 2010, the U.S. Treasury approved the grant and payment was received in February 2010.

On December 30, 2010, the Washington Commission approved revisions to PSE's Federal Incentive Tracker tariff, effective January 1, 2011, which changed the methodology by which federal benefits are passed-through to customers. The rate schedule will pass-through $5.5 million of the $28.7 million Treasury Grant in 2011. The order authorized PSE to pass back one-tenth of the Treasury Grant on an annual basis and includes 23 months of Treasury Grant amortization to customers from February 2010 through December 2011, which represents the month the Treasury Grant funds were received through the end of the period over which the rates will be set. This represents an overall average rate reduction of 0.3%, with no impact to net income.

PCA MECHANISM

In 2002, the Washington Commission approved a PCA mechanism that provides for a rate adjustment process if PSE's costs to provide customers' electricity varies from a baseline power cost rate established in a rate proceeding. On January 10, 2007, the Washington Commission approved the continuation of the PCA mechanism under the same annual graduated scale but without a cap on excess power costs. All significant variable power supply cost variables (hydroelectric and wind generation, market price for purchased power and surplus power, natural gas and coal fuel price, generation unit forced outage risk and transmission cost) are included in the PCA mechanism.

The PCA mechanism apportions increases or decreases in power costs, on a calendar year basis, between PSE and its customers on a graduated scale. For a discussion of the accounting policy and PCA graduated scale, see Note 1.

GAS REGULATION AND RATES

GAS GENERAL RATE CASE

On June 13, 2011, PSE filed a general rate increase with the Washington Commission which proposed an increase in natural gas rates of $31.9 million or 3.0%, to be effective May 2012. PSE requested a weighted cost of capital of 8.42%, or 7.29% after-tax, and a capital structure of 48.0% in common equity with a return on equity of 10.8%. The filing also proposes a conservation savings adjustment mechanism related to energy efficiency services for business and residential customers. On January 17, 2012, PSE filed rebuttal testimony which included a reduction to the requested natural gas rate increase to $28.6 million. The $3.3 million reduction was primarily due to a change to the weighted cost of capital to 8.26%, or 7.17% after-tax, which included a change to the return on equity to 10.75%. Hearings related to this matter were held on February 14 through 17, 2012.

On April 26, 2011, PSE filed a new tariff for a Natural Gas Pipeline Integrity Program. This program is intended to enhance pipeline safety by providing for the timely recovery of the Company's cost to replace certain natural gas system infrastructure that would emphasize system reliability, integrity and safety which would increase natural gas revenue by $1.9 million or 0.2%. The Washington Commission held a hearing for November 17, 2011 and a Commission Order is the next awaited step in the proceeding.

On March 14, 2011, the Washington Commission issued its order authorizing PSE to increase its natural gas general tariff rates by $19.0 million or 1.8% on an annual basis effective April 1, 2011.

On April 2, 2010, the Washington Commission issued its order, effective April 8, 2010, in PSE's natural gas general rate case filed in May 2009, approving a general rate increase of 0.8% annually or $10.1 million. In its order, the Washington Commission approved a weighted cost of capital of 8.1% and a capital structure that included 46.0% common equity with an after-tax return on equity of 10.1%.

PURCHASED GAS ADJUSTMENT

On October 27, 2011, the Washington Commission approved PSE's PGA natural gas tariff filing effective November 1, 2011, to decrease the rates charged to customers under the PGA. The estimated revenue impact of the approved charge is a decrease of $43.5 million, or 4.3% annually. The rate adjustment has no impact on PSE's net income.

PSE has a PGA mechanism in retail natural gas rates to recover variations in natural gas supply and transportation costs. Variations in natural gas rates are passed through to customers; therefore, PSE's net income is not affected by such variations. Changes in the PGA rates affect PSE's revenue, but do not impact net income as the changes to revenue are offset by increased or decreased purchased gas and gas transportation costs.

The following table sets for PGA rate adjustments approved by the Washington Commission and the corresponding impact on PSE's annual revenue based on the effective dates:

EFFECTIVE DATE	PERCENTAGE INCREASE (DECREASE) IN RATES	ANNUAL INCREASE (DECREASE) IN REVENUE (DOLLARS IN MILLIONS)
November 1, 2011	(4.3)%	$ (43.5)
November 1, 2010 – October 31, 2011	1.9	18.3
October 1, 2009 – October 31, 2010	(17.1)	(198.1)
June 1, 2009 – May 31, 2010	(1.8)	(21.2)
October 1, 2008 – September 30, 2009	11.1	108.8

(5) Dividend Payment Restrictions

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE's electric and natural gas mortgage indentures. At December 31, 2011, approximately $448.6 million of unrestricted retained earnings was available for the payment of dividends under the most restrictive mortgage indenture covenant.

Beginning February 6, 2009, pursuant to the terms of the Washington Commission merger order, PSE may not declare or pay dividends if PSE’s common equity ratio, calculated on a regulatory basis, is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. Also, pursuant to the merger order, PSE may not declare or make any distribution unless on the date of distribution PSE’s corporate credit/issuer rating is investment grade, or, if its credit ratings are below investment grade, PSE’s ratio of Earnings Before Interest, Tax, Depreciation and Amortization (EBITDA) to interest expense for the most recently ended four fiscal quarter periods prior to such date is equal to or greater than 3 to one. The common equity ratio, calculated on a regulatory basis, was 48.2% at December 31, 2011 and the EBITDA to interest expense was 4.4 to one for the 12 months ended December 31, 2011.

PSE’s ability to pay dividends is also limited by the terms of its credit facilities pursuant to which, PSE is not permitted to pay dividends during any Event of Default, or if the payment of dividends would result in an Event of Default (as defined in the facilities), such as failure to comply with certain financial covenants.

Puget Energy’s ability to pay dividends is also limited by the merger order issued by the Washington Commission as well as by the terms of its credit facilities. Pursuant to the merger order, Puget Energy may not declare or make a distribution unless on such date Puget Energy’s ratio of consolidated EBITDA to consolidated interest expense for the four most recently ended fiscal quarters prior to such date is equal to or greater than 2 to one. The EBITDA to interest expense was 2.7 to one for the 12 months ended December 21, 2011.

In accordance with terms of the Puget Energy credit facilities, Puget Energy is limited to paying a dividend within an eight-day period that begins seven days following the delivery of quarterly or annual financial statements to the facility agent. Puget Energy is not permitted to pay dividends during any Event of Default, or if the payment of dividends would result in an Event of Default (as defined in the facilities), such as failure to comply with certain financial covenants. In addition, in order to declare or pay unrestricted dividends, Puget Energy’s interest coverage ratio may not be less than 1.5 to one and its cash flow to net debt outstanding ratio may not be less than 8.25% for the 12 months ending each quarter-end. Puget Energy is also subject to other restrictions such as a “lock up” provision that, in certain circumstances, such as failure to meet certain cash flow tests, may further restrict Puget Energy’s ability to pay dividends.

At December 31, 2011, the Company was in compliance with all applicable covenants, including those pertaining to the payment of dividends.

(6) Utility Plant

Utility Plant (Dollars In Thousands)	Estimated Useful Life (Years)	Puget Energy At December 31, 2011	Puget Energy At December 31, 2010	Puget Sound Energy At December 31, 2011	Puget Sound Energy At December 31, 2010
Electric, gas and common utility plant classified by prescribed accounts :					
Distribution plant	10-50	$ 4,552,087	$ 4,313,447	$ 6,279,340	$ 6,054,961
Production plant	25-125	1,618,196	1,575,694	2,616,855	2,585,864
Transmission plant	45-65	391,080	337,163	516,461	463,546
General plant	5-35	442,216	390,732	499,559	449,980
Intangible plant (including capitalized software)	3-50	112,118	97,458	187,948	184,706
Plant acquisition adjustment	7-30	188,628	183,142	228,593	223,108
Underground storage	25-60	27,139	26,869	40,815	40,558
Liquefied natural gas storage	25-45	12,622	12,440	14,492	14,310
Plant held for future use	NA	18,381	53,945	18,534	54,098
Recoverable Cushion Gas	NA	8,514	8,058	8,514	8,057
Plant not classified	NA	38,998	58,822	38,998	58,822
Capital leases, net of accumulated amortization [1]	1-5	32,207	15,444	32,207	--
Less: accumulated provision for depreciation		(674,782)	(429,038)	(3,714,912)	(3,509,277)
Subtotal		$ 6,767,404	$ 6,644,176	$ 6,767,404	$ 6,628,733
Construction work in progress	NA	1,282,463	628,387	1,282,463	628,387
Net utility plant		$ 8,049,867	$ 7,272,563	$ 8,049,867	$ 7,257,120

1 *Accumulated amortization of capital leases at Puget Energy was $5.7 million in 2011 and $29.6 million in 2010. Accumulated amortization of capital leases at PSE was $5.7 million in 2011. PSE did not have any capital leases in 2010.*

Jointly owned generating plant service costs are included in utility plant service cost. The following table indicates the Company's percentage ownership and the extent of the Company's investment in jointly owned generating plants in service at December 31, 2011. These amounts are also included in the Utility Plant table above.

Jointly Owned Generating Plants (Dollars in Thousands)	Energy Source (Fuel)	Company's Ownership Share	Puget Energy's Share: Plant in Service at Cost	Puget Energy's Share: Accumulated Depreciation	Puget Sound Energy's Share: Plant in Service at Cost	Puget Sound Energy's Share: Accumulated Depreciation
Colstrip Units 1 & 2	Coal	50%	$ 135,623	$ (5,153)	$ 279,391	$ (148,922)
Colstrip Units 3 & 4	Coal	25%	217,813	(16,246)	501,837	(300,269)
Colstrip Units 1 – 4 Common Facilities [1]	Coal	various	83	(10)	252	(179)
Frederickson 1	Gas	49.85%	62,146	570	71,095	(8,379)

1 *The Company's ownership is 50% for Colstrip Units 1 & 2 and 25% for Colstrip Units 3 & 4.*

There were no valuation adjustments to asset retirement obligations (ARO) in conjunction with the merger in 2009. The Company recognized a new ARO in 2011 in the amount of $0.4 million. The Company did not recognize any new AROs in 2010.

The following table describes all changes to the Company's ARO liability:

	At December 31,	
(Dollars in Thousands)	2011	2010
Asset retirement obligation at beginning of period	$ 25,416	$ 24,095
New asset retirement obligation recognized in the period	350	--
Liability settled in the period	(1,722)	(2,341)
Revisions in estimated cash flows	1,154	2,413
Accretion expense	1,342	1,249
Asset retirement obligation at end of period	$ 26,540	$ 25,416

The Company has identified the following obligations, as defined by ASC 410, "Asset Retirement and Environmental Obligations," which were not recognized at December 31, 2011 and 2010:

- a legal obligation under Federal Dangerous Waste Regulations to dispose of asbestos-containing material in facilities that are not scheduled for remodeling, demolition or sales. The disposal cost related to these facilities could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated;

- an obligation under Washington state law to decommission the wells at the Jackson Prairie natural gas storage facility upon termination of the project. Since the project is expected to continue as long as the Northwest pipeline continues to operate, the liability cannot be reasonably estimated;

- an obligation to pay its share of decommissioning costs at the end of the functional life of the major transmission lines. The major transmission lines are expected to be used indefinitely; therefore, the liability cannot be reasonably estimated;

- a legal obligation under Washington state environmental laws to remove and properly dispose of certain under and above ground fuel storage tanks. The disposal costs related to under and above ground storage tanks could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated;

- a potential legal obligation may arise upon the expiration of an existing FERC hydropower license if FERC orders the project to be decommissioned, although PSE contends that FERC does not have such authority. Given the value of ongoing generation, flood control and other benefits provided by these projects, PSE believes that the potential for decommissioning is remote and cannot be reasonably estimated;

(7) Long-Term Debt

PUGET SOUND ENERGY
(DOLLARS IN THOUSANDS)
FIRST MORTGAGE BONDS, POLLUTION CONTROL BONDS , SENIOR NOTES AND JUNIOR SUBORDINATED NOTES

		At December 31,				At December 31,	
Series	Due	2011	2010	Series	Due	2011	2010
7.690%	2011	$ --	$ 260,000	5.000%[1]	2031	$ 138,460	$ 138,460
6.830%	2013	3,000	3,000	5.100%[1]	2031	23,400	23,400
6.900%	2013	10,000	10,000	5.483%	2035	250,000	250,000
5.197%	2015	150,000	150,000	6.724%	2036	250,000	250,000
7.350%	2015	10,000	10,000	6.274%	2037	300,000	300,000
7.360%	2015	2,000	2,000	5.757%	2039	350,000	350,000
6.750%	2016	250,000	250,000	5.764%	2040	250,000	250,000
6.740%	2018	200,000	200,000	5.795%	2040	325,000	325,000
9.570%	2020	--	25,000	4.434%	2041	250,000	--
7.150%	2025	15,000	15,000	5.638%	2041	300,000	--
7.200%	2025	2,000	2,000	4.700%	2051	45,000	--
7.020%	2027	300,000	300,000	6.974%[2]	2067	250,000	250,000
7.000%	2029	100,000	100,000				
Total PSE long-term debt						$ 3,773,860	$ 3,463,860
Unamortized discount on senior notes						(15)	--
Net PSE long-term debt						$3,773,845	$3,463,860

1 *Pollution Control Bonds*
2 *Junior Subordinated Notes*

PUGET ENERGY		At December 31,	
(DOLLARS IN THOUSANDS)	DUE	2011	2010
PSE long-term debt	Various	$ 3,773,845	$ 3,463,860
Fair value adjustment of PSE long-term debt [1]		(276,322)	(284,187)
Term-loan	2014	298,000	782,000
Capital expenditures facility	2014	545,000	258,000
6.500% senior secured note	2020	450,000	450,000
6.000% senior secured note	2021	500,000	--
Original discount on Puget Energy term-loan and capital expenditures facility	N/A	(13,144)	(26,947)
Unamortized discount on senior secured note	N/A	(12)	(13)
Total Puget Energy long-term debt		$ 5,277,367	$ 4,642,713

1 *For additional information regarding fair value adjustments, see Note 3*

PUGET SOUND ENERGY LONG-TERM DEBT

PSE has in effect a shelf registration statement under which it may issue, from time to time, senior notes secured by first mortgage bonds. The Company remains subject to the restrictions of PSE's indentures and credit agreements on the amount of first mortgage bonds that PSE may issue.

On November 22, 2011, PSE issued $45.0 million of senior notes secured by first mortgage bonds. The notes have a term of 40 years and an interest rate of 4.700%. Net proceeds from the offering were used to repay a $25.0 million PSE bond maturing in 2020, with an interest rate of 9.570%

On November 16, 2011, PSE issued $250.0 million of senior notes secured by first mortgage bonds. The notes have a term of 30 years and an interest rate of 4.434%. Net proceeds from the offering were used to repay short-term indebtedness under PSE's capital expenditure credit facility.

On March 25, 2011, PSE issued $300.0 million of senior notes secured by first mortgage bonds. The notes have a term of 30-years and an interest rate of 5.638%. Net proceeds from the note offering were used by PSE to repay short-term debt outstanding under its capital expenditures credit facility, which debt was incurred to fund utility capital expenditures and replenish cash used to repay the February 2011 maturity of $260.0 million of medium-term notes with a 7.69% interest rate.

On June 29, 2010, PSE issued $250.0 million of senior notes secured by first mortgage bonds. The notes have a term of 30 years and an interest rate of 5.764%. Net proceeds from the note offering were used to repay $7.0 million of medium-term notes with a 7.12% interest rate that matured on September 13, 2010 and to repay short-term debt outstanding under the $400.0 million capital expenditure credit facility.

On March 8, 2010, PSE issued $325.0 million of senior notes secured by first mortgage bonds. The notes have a term of 30 years and an interest rate of 5.795%. Net proceeds from the offering were used to replenish funds utilized to repay $225.0 million of senior medium-term notes which matured on February 22, 2010 and carried a 7.96% interest rate. Remaining net proceeds were used to pay down debt under PSE's capital expenditure credit facility.

Substantially all utility properties owned by PSE are subject to the lien of the Company's electric and natural gas mortgage indentures. To issue additional first mortgage bonds under these indentures, PSE's earnings available for interest must exceed certain minimums as defined in the indentures. At December 31, 2011, the earnings available for interest exceeded the required amount.

PUGET SOUND ENERGY POLLUTION CONTROL BONDS

PSE has two series of Pollution Control Bonds outstanding. Amounts outstanding were borrowed from the City of Forsyth, Montana who obtained the funds from the sale of Customized Pollution Control Refunding Bonds issued to finance pollution control facilities at Colstrip Units 3 & 4.

Each series of bonds is collateralized by a pledge of PSE's first mortgage bonds, the terms of which match those of the Pollution Control Bonds. No payment is due with respect to the related series of first mortgage bonds so long as payment is made on the Pollution Control Bonds.

PUGET ENERGY LONG-TERM DEBT

On June 3, 2011, Puget Energy issued $500.0 million of senior secured notes. The notes are secured by an interest in substantially all of Puget Energy's assets, which consists mainly of all the issued and outstanding stock of PSE and the stock of Puget Energy held by Puget Equico LLC (Puget Equico). The notes mature on September 1, 2021 and have an interest rate of 6.0%. Net proceeds from the note offering were used by Puget Energy to repay $484.0 million of its five-year term-loans and $9.9 million to unwind three outstanding interest rate swaps.

On December 6, 2010, Puget Energy issued $450.0 million of senior secured notes. The notes have a term of ten years and an interest rate of 6.5%. The notes are secured by an interest in substantially all of Puget Energy's assets, which consists mainly of all the issued and outstanding stock of PSE and the stock of Puget Energy held by Puget Equico. The notes contain a change of control provision pursuant to which holders of the notes may have the right to require Puget Energy to repurchase all or any part of the notes at a purchase price in cash equal to 101.0% of the principal amount of the notes, plus accrued and unpaid interest. Net proceeds from the note offering were used by Puget Energy to repay a portion of Puget Energy's $1.225 billion five-year term loan.

At the time of the merger in February 2009, Puget Energy entered into a $1.225 billion five-year term-loan and a $1.0 billion credit facility for funding capital expenditures. As of December 31, 2011, Puget Energy had fully drawn the five-year term-loan which, after previous repayments, had a remaining outstanding balance of $298.0 million. Also, as of December 31, 2011, Puget Energy had drawn $545.0 million under the $1.0 billion capital expenditure facility. The term-loan and capital expenditure facility mature in February 2014. These credit agreements contain usual and customary affirmative and negative covenants which are similar to PSE's credit facilities. Puget Energy's credit agreements contain financial covenants based on the following three ratios: cash flow interest coverage, cash flow to net debt outstanding and debt service coverage (cash available for debt service to borrower interest), each as specified in the facilities. Puget Energy certifies its compliance with these covenants each quarter. As of December 31, 2011, Puget Energy was in compliance with all applicable covenants.

In May 2010, Puget Energy's credit facilities were amended, in part, to include a provision for the sharing of collateral with future note holders when notes are issued to repay and reduce the size of the credit facilities.

These facilities contain similar terms and conditions and are syndicated among numerous committed lenders. The agreements provide Puget Energy with the ability to borrow at different interest rate options and include variable fee levels. Borrowings may be at the bank's prime rate or at floating rates based on London Interbank Offered Rate (LIBOR) plus a spread based upon Puget Energy's credit rating. Puget Energy must pay a commitment fee on the unused portion of the $1.0 billion facility. The spreads and the commitment fee depend on Puget Energy's credit ratings. As of the date of this report, the spread over prime rate is 1.0%, the spread to the LIBOR is 2.0% and the commitment fee is 0.75%.

LONG-TERM DEBT MATURITIES

The principal amounts of long-term debt maturities for the next five years and thereafter are as follows:

(DOLLARS IN THOUSANDS)	2012	2013	2014	2015	2016	THEREAFTER	TOTAL
Maturities of:							
PSE long-term debt	$ --	$ 13,000	$ --	$ 162,000	$ 250,000	$ 3,348,860	$ 3,773,860
Puget Energy long-term debt	--	--	843,000	--	--	950,000	1,793,000
Puget Energy long-term debt	$ --	$ 13,000	$ 843,000	$ 162,000	$ 250,000	$ 4,298,860	$ 5,566,860

FINANCIAL COVENANTS

The Company's credit facilities contain financial covenants related to cash flow interest coverage, cash flow to net debt outstanding and debt service coverage, each as specified in the facilities. As of December 31, 2011, the Company is in compliance with its long-term debt financial covenants.

(8) Estimated Fair Value of Financial Instruments

PUGET ENERGY

The following table presents the carrying amounts and estimated fair value of Puget Energy's financial instruments at December 31, 2011 and 2010:

	DECEMBER 31, 2011		DECEMBER 31, 2010	
(DOLLARS IN THOUSANDS)	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
Financial assets:				
Cash and cash equivalents	$ 37,235	$ 37,235	$ 36,557	$ 36,557
Restricted cash	4,183	4,183	5,470	5,470
Notes receivable and other	73,031	73,031	72,419	72,419
Electric derivatives	10,720	10,720	9,762	9,762
Gas derivatives	6,011	6,011	5,971	5,971
Financial liabilities:				
Short-term debt	$ 25,000	$ 25,000	$ 247,000	$ 247,000
Junior subordinated notes	250,000	248,583	250,000	246,864
Current maturities of long-term debt (fixed-rate)	--	--	260,000	261,472
Long-term debt (fixed-rate), net of discount	4,197,511	5,503,571	3,119,660	3,718,303
Long-term debt (variable-rate), net of discount	829,856	856,978	1,013,053	1,083,117
Electric derivatives	264,334	264,334	242,581	242,581
Gas derivatives	206,904	206,904	155,651	155,651
Interest rate derivatives	52,409	52,409	58,003	58,003

PUGET SOUND ENERGY

The following table presents the carrying amounts and estimated fair value of PSE's financial instruments at December 31, 2011 and 2010:

(DOLLARS IN THOUSANDS)	DECEMBER 31, 2011 CARRYING AMOUNT	DECEMBER 31, 2011 FAIR VALUE	DECEMBER 31, 2010 CARRYING AMOUNT	DECEMBER 31, 2010 FAIR VALUE
Financial assets:				
Cash and cash equivalents	$ 31,010	$ 31,010	$ 36,320	$ 36,320
Restricted cash	4,183	4,183	5,470	5,470
Notes receivable and other	73,031	73,031	72,419	72,419
Electric derivatives	10,720	10,720	9,762	9,762
Gas derivatives	6,011	6,011	5,971	5,971
Financial liabilities:				
Short-term debt	$ 25,000	$ 25,000	$ 247,000	$ 247,000
Short-term debt owed by PSE to Puget Energy [1]	29,998	29,998	22,598	22,598
Junior subordinated notes	250,000	248,583	250,000	246,864
Current maturities of long-term debt (fixed-rate)	--	--	260,000	261,472
Non-current maturities of long-term debt (fixed-rate)	3,523,845	4,499,295	2,953,860	3,267,994
Electric derivatives	264,334	264,334	242,581	242,581
Gas derivatives	206,904	206,904	155,651	155,651

1 *Short-term debt owed by PSE to Puget Energy is eliminated upon consolidation of Puget Energy.*

The fair value of long-term notes and variable rate notes were estimated using U.S. Treasury yields and related current market credit spreads, interpolating to the maturity date of each issue.

The carrying values of short-term debt and notes receivable are considered to be a reasonable estimate of fair value. The carrying amount of cash, which includes temporary investments with original maturities of three months or less, is also considered to be a reasonable estimate of fair value.

(9) Liquidity Facilities and Other Financing Arrangements

As of December 31, 2011 and 2010, PSE had $25.0 million and $247.0 million in short-term debt outstanding, respectively, exclusive of the demand promissory note with Puget Energy. Outside of the consolidation of PSE's short-term debt, Puget Energy had no short-term debt outstanding in either year as borrowings under its credit facilities are classified as long-term. PSE's weighted-average interest rate on short-term debt, including borrowing rate, commitment fees and the amortization of debt issuance costs, during 2011 and 2010 was 4.39% and 5.11%, respectively. As of December 31, 2011, PSE and Puget Energy had several committed credit facilities that are described below.

Puget Sound Energy Credit Facilities

PSE maintains three committed unsecured revolving credit facilities that provide, in the aggregate, $1.15 billion in short-term borrowing capability and which mature concurrently in February 2014. These facilities include a $400.0 million credit agreement for working capital needs, a $400.0 million credit facility for funding capital expenditures and a $350.0 million facility to support energy hedging activities.

PSE's credit agreements contain usual and customary affirmative and negative covenants that, among other things, place limitations on PSE's ability to incur additional indebtedness and liens, issue equity, pay dividends, transact with affiliates and make asset dispositions and investments. The credit agreements also contain financial covenants which include a cash flow interest coverage ratio and, in addition, if PSE has a below investment grade credit rating, a cash flow to net debt outstanding ratio (each as specified in the facilities). PSE certifies its compliance with such covenants to participating banks each quarter. As of December 31, 2011, PSE was in compliance with all applicable covenants.

These credit facilities contain similar terms and conditions and are syndicated among numerous committed lenders. The agreements provide PSE with the ability to borrow at different interest rate options and include variable fee levels. The credit agreements allow PSE to borrow at the bank's prime rate or to make floating rate advances at the LIBOR plus a spread that is based upon PSE's credit rating. The working capital facility, as amended, includes a swing line feature allowing same day availability on borrowings up to $50.0 million. The $400.0 million working capital facility and $350.0 million credit agreement to support energy hedging allow for issuing standby letters of credit. PSE must also pay a commitment fee on the unused portion of the credit facilities. The spreads and the commitment fee depend on PSE's credit ratings. As of the date of this report, the spread to the LIBOR is 0.85% and the commitment fee is 0.26%. The $400.0 million working capital facility also serves as a backstop for PSE's commercial paper program.

As of December 31, 2011, $25.0 million was drawn and outstanding under PSE's $400.0 million working capital facility. A $12.5 million letter of credit supporting contracts was outstanding under the facility and there were no amounts outstanding under the commercial paper program. The $400.0 million capital expenditure facility had no amounts drawn and outstanding. No amounts were drawn or outstanding (including letters of credit) under PSE's $350.0 million facility supporting energy hedging. Outside of the credit agreements, PSE had a $5.3 million letter of credit in support of a long-term transmission contract.

Demand Promissory Note. On June 1, 2006, PSE entered into a revolving credit facility with Puget Energy, in the form of a credit agreement and a Demand Promissory Note (Note) pursuant to which PSE may borrow up to $30.0 million from Puget Energy subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lower of the weighted-average interest rates of PSE's outstanding commercial paper interest rate or PSE's senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. At December 31, 2011, the outstanding balance of the Note was $30.0 million. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements.

Puget Energy Credit Facilities

At the time of the merger in February 2009, Puget Energy entered into a $1.225 billion five-year term-loan and a $1.0 billion credit facility for funding capital expenditures. As of December 31, 2011, Puget Energy had fully drawn the five-year term-loan which, after previous repayments, had a remaining outstanding balance of $298.0 million. Also, as of December 31, 2011, Puget Energy had drawn $545.0 million under the $1.0 billion capital expenditure facility. The term-loan and capital expenditure facility mature in February 2014. These credit agreements, which in May 2010 were amended to include a provision for the sharing of collateral with note holders, contained usual and customary affirmative and negative covenants similar to those in PSE's credit facilities.

On February 10, 2012, Puget Energy entered into a $1.0 billion five-year revolving credit facility. Initial borrowings under this facility were used to repay debt outstanding under Puget Energy's term loan and capital expenditure facilities and those agreements were terminated. As a revolving facility, amounts borrowed may be repaid without a reduction in the size of the facility. The revolving credit facility provides Puget Energy the ability to borrow at different interest rate options and includes variable fee levels. Interest rates may be based on the prime rate or LIBOR, plus a spread based on Puget Energy's credit ratings. Puget Energy must pay a commitment fee on the unused portion of the facility. At the inception of this facility, $864.0 million was outstanding, the spread over LIBOR was 2.0% and the commitment fee was 0.375%.

(10) Leases

PSE leases buildings and assets under operating leases. Certain leases contain purchase options, renewal options and escalation provisions. Operating lease expense net of sublease receipts were:

(DOLLARS IN THOUSANDS) AT DECEMBER 31,	
2011	$ 24,789
2010	22,493
2009	31,747

Payments received for the subleases of properties was approximately $0.1 million for each of the years ended 2011, 2010 and 2009.

Future minimum lease payments for non-cancelable leases net of sublease receipts are:

(DOLLARS IN THOUSANDS) AT DECEMBER 31,	OPERATING	CAPITAL
2012	$ 13,873	$ 8,160
2013	14,131	8,160
2014	12,964	8,160
2015	13,008	8,160
2016	14,881	2,718
Thereafter	59,238	--
Total minimum lease payments	$ 128,095	$ 35,358

PSE leased a portion of its owned natural gas transmission pipeline infrastructure under a non-cancelable operating lease to a third party which expired in 2009.

(11) Accounting for Derivative Instruments and Hedging Activities

PSE employs various portfolio optimization strategies, but is not in the business of assuming risk for the purpose of realizing speculative trading revenue. The nature of serving regulated electric customers with its portfolio of owned and contracted electric generation resources exposes PSE and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. Therefore, wholesale market transactions are focused on balancing PSE's energy portfolio, reducing costs and risks where feasible and reducing volatility in costs and margins in the portfolio. PSE's energy risk portfolio management function monitors and manages these risks using analytical models and tools. In order to manage risks effectively, PSE enters into physical and financial transactions which are appropriate for the service territory of PSE and are relevant to its regulated electric and natural gas portfolios.

On the date of the merger, Puget Energy de-designated its derivative contracts that were designated on PSE's books as NPNS or cash flow hedges and recorded such contracts at fair value as either assets or liabilities. Certain contracts meeting the criteria defined in ASC 815 were subsequently re-designated as NPNS or cash flow hedges.

On July 1, 2009, Puget Energy and PSE elected to de-designate all energy related derivative contracts previously recorded as cash flow hedges for the purpose of simplifying its financial reporting. The contracts that were de-designated related to electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and for contracts initiated after such date, all mark-to-market adjustments are recognized through earnings. The amount previously recorded in accumulated OCI is transferred to earnings in the same period or periods during which the hedged transaction affects earnings or sooner if management determines that the forecasted transaction is probable of not occurring. As a result, the Company will continue to experience the earnings impact of these reversals from OCI in future periods. The amount of losses reclassified from OCI to earnings as a result of de-designated cash flow hedges specific to transactions that are probable of not occurring during 2011 for Puget Energy and PSE was $18.4 million and $2.2 million, respectively.

The Company manages its interest rate risk through the issuance of mostly fixed-rate debt of various maturities. The Company utilizes internal cash from operations, commercial paper, and credit facilities to meet short-term funding needs. Short-term obligations are commonly refinanced with fixed-rate bonds or notes when needed and when interest rates are considered favorable. The Company may enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with these debts. As of December 31, 2011, Puget Energy had four interest rate swap contracts outstanding and PSE did not have any outstanding interest rate swap instruments.

In February 2009, Puget Energy entered into the interest rate swap transactions to hedge risk associated with one-month LIBOR floating rate debt. Subsequently, in order to satisfy a commitment the Company made to the Washington Commission and to mitigate refinancing risk, the Company refinanced a portion of the underlying debt hedged by the interest rate swaps during 2010 and again during 2011. As a result of refinancing, the Company de-designated the cash flow hedge accounting relationship between the debt and interest rate swaps in 2010. All fair value gains or losses associated with the interest rate swaps subsequent to the de-designation are recorded in earnings. At December 31, 2011, the outstanding notional balance of the interest rate swaps is $1.28 billion, compared to the variable rate debt balance of only $843 million. Under the existing credit agreements, the Company may retain a portion of those swaps that are in excess of the underlying debt (not economic hedges) until June 2012 at which point the Company may decide to unwind or follow other strategies to mitigate the risk of those un-hedged swaps. During the period in which the Company's interest rate swaps are in excess of the Company's variable rate debt, the Company will be subject to additional interest rate risk. The Company has settled approximately $277 million of the interest rate swaps on February 15, 2012. The transaction did not impact the consolidated statements of income as the fair value losses for those swaps had already been recorded through earnings.

The Company refinanced the remaining $843 million of outstanding variable rate debt on February 10, 2012 in order to further stagger debt maturity dates. Since the refinancing replaced debt with like debt, the original hedged forecast interest payments are still probable of occurring and there is no anticipated reclassification of existing amounts deferred in accumulated OCI to earnings as a result of this transaction. Puget Energy recorded a $21.2 million loss related to the swaps to interest expense during 2011.

The following tables present the fair value and locations of Puget Energy's derivative instruments recorded on the balance sheets at December 31, 2011 and 2010:

DERIVATIVES NOT DESIGNATED AS HEDGING INSTRUMENTS

PUGET ENERGY	DECEMBER 31, 2011		DECEMBER 31, 2010	
(DOLLARS IN THOUSANDS)	ASSETS [1]	LIABILITIES [1]	ASSETS [1]	LIABILITIES [1]
Interest rate swaps:				
Current	$ --	$ 25,210	$ --	$ 30,047
Long-term		27,199	--	27,956
Electric portfolio:				
Current	5,212	173,582	4,716	142,780
Long-term	5,508	90,752	5,046	99,801
Gas portfolio: [2]				
Current	1,435	128,297	2,784	100,273
Long-term	4,576	78,607	3,187	55,378
Total derivatives	$ 16,731	$ 523,647	$ 15,733	$ 456,235

1 *Balance sheet location: Unrealized (gain) loss on derivative instruments.*

2 *Puget Energy had a derivative liability and an offsetting regulatory asset of $200.9 million at December 31, 2011 and $149.7 million at December 31, 2010 related to financial contracts used to economically hedge the cost of physical gas purchased to serve natural gas customers. All fair value adjustments on derivatives relating to the natural gas business have been reclassified to a deferred account in accordance with ASC 980 due to the PGA mechanism. All increases and decreases in the cost of natural gas supply are passed on to customers with the PGA mechanism and the gains and losses on the hedges in future periods will be recorded as gas costs.*

The following table presents the fair value and locations of PSE's derivative instruments recorded on the balance sheet at December 31, 2011 and 2010:

DERIVATIVES NOT DESIGNATED AS HEDGING INSTRUMENTS

PUGET SOUND ENERGY	DECEMBER 31, 2011		DECEMBER 31, 2010	
(DOLLARS IN THOUSANDS)	ASSETS [1]	LIABILITIES [1]	ASSETS [1]	LIABILITIES [1]
Electric portfolio:				
Current	$ 5,212	$ 173,582	$ 4,716	$ 142,780
Long-term	5,508	90,752	5,046	99,801
Gas portfolio: [2]				
Current	1,435	128,297	2,784	100,273
Long-term	4,576	78,607	3,187	55,378
Total derivatives	$ 16,731	$ 471,238	$ 15,733	$ 398,232

1 *Balance sheet location: Unrealized (gain) loss on derivative instruments.*

2 *PSE had a derivative liability and an offsetting regulatory asset of $200.9 million at December 31, 2011 and $149.7 million at December 31, 2010 related to financial contracts used to economically hedge the cost of physical gas purchased to serve natural gas customers. All fair value adjustments on derivatives relating to the natural gas business have been reclassified to a deferred account in accordance with ASC 980 due to the PGA mechanism. All increases and decreases in the cost of natural gas supply are passed on to customers with the PGA mechanism and the gains and losses on the hedges in future periods will be recorded as gas costs.*

For further details regarding the fair value of derivative instruments and their Level categorization, see Note 12.

The following table presents the net unrealized (gain) loss of Puget Energy's derivative instruments recorded on the statements of income for the years ended December 31, 2011, 2010 and 2009:

PUGET ENERGY (DOLLARS IN THOUSANDS)	SUCCESSOR: YEAR ENDED DECEMBER 31, 2011	SUCCESSOR: YEAR ENDED DECEMBER 31, 2010	SUCCESSOR: FEBRUARY 6, 2009 – DECEMBER 31, 2009	PREDECESSOR: JANUARY 1, 2009 – FEBRUARY 5, 2009
Gas / Power NPNS [1]	$ (11,677)	$ (40,564)	$ (42,328)	$ --
Gas for power generation	(23,993)	37,535	(71,921)	3,696
Power exchange	--	(2,619)	(2,247)	(588)
Power	47,164	59,743	(51,698)	759
Credit reserve [2]	--	--	11,593	--
Total net unrealized (gain) loss on derivative instruments	$ 11,494	$ 54,095	$ (156,601)	$ 3,867
Interest expense – interest rate swaps	$ 21,159	$ (10,918)	$ --	$ --
Other deductions – interest rate swaps	$ 12,388	$ 7,319	$ --	$ --

1 *Amount represents amortization expense related to contracts that were recorded at fair value at the time of the merger order.*

2 *Beginning in the second quarter 2009, the credit reserve was incorporated as a component of the individual derivative value and not recorded separately.*

The following table presents the net unrealized (gain) loss of PSE's derivative instruments recorded on the statements of income for the years ended December 31, 2011, 2010 and 2009:

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2011	2010	2009
Gas for power generation	$ (4,043)	$ 91,666	$ (2,835)
Power exchange	--	(2,620)	(2,822)
Power	58,189	77,907	4,321
Credit reserve [1]		--	82
Total net unrealized (gain) loss on derivative instruments	$ 54,146	$ 166,953	$ (1,254)

1 *Beginning in the second quarter 2009, the credit reserve was incorporated as a component of the individual derivative value and not recorded separately.*

The following tables present the effect of hedging instruments on Puget Energy's OCI and statements of income for the years ended December 31, 2011, 2010 and 2009:

PUGET ENERGY (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2011				
DERIVATIVES IN CASH FLOW HEDGING RELATIONSHIPS	GAIN (LOSS) RECOGNIZED IN OCI ON DERIVATIVES [1] (EFFECTIVE PORTION [2])	GAIN (LOSS) RECLASSIFIED FROM ACCUMULATED OCI INTO INCOME (EFFECTIVE PORTION [3]) LOCATION		GAIN (LOSS) RECOGNIZED IN INCOME ON DERIVATIVES (INEFFECTIVE PORTION AND AMOUNT EXCLUDED FROM EFFECTIVENESS TESTING [3]) LOCATION	
Interest rate contracts:	$ --	Interest expense	$ (39,143)		$ --
Commodity contracts:					
Electric derivatives	--	Electric generation fuel	(679)	Net unrealized gain on derivative instruments	--
Electric derivatives	--	Purchased electricity	(1,699)	Net unrealized loss on derivative instruments	--
Total	$ --		$ (41,521)		$ --

Puget Energy (Dollars in Thousands)	Year Ended December 31, 2010				
Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives [1] (Effective Portion [2])	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion [3])		Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion and Amount Excluded from Effectiveness Testing [3])	
		Location		Location	
Interest rate contracts:	$ (58,175)	Interest expense	$ (33,887)		$ --
Commodity contracts: Electric derivatives	--	Electric generation fuel	(3,347)	Net unrealized gain on derivative instruments	--
Electric derivatives	--	Purchased electricity	(3,453)	Net unrealized loss on derivative instruments	--
Total	$ (58,175)		$ (40,687)		$ --

Puget Energy (Dollars in Thousands)	Successor February 6, 2009 – December 31, 2009				
Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives [1] (Effective Portion [2])	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion [3])		Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion and Amount Excluded from Effectiveness Testing [3])	
		Location		Location	
Interest rate contracts:	$ (22,777)	Interest expense	$ (29,052)		$ --
Commodity contracts: Electric derivatives	(19,933)	Electric generation fuel	(25,296)	Net unrealized gain on derivative instruments	325
Electric derivatives	(6,289)	Purchased electricity	(4,157)	Net unrealized loss on derivative instruments	(2,897)
Total	$ (48,999)		$ (58,505)		$ (2,572)

1 *On July 1, 2009 all electric and gas related cash flow hedge relationships were de-designated. Subsequent measurements of fair value are recorded through earnings, not OCI.*

2 *Changes in OCI are reported in after-tax dollars.*

3 *A reclassification of a loss in OCI increases accumulated OCI and decreases earnings. Amounts reported are in pre-tax dollars.*

PUGET ENERGY (DOLLARS IN THOUSANDS)	PREDECESSOR JANUARY 1, 2009 - FEBRUARY 5, 2009				
DERIVATIVES IN CASH FLOW HEDGING RELATIONSHIPS	GAIN (LOSS) RECOGNIZED IN OCI ON DERIVATIVES (EFFECTIVE PORTION [1,2])	GAIN (LOSS) RECLASSIFIED FROM ACCUMULATED OCI INTO INCOME (EFFECTIVE PORTION [3])		GAIN (LOSS) RECOGNIZED IN INCOME ON DERIVATIVES (INEFFECTIVE PORTION AND AMOUNT EXCLUDED FROM EFFECTIVENESS TESTING [3])	
		LOCATION		LOCATION	
Interest rate contracts:	$ --	Interest expense	$ (41)		$ --
Commodity contracts:					
Electric derivatives	(20,791)	Electric generation fuel	(5,003)	Net unrealized loss on derivative instruments	--
Electric derivatives	(3,371)	Purchased electricity	(1,934)	Net unrealized loss on derivative instruments	(986)
Total	$(24,162)		$ (6,978)		$ (986)

1 *Changes in OCI are reported in after-tax dollars.*

2 *The balances associated with the components of accumulated other comprehensive income (loss) on the Predecessor basis were eliminated as a result of push-down accounting effective February 6, 2009, when the Successor period began.*

3 *A reclassification of a loss in OCI increases accumulated OCI and decreases earnings. Amounts reported are in pre-tax dollars.*

The following table presents the effect of hedging instruments on PSE's OCI and statements of income for the years ended December 31, 2011, 2010 and 2009:

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31,										
DERIVATIVES IN CASH FLOW HEDGING RELATIONSHIPS	GAIN (LOSS) RECOGNIZED IN OCI ON DERIVATIVES [1] (EFFECTIVE PORTION [2])			GAIN (LOSS) RECLASSIFIED FROM ACCUMULATED OCI INTO INCOME (EFFECTIVE PORTION [3])				GAIN (LOSS) RECOGNIZED IN INCOME ON DERIVATIVES (INEFFECTIVE PORTION AND AMOUNT EXCLUDED FROM EFFECTIVENESS TESTING [3])			
	2011	2010	2009	LOCATION	2011	2010	2009	LOCATION	2011	2010	2009
Interest rate contracts:	$ --	$ --	$ --	Interest expense	$ (488)	$ (488)	$ (488)		$ --	$ --	$ --
Commodity contracts: Electric derivatives:	--	--	(49,848)	Electric generation fuel	(20,625)	(57,479)	(117,524)	Net unrealized gain on derivative instruments	--	--	--
Electric derivatives	--	--	(11,429)	Purchased electricity	(12,726)	(17,207)	(20,686)	Net unrealized loss on derivative instruments	--	--	(2,749)
Total	$ --	$ --	$(61,277)		$(33,839)	$(75,174)	$(138,698)		$ --	$ --	$ (2,749)

1 *On July 1, 2009 all electric and gas related cash flow hedge relationships were de-designated. Subsequent measurements of fair value are recorded through earnings, not OCI.*

2 *Changes in OCI are reported in after-tax dollars.*

3 *A reclassification of a loss in OCI increases accumulated OCI and decreases earnings. Amounts reported are in pre-tax dollars.*

For derivative instruments that meet cash flow hedge criteria, the effective portion of the gain or loss on the derivative is reported as a component of OCI and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivatives representing hedge ineffectiveness are recognized in current earnings. Puget Energy expects that $14.0 million of losses in OCI will be reclassified into earnings within the next twelve months. PSE expects that $12.9 million of losses in OCI will be reclassified into earnings within the next twelve months. The maximum length of time over which Puget Energy and PSE are hedging their exposure to the variability in future cash flows extends to February 2015 for purchased electricity contracts and to October 2015 for gas for power generation contracts. For Puget Energy interest rate swaps, the maximum length of forecasted transactions deferred in OCI extends to February 2014.

The following tables present the effect of Puget Energy's derivatives not designated as hedging instruments on income during the years ended December 31, 2011, 2010 and 2009:

PUGET ENERGY (DOLLARS IN THOUSANDS)	LOCATION	YEAR ENDED DECEMBER 31, 2011	YEAR ENDED DECEMBER 31, 2010
Interest rate contracts:			
	Other deductions	$ (28,601)	$ (7,955)
	Interest expense	(46,045)	9,423
Commodity contracts:			
Electric derivatives	Net unrealized gain (loss) on derivative instruments	(23,170) [1]	(94,659) [2]
	Electric generation fuel	(98,208)	(100,514)
	Purchased electricity	(66,845)	(36,886)
Total gain (loss) recognized in income on derivatives		$ (262,869)	$ (230,591)

PUGET ENERGY (DOLLARS IN THOUSANDS)	LOCATION	SUCCESSOR FEBRUARY 6, 2009 – DECEMBER 31, 2009	PREDECESSOR JANUARY 1, 2009 – FEBRUARY 5, 2009
Interest rate contracts:			
	Other deductions	$ --	$ --
	Interest income	$ --	$ --
Commodity contracts:			
Electric derivatives	Net unrealized gain (loss) on derivative instruments	117,515 [3]	(2,881) [4]
	Electric generation fuel	(88,185)	(863)
	Purchased electricity	(56,498)	(243)
Total gain (loss) recognized in income on derivatives		$ (27,168)	$ (3,987)

1 *Differs from the amount stated in the statements of income as it does not include $11.7 million of amortization expense related to contracts that were recorded at fair value at the time of the merger and subsequently designated as NPNS.*

2 *Differs from the amount stated in the statements of income as it does not include $40.6 million of amortization expense related to contracts that were recorded at fair value at the time of the merger and subsequently designated as NPNS.*

3 *Differs from the amount stated in the statements of income as it does not include $41.7 million of amortization expense related to contracts that were recorded at fair value at the time of the merger and subsequently designated as NPNS and $(2.6) million related to hedge ineffectiveness.*

4 *Differs from the amount stated in the statements of income as it does not include $(1.0) million related to hedge ineffectiveness.*

The following table presents the effect of PSE's derivatives not designated as hedging instruments on income during the years ended December 31, 2011, 2010 and 2009:

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	LOCATION	YEAR ENDED DECEMBER 31, 2011	2010	2009
Commodity contracts:				
Electric derivatives	Net unrealized gain (loss) on derivative instruments	$ (54,146)	$ (166,953)	$ 4,003 [1]
	Electric generation fuel	(98,208)	(100,514)	(89,255)
	Purchased electricity	(66,845)	(36,886)	(40,770)
Total gain (loss) recognized in income on derivatives		$ (219,199)	$ (304,353)	$ (126,022)

1 *Differs from the amount stated in the statements of income as it does not include $(2.7) million related to hedge ineffectiveness*

The Company had the following outstanding contracts as of December 31, 2011:

PUGET ENERGY AT DECEMBER 31, 2011	NUMBER OF UNITS
Derivatives not designated as hedging instruments:	
Interest rate swaps	$1.277 billion

PUGET ENERGY AND PUGET SOUND ENERGY AT DECEMBER 31, 2011	NUMBER OF UNITS
Derivatives not designated as hedging instruments:	
Gas derivatives [1]	486,950,216 MMBtus
Electric generation fuel	140,557,000 MMBtus
Purchased electricity	12,264,650 MWhs

[1] *Unrealized gains (losses) on gas derivatives are offset by a regulatory asset or liability in accordance with ASC 980 due to the PGA mechanism.*

The Company is exposed to credit risk primarily through buying and selling electricity and natural gas to serve its customers. Credit risk is the potential loss resulting from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for, among other things, counterparty credit analysis, exposure measurement, exposure monitoring, and exposure mitigation.

The Company monitors counterparties that have significant swings in credit default swap rates, have credit rating changes by external rating agencies, have changes in ownership or are experiencing financial problems. Where deemed appropriate, the Company may request collateral or other security from its counterparties to mitigate potential credit default losses. Criteria employed in this decision include, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure.

It is possible that volatility in energy commodity prices could cause the Company to have material credit risk exposure with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. However, as of December 31, 2011, approximately 99.9% of the Company's energy portfolio exposure, excluding NPNS transactions, is with counterparties that are rated at least investment grade by the major rating agencies and 0.1% are either rated below investment grade or not rated by rating agencies. The Company assesses credit risk internally for counterparties that are not rated.

The Company generally enters into the following master agreements: (1) WSPP, Inc. (WSPP) agreements – standardized power sales contract in the electric industry; (2) International Swaps and Derivatives Association (ISDA) agreements – standardized financial gas and electric contracts; and (3) North American Energy Standards Board (NAESB) agreements – standardized physical gas contracts. The Company believes that such agreements reduce credit risk exposure because such agreements provide for the netting and offset of monthly payments and, in the event of counterparty default, termination payments.

The Company computes credit reserves at a master agreement level by counterparty (i.e., WSPP, ISDA, or NAESB). The Company considers external credit ratings and market factors, such as credit default swaps and bond spreads, in determination of reserves. The Company recognizes that external ratings may not always reflect how a market participant perceives a counterparty's risk of default. The Company uses both default factors published by Standard & Poor's and factors derived through analysis of market risk, which reflect the application of an industry standard recovery rate. The Company selects a default factor by counterparty at an aggregate master agreement level based on a weighted average default tenor for that counterparty's deals. The default tenor is used by weighting the fair value and contract tenors for all deals for each counterparty and coming up with an average value. The default factor used is dependent upon whether the counterparty is in a net asset or a net liability position after applying the master agreement levels.

The Company applies the counterparty's default factor to compute credit reserves for counterparties that are in a net asset position. Moreover, the Company applies its own default factor to compute credit reserves for counterparties that are in a net liability position. Credit reserves are booked as contra accounts to unrealized gain (loss) positions. As of December 31, 2011, the Company was in a net liability position with the majority of counterparties, so the default factors of counterparties did not have a significant impact on reserves for the year. The majority of the Company's derivative contracts are with financial institutions and other utilities operating within the Western Electricity Coordinating Council. Despite its net liability position, PSE was not required to post any additional collateral with any of its counterparties. Additionally, PSE did not trigger any collateral requirements with any of its counterparties nor were any of PSE's counterparties required to post additional collateral resulting from credit rating downgrades.

As of December 31, 2011, the Company did not have any outstanding energy supply and interest rate swap contracts with counterparties that contained credit risk related contingent features, which could result in a counterparty requesting immediate payment or demanding immediate and ongoing full overnight collateralization on derivative instruments in a net liability position.

The table below presents the fair value of the overall contractual contingent liability positions for the Company's derivative activity at December 31, 2011:

PUGET ENERGY AND PUGET SOUND ENERGY

CONTINGENT FEATURE (DOLLARS IN THOUSANDS)	FAIR VALUE [1] LIABILITY	POSTED COLLATERAL	CONTINGENT COLLATERAL
Credit rating [2]	$ (52,048)	$ --	$ 52,048
Requested credit for adequate assurance	(95,959)	--	--
Forward value of contract [3]	(16,342)	--	--
Total	$ (164,349)	$ --	$ 52,048

1 *Represents the derivative fair value of contracts with contingent features for counterparties in net derivative liability positions at December 31, 2011. Excludes NPNS, accounts payable and accounts receivable liability.*

2 *Failure by PSE to maintain an investment grade credit rating from each of the major credit rating's agencies provides counterparties a contractual right to demand collateral.*

3 *Collateral requirements may vary, based on changes in forward value of underlying transactions relative to contractually defined collateral thresholds.*

(12) Fair Value Measurements

ASC 820 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy defined by ASC 820 are as follows:

> Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities. Equity securities that are also classified as cash equivalents are considered Level 1 if there are unadjusted quoted prices in active markets for identical assets or liabilities.

> Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and options.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. At each balance sheet date, the Company performs an analysis of all instruments subject to ASC 820 and includes in Level 3 all of those instruments whose fair value is based on significant unobservable inputs.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. If a fair value measurement relies on inputs from different levels of the hierarchy, the entire measurement must be placed based on the lowest level input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. On a daily basis, the Company obtains quoted forward prices for the electric and natural gas market from an independent external pricing service. Those forward price quotes are then used in addition to other various inputs to determine the reported fair value. Some of the inputs include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), assumptions for time value and also the impact of the Company's nonperformance risk on its liabilities.

As of December 31, 2011, the Company considered the markets for its electric and natural gas Level 2 derivative instruments to be actively traded. Management's assessment is based on the trading activity volume in real-time and forward electric and natural gas markets. The Company regularly confirms the validity of pricing service quoted prices (e.g. Level 2 in the fair value hierarchy) used to value commodity contracts to the actual prices of commodity contracts entered into during the most recent quarter.

The following tables set forth, by level within the fair value hierarchy, the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis and the reconciliation of the changes in the fair value of derivatives classified as Level 3 in the fair value hierarchy as of December 31, 2011 and 2010:

PUGET ENERGY	Fair Value Measurement At December 31, 2011				Fair Value Measurement At December 31, 2010			
(Dollars in Thousands)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Cash equivalents	$ 14,809	$ 1,958	$ --	$ 16,767	$ 15,184	$ 5,450	$ --	$ 20,634
Restricted cash	2,043	735	--	2,778	3,246	--	--	3,246
Electric derivative instruments	--	2,340	8,380	10,720	--	1,874	7,888	9,762
Gas derivative instruments	--	--	6,011	6,011	--	1,487	4,484	5,971
Interest rate derivative instruments	--	--	--	--	--	--	--	--
Total assets	$ 16,852	$ 5,033	$ 14,391	$ 36,276	$ 18,430	$ 8,811	$ 12,372	$ 39,613
Liabilities:								
Electric derivative instruments	$ --	$ 165,643	$ 98,691	$ 264,334	$ --	$ 147,257	$ 95,324	$ 242,581
Gas derivative instruments	--	195,852	11,052	206,904	--	147,308	8,343	155,651
Interest rate derivative instruments	--	52,409	--	52,409	--	58,003	--	58,003
Total liabilities	$ --	$ 413,904	$ 109,743	$ 523,647	$ --	$ 352,568	$ 103,667	$ 456,235

Puget Energy Level 3 Roll-Forward Net (Liability) (Dollars in Thousands)	Successor Year Ended December 31, 2011	Successor Year Ended December 31, 2010	Successor February 6, 2009 - December 31, 2009	Predecessor January 1, 2009 - February 5, 2009
Balance at beginning of period	$ (91,295)	$ (100,333)	$ (185,813) [1]	$ (132,256)
Changes during period:				
Realized and unrealized energy derivatives				
- included in earnings	(56,499)	(112,180)	(14,832)	(627)
- included in other comprehensive income	--	--	(17,429)	(14,821)
- included in regulatory assets/liabilities	(250)	(2,665)	(4,345)	(1,410)
Settlements [2]	37,482	29,832	26,374	2,154
Transferred into Level 3	(306)	225	(8,611)	--
Transferred out of Level 3	15,516	93,826	104,323	8,560
Balance at end of period	$ (95,352)	$ (91,295)	$ (100,333)	$ (138,400)

1 *The beginning balance for the Successor period was adjusted to reflect the impact of certain fair value adjustments from the merger transaction.*

2 *There were no purchases or issuances for 2011 or prior years.*

Puget Sound Energy (Dollars in Thousands)	Fair Value measurement At December 31, 2011 Level 1	Level 2	Level 3	Total	Fair Value Measurement At December 31, 2010 Level 1	Level 2	Level 3	Total
Assets:								
Cash equivalents	$ 9,200	$ 1,958	$ --	$ 11,158	$ 15,184	$ 5,450	$ --	$ 20,634
Restricted cash	2,043	735	--	2,778	3,246	--	--	3,246
Electric derivative instruments	--	2,340	8,380	10,720	--	1,874	7,888	9,762
Gas derivative instruments	--	--	6,011	6,011	--	1,487	4,484	5,971
Total assets	$ 11,243	$ 5,033	$ 14,391	$ 30,667	$ 18,430	$ 8,811	$ 12,372	$ 39,613
Liabilities:								
Electric derivative instruments	$ --	$ 165,643	$ 98,691	$ 264,334	$ --	$ 147,257	$ 95,324	$ 242,581
Gas derivative instruments	--	195,852	11,052	206,904	--	147,308	8,343	155,651
Total liabilities	$ --	$ 361,495	$ 109,743	$ 471,238	$ --	$ 294,565	$ 103,667	$ 398,232

Puget Sound Energy Level 3 Roll-Forward Net (Liability) (Dollars in Thousands)	Year Ended December 31, 2011	2010	2009
Balance at beginning of period	$ (91,295)	$ (100,333)	$ (132,256)
Changes during period:			
Realized and unrealized energy derivatives			
- included in earnings	(56,499)	(112,180)	(776)
- included in other comprehensive income	--	--	(38,047)
- included in regulatory assets/liabilities	(250)	(2,665)	(7,824)
Settlements [1]	37,482	29,832	28,779
Transferred into Level 3	(306)	225	(6,778)
Transferred out of Level 3	15,516	93,826	56,569
Balance at end of period	$ (95,352)	$ (91,295)	$ (100,333)

1 *There were no purchases or issuances for 2011 or prior years.*

Realized gains and losses on energy derivatives for Level 3 recurring items are included in energy costs in the Company's consolidated statements of income under purchased electricity, electric generation fuel or purchased natural gas when settled.

Unrealized gains and losses on energy derivatives for Level 3 recurring items are included in the net unrealized (gain) loss on derivative instruments section in the Company's consolidated statements of income.

Certain energy derivative instruments are classified as Level 3 in the fair value hierarchy because Level 3 inputs are significant to their fair value measurement. Energy derivatives transferred out of Level 3 represent existing assets or liabilities that were classified as Level 3 at the start of the reporting period for which the lowest significant input became observable during the current reporting period and were transferred into Level 2. Conversely, energy derivatives transferred into Level 3 from Level 2 represent scenarios in which the lowest significant input became unobservable during the current reporting period. The Company had no transfers between Level 2 and Level 1 during the year ended December 31, 2011, 2010 or 2009.

(13) Employee Investment Plans

The Company has a qualified Employee Investment Plan under which employee salary deferrals and after-tax contributions are used to purchase several different investment fund options. For employees under the Cash Balance formula, PSE will match 100% of an employee retirement plan contribution up to 6% of an employee annual salary and make an additional year-end contribution equal to 1% of base pay. For employees grandfathered under the Final Average Earning formula pension plan, PSE will match 55% of an employee's investment plan contribution up to 6% of an employee annual salary. PSE's contributions to the Employee Investment Plan were \$13.5 million, \$11.8 million and \$11.4 million for the years 2011, 2010 and 2009, respectively. The Employee Investment Plan eligibility requirements are set forth in the plan documents.

(14) Retirement Benefits

PSE has a defined benefit pension plan covering substantially all PSE employees. Pension benefits earned are a function of age, salary and years of service. PSE also maintains a non-qualified Supplemental Executive Retirement Plan (SERP) for its key senior management employees. In addition to providing pension benefits, PSE provides certain health care and life insurance benefits for employees. These benefits are provided principally through an insurance company. The insurance premiums are based on the benefits provided during the year, and are paid primarily by retirees.

The February 6, 2009 merger of Puget Energy with Puget Holdings triggered a new basis of accounting for PSE's retirement benefit plans in the Puget Energy consolidated financial statements. Such purchase accounting adjustments associated with the remeasurement of retirement plans are recorded at Puget Energy.

The following tables summarize Puget Energy's change in benefit obligation, change in plan assets, net periodic benefit cost and other changes in OCI for the years ended December 31, 2011 and 2010:

PUGET ENERGY	QUALIFIED PENSION BENEFITS		SERP PENSION BENEFITS		OTHER BENEFITS	
(DOLLARS IN THOUSANDS)	2011	2010	2011	2010	2011	2010
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 532,615	$ 504,786	$ 44,322	$ 39,152	$ 16,579	$ 15,953
Service cost	15,822	16,089	1,241	1,024	113	106
Interest cost	26,263	27,975	2,192	2,165	807	880
Amendment	--	(21,866)	--	--	--	--
Actuarial loss	18,485	32,163	4,467	3,663	384	867
Benefits paid	(27,188)	(26,532)	(2,687)	(1,682)	(1,855)	(2,030)
Medicare part D subsidy received	--	--	--	--	408	803
Curtailment loss/(gain)	--	--	(1,165)[1]	--	--	--
Benefit obligation at end of period	$ 565,997	$ 532,615	$ 48,370	$ 44,322	$ 16,436	$ 16,579

1 *A curtailment gain was recognized in OCI due to the plan amendment that ceased SERP benefits for non-officers still in the plan as of December 31, 2011.*

PUGET ENERGY	QUALIFIED PENSION BENEFITS		SERP PENSION BENEFITS		OTHER BENEFITS	
(DOLLARS IN THOUSANDS)	2011	2010	2011	2010	2011	2010
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 526,469	$ 485,689	$ --	$ --	$ 8,288	$ 8,790
Actual return on plan assets	(24,495)	55,312	--	--	(170)	1,140
Employer contribution	5,000	12,000	2,687	1,682	943	388
Benefits paid	(27,188)	(26,532)	(2,687)	(1,682)	(1,855)	(2,030)
Fair value of plan assets at end of period	$ 479,786	$ 526,469	$ --	$ --	$ 7,206	$ 8,288
Funded status at end of period	$ (86,211)	$ (6,146)	$ (48,370)	$ (44,322)	$ (9,230)	$ (8,291)

PUGET ENERGY	QUALIFIED PENSION BENEFITS		SERP PENSION BENEFITS		OTHER BENEFITS	
(DOLLARS IN THOUSANDS)	2011	2010	2011	2010	2011	2010
Amounts recognized in Statement of Financial Position consist of:						
Current liabilities	$ --	$ --	$ (6,137)	$ (3,506)	$ (468)	$ (44)
Noncurrent liabilities	(86,211)	(6,146)	(42,233)	(40,816)	(8,762)	(8,247)
Total	$ (86,211)	$ (6,146)	$ (48,370)	$ (44,322)	$ (9,230)	$ (8,291)
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss/(gain)	$ 34,781	$ (43,544)	$ 8,038	$ 5,095	$ 282	$ (820)
Prior service cost	(19,721)	(21,701)	--	--	--	--
Total	$ 15,060	$ (65,245)	$ 8,038	$ 5,095	$ 282	$ (820)

PUGET ENERGY	QUALIFIED PENSION BENEFITS			
			SUCCESSOR	PREDECESSOR
(DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2011	YEAR ENDED DECEMBER 31, 2010	FEBRUARY 6, 2009 – DECEMBER 31, 2009	JANUARY 1, 2009 – FEBRUARY 5, 2009
Components of net periodic benefit cost:				
Service cost	$ 15,822	$ 16,089	$ 12,469	$ 1,090
Interest cost	26,263	27,975	25,912	2,302
Expected return on plan assets	(35,344)	(32,941)	(27,583)	(3,585)
Amortization of prior service cost/(credit)	(1,980)	(165)	--	95
Amortization of net loss	--	70	--	269
Net periodic benefit cost	$ 4,761	$ 11,028	$ 10,798	$ 171

PUGET ENERGY	SERP PENSION BENEFITS			
	SUCCESSOR			PREDECESSOR
(DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2011	YEAR ENDED DECEMBER 31, 2010	FEBRUARY 6, 2009 – DECEMBER 31, 2009	JANUARY 1, 2009 – FEBRUARY 5, 2009
Components of net periodic benefit cost:				
Service cost	$ 1,241	$ 1,024	$ 951	$ 89
Interest cost	2,192	2,165	2,178	193
Amortization of prior service cost	--	--	--	51
Amortization of net loss/(gain)	360	--	--	74
Net periodic benefit cost	$ 3,793	$ 3,189	$ 3,129	$ 407

PUGET ENERGY	Other Benefits			
			Successor	Predecessor
(Dollars in Thousands)	Year Ended December 31, 2011	Year Ended December 31, 2010	February 6, 2009 – December 31, 2009	January 1, 2009 – February 5, 2009
Components of net periodic benefit cost:				
Service cost	$ 113	$ 106	$ 114	$ 11
Interest cost	806	880	894	89
Expected return on plan assets	(502)	(510)	(379)	(37)
Amortization of prior service cost	--	--	--	7
Amortization of net loss/(gain)	(46)	(67)	--	(15)
Amortization of transition obligation	--	--	--	4
Net periodic benefit cost	$ 371	$ 409	$ 629	$ 59

PUGET ENERGY	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2011	2010	2011	2010	2011	2010
Other changes (pre-tax) in plan assets and **benefit obligations recognized in other comprehensive income:**						
Net loss/(gain)	$ 78,324	$ 9,791	$ 3,302	$ 3,663	$ 1,056	$ 236
Amortization of net loss/(gain)	--	(70)	(360)	--	46	67
Prior service credit	--	(21,866)	--	--	--	--
Amortization of prior service credit	1,980	165	--	--	--	--
Total change in other comprehensive income for year	$ 80,304	$ (11,980)	$ 2,942	$ 3,663	$ 1,102	$ 303

The estimated net/(loss) gain and prior service/(cost) credit for the pension plans that will be amortized from accumulated OCI into net periodic benefit cost in 2012 are $(0.6) million and $2.0 million, respectively. The estimated net (loss)/gain and prior service (cost)/credit for the SERP that will be amortized from accumulated OCI into net periodic benefit cost in 2012 are $(0.7) million and zero, respectively. The estimated net (loss)/gain, prior service cost/(credit) and transition/(obligation) asset for the other postretirement plans that will be amortized from accumulated OCI into net periodic benefit cost in 2012 are immaterial. The following tables summarize PSE's change in benefit obligation, change in plan assets, net periodic benefit cost and other changes in OCI for the years ended December 31, 2011 and 2010:

PUGET SOUND ENERGY	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2011	2010	2011	2010	2011	2010
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 532,615	$ 504,786	$ 44,322	$ 39,152	$ 16,579	$ 15,953
Service cost	15,822	16,089	1,241	1,024	113	106
Interest cost	26,263	27,975	2,192	2,165	807	880
Amendment	--	(21,866)	--	--	--	--
Actuarial loss/(gain)	18,485	32,163	4,467	3,663	384	867
Benefits paid	(27,188)	(26,532)	(2,687)	(1,682)	(1,855)	(2,030)
Medicare part D subsidiary received	--	--	--	--	408	803
Curtailment loss/(gain)	--	--	(1,165)[1]	--	--	--
Benefit obligation at end of period	$ 565,997	$ 532,615	$ 48,370	$ 44,322	$ 16,436	$ 16,579

1 *A curtailment gain was recognized in OCI due to the plan amendment that ceased SERP benefits for non-officers still in the plan as of December 31, 2011.*

PUGET SOUND ENERGY	QUALIFIED PENSION BENEFITS		SERP PENSION BENEFITS		OTHER BENEFITS	
(DOLLARS IN THOUSANDS)	2011	2010	2011	2010	2011	2010
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 526,469	$ 485,689	$ --	$ --	$ 8,288	$ 8,790
Actual return on plan assets	(24,495)	55,312	--	--	(170)	1,140
Employer contribution	5,000	12,000	2,687	1,682	943	388
Benefits paid	(27,188)	(26,532)	(2,687)	(1,682)	(1,855)	(2,030)
Fair value of plan assets at end of period	$ 479,786	$ 526,469	$ --	$ --	$ 7,206	$ 8,288
Funded status at end of period	$ (86,211)	$ (6,146)	$ (48,370)	$ (44,322)	$ (9,230)	$ (8,291)

PUGET SOUND ENERGY	QUALIFIED PENSION BENEFITS		SERP PENSION BENEFITS		OTHER BENEFITS	
(DOLLARS IN THOUSANDS)	2011	2010	2011	2010	2011	2010
Amounts recognized in Statement of Financial Position consist of:						
Current liabilities	$ --	$ --	$ (6,137)	$ (3,506)	$ (468)	$ (44)
Noncurrent liabilities	(86,211)	(6,146)	(42,233)	(40,816)	(8,762)	(8,247)
Total	$ (86,211)	$ (6,146)	$ (48,370)	$ (44,322)	$ (9,230)	$ (8,291)
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss/(gain)	$ 264,098	$ 187,240	$ 13,878	$ 11,770	$ (2,955)	$ (4,492)
Prior service cost/(credit)	(15,671)	(17,245)	305	867	72	134
Transition obligations	--	--	--	--	50	100
Total	$ 248,427	$ 169,995	$ 14,183	$ 12,637	$ (2,833)	$ (4,258)

PUGET SOUND ENERGY	QUALIFIED PENSION BENEFITS			SERP PENSION BENEFITS			OTHER BENEFITS		
(DOLLARS IN THOUSANDS)	2011	2010	2009	2011	2010	2009	2011	2010	2009
Components of net periodic benefit cost:									
Service cost	$ 15,822	$ 16,089	$ 14,141	$ 1,241	$ 1,024	$ 1,068	$ 113	$ 106	$ 125
Interest cost	26,263	27,975	27,734	2,192	2,165	2,315	806	880	960
Expected return on plan assets	(44,128)	(43,892)	(43,453)	--	--	--	(502)	(509)	(455)
Amortization of prior service cost/(credit)	(1,573)	548	1,134	563	562	616	63	132	83
Amortization of net loss/(gain)	10,250	7,325	3,702	1,194	769	886	(481)	(553)	(460)
Amortization of transition obligation	--	--	--	--	--	--	50	50	50
Net periodic benefit cost	$ 6,634	$ 8,045	$ 3,258	$ 5,190	$ 4,520	$ 4,885	$ 49	$ 106	$ 303

PUGET SOUND ENERGY	QUALIFIED PENSION BENEFIT		SERP PENSION BENEFITS		OTHER BENEFITS	
(DOLLARS IN THOUSANDS)	2011	2010	2011	2010	2011	2010
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:						
Net loss/(gain)	$ 87,108	$ 20,743	$ 3,302	$ 3,663	$ 1,056	$ 236
Amortization of net (loss)/gain	(10,250)	(7,325)	(1,194)	(769)	481	553
Prior service cost/(credit)	--	(21,867)	--	--	--	--
Amortization of prior service cost/(credit)	1,573	(546)	(562)	(562)	(62)	(132)
Amortization of transition obligation	--	--	--	--	(50)	(50)
Total change in other comprehensive income for year	$ 78,431	$ (8,995)	$ 1,546	$ 2,332	$ 1,425	$ 607

The estimated net (loss)/gain and prior service (cost)/credit for the pension plans that will be amortized from accumulated OCI into net periodic benefit cost in 2012 are $(14.9) million and $1.6 million, respectively. The estimated net loss/(gain) and prior service (cost)/credit for the SERP that will be amortized from accumulated OCI into net periodic benefit cost in 2012 are $(1.4) million and $(0.3) million, respectively. The estimated net (loss)/gain for the other postretirement plan that will be amortized from accumulated OCI into net periodic benefit cost in 2012 is $0.2 million and prior service (cost)/credit and transition (obligation)/asset for the other postretirement plans are immaterial.

The aggregate expected contributions by the Company to fund the retirement plan, SERP and the other postretirement plans for the year ending December 31, 2012 are expected to be at least $22.8 million, $6.1 million and $0.9 million, respectively.

As a result of the Patient Protection and Affordable Care Act of 2010, PSE recorded a one-time tax expense of $0.8 million during the three months ended March 31, 2010, related to a Medicare D subsidy that PSE receives. These subsidies have been non-taxable in the past and will be subject to federal income taxes after 2012 as a result of the legislation.

As part of PSE's contract with the International Brotherhood of Electrical Workers (IBEW) Local 77 union, which took effect September 1, 2010, the benefit calculation formula changed for Company employees covered by the contract. IBEW represented employees hired after August 31, 2010 and employees not vested in a plan benefit as of July 31, 2010 participate in the cash balance formula of the retirement program, with any accrued benefit converted to a beginning cash balance account. Employees who were vested in a plan benefit as of July 31, 2010 had a choice to convert to the cash balance formula or remain on a final average earnings formula based on qualified pay and years of service. All employees accruing benefits under the cash balance formula receive the same investment plan match and Company contribution. Effective December 1, 2010, the IBEW represented employees who accrue benefits under the cash balance formula receive a higher matching contribution and an additional Company contribution as compared to IBEW represented employees who are covered by the final average earnings formula. These are the same formulas applied to non-union represented employees. IBEW represented employees who were rehired after August 31, 2010, will accrue future benefits under the cash balance formula and will be able to elect to convert their prior benefits to the cash balance formula. As a result of these changes to the IBEW contract, approximately 88.0% of the employees are in the cash balance formula and approximately 12.0% of the employees are in the final average earnings formula.

Assumptions

In accounting for pension and other benefit obligations and costs under the plans, the following weighted-average actuarial assumptions were used by the Company:

	Qualified Pension Benefits			SERP Pension Benefits			Other Benefits		
Benefit Obligation Assumptions	2011	2010	2009	2011	2010	2009	2011	2010	2009
Discount rate [1]	4.75%	5.15%	5.75%	4.75%	5.15%	5.75%	4.75%	5.15%	5.75%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Medical trend rate	--	--	--	--	--	--	7.50%	8.00%	7.50%
Benefit Cost Assumptions									
Discount rate	5.15%	5.75%	6.50% [2]	5.15%	5.75%	6.50% [2]	5.15%	5.75%	6.50% [2]
Rate of plan assets	7.75%	8.00%	8.25%	--	--	--	7.80%	7.80%	7.60%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Medical trend rate	--	--	--	--	--	--	8.00%	8.50%	9.00%

1 *The Company calculates the present value of the pension liability using a discount rate of 4.75% which represents the single-rate equivalent of the AA rated corporate bond yield curve.*

2 *6.50% is the benefit cost discount rate used by Puget Energy. 6.20% is the benefit cost discount rate use by PSE. The discount rates for the net periodic costs for Puget Energy and PSE were different because of the discount rates in effect as of February 5, 2009, the date of the merger of Puget Energy with Puget Holdings.*

The assumed medical inflation rate used to determine benefit obligations is 7.5% in 2012 grading down to 4.90% in 2013. A 1.0% change in the assumed medical inflation rate would have the following effects:

	2011		2010	
(Dollars in Thousands)	1% Increase	1% Decrease	1% Increase	1% Decrease
Effect on post-retirement benefit obligation	$ 97	$ 85	$ 97	$ 85
Effect on service and interest cost components	5	4	6	5

The Company has selected the expected return on plan assets based on a historical analysis of rates of return and the Company's investment mix, market conditions, inflation and other factors. The expected rate of return is reviewed annually based on these factors. The Company's accounting policy for calculating the market-related value of assets for the Company's retirement plan is as follows. PSE market-related value of assets is based on a five-year smoothing of asset gains/losses measured from the expected return on market-related assets. This is a calculated value that recognizes changes in fair value in a systematic and rational manner over five years. The same manner of calculating market-related value is used for all classes of assets, and is applied consistently from year to year.

Puget Energy's pension and other postretirement benefits income or costs depend on several factors and assumptions, including plan design, timing and amount of cash contributions to the plan, earnings on plan assets, discount rate, expected long-term rate of return, mortality and health care costs trends. Changes in any of these factors or assumptions will affect the amount of income or expense that Puget Energy records in its financial statements in future years and its projected benefit obligation. Puget Energy has selected an expected return on plan assets based on a historical analysis of rates of return and Puget Energy's investment mix, market conditions, inflation and other factors. As required by merger accounting rules, market-related value was reset to market value effective with the merger.

The discount rates were determined by using market interest rate data and the weighted-average discount rate from Citigroup Pension Liability Index Curve. The Company also takes into account in determining the discount rate the expected changes in market interest rates and anticipated changes in the duration of the plan liabilities.

The aggregate expected contributions and payments by the Company to fund the retirement plan, SERP and the other postretirement plans for the year ending December 31, 2012 are expected to be at least $22.8 million, $6.1 million and $0.9 million, respectively.

PLAN BENEFITS

The expected total benefits to be paid under the qualified pension plans for the next five years and the aggregate total to be paid for the five years thereafter are as follows:

(DOLLARS IN THOUSANDS)	2012	2013	2014	2015	2016	2017-2021
Total benefits	$ 47,100	$ 37,300	$ 37,000	$ 38,000	$ 38,400	$ 208,800

The expected total benefits to be paid under the SERP for the next five years and the aggregate total to be paid for the five years thereafter are as follows:

(DOLLARS IN THOUSANDS)	2012	2013	2014	2015	2016	2017-2021
Total benefits	$ 6,137	$ 1,889	$ 3,492	$ 3,284	$ 3,328	$ 18,652

The expected total benefits to be paid under the other benefits for the next five years and the aggregate total to be paid for the five years thereafter are as follows:

(DOLLARS IN THOUSANDS)	2012	2013	2014	2015	2016	2017-2021
Total benefits	$ 1,354	$ 1,315	$ 1,259	$ 1,198	$ 1,231	$ 6,453
Total benefits without Medicare Part D subsidy	$ 1,778	$ 1,770	$ 1,739	$ 1,700	$ 1,652	$ 7,476

PLAN ASSETS

Plan contributions and the actuarial present value of accumulated plan benefits are prepared based on certain assumptions pertaining to interest rates, inflation rates and employee demographics, all of which are subject to change. Due to uncertainties inherent in the estimations and assumptions process, changes in these estimates and assumptions in the near term may be material to the financial statements.

The Company has a Retirement Plan Committee that establishes investment policies, objectives and strategies designed to balance expected return with a prudent level of risk. All changes to the investment policies are reviewed and approved by the Retirement Plan Committee prior to being implemented.

The Retirement Plan Committee invests trust assets with investment managers who have historically achieved above-median long-term investment performance within the risk and asset allocation limits that have been established. Interim evaluations are routinely performed with the assistance of an outside investment consultant. To obtain the desired return needed to fund the pension benefit plans, the Retirement Plan Committee has established investment allocation percentages by asset classes as follows:

	Allocation		
Asset Class	Minimum	Target	Maximum
Domestic large cap equity	25%	32%	40%
Domestic small cap equity	0%	10%	15%
Non-U.S. equity	10%	20%	30%
Tactical asset allocation	0%	5%	10%
Fixed income	15%	23%	30%
Real estate	0%	0%	10%
Absolute return	5%	10%	15%
Cash	0%	0%	5%

PLAN FAIR VALUE MEASUREMENTS

Effective December 31, 2009, ASC 715, "Compensation – Retirement Benefits" (ASC 715) directs companies to provide additional disclosures about plan assets of a defined benefit pension or other postretirement plan. The objectives of the disclosures are to disclose the following: (1) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies; (2) major categories of plan assets; (3) inputs and valuation techniques used to measure the fair value of plan assets; (4) effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and (5) significant concentrations of risk within plan assets.

In September 2009, the FASB issued ASU 2009-12, "Fair Value Measurements and Disclosures: Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent)." The standard allows the reporting entity, as a practical expedient, to measure the fair value of investments that do not have readily determinable fair values on the basis of the net asset value per share of the investment if the net asset value of the investment is calculated in a matter consistent with ASC 946, "Financial Services – Investment Companies." The standard requires disclosures about the nature and risk of the investments and whether the investments are probable of being sold at amounts different from the net asset value per share.

The following table sets forth by level, within the fair value hierarchy, the qualified pension plan assets that were accounted for at fair value on a recurring basis as of December 31, 2011 and 2010:

	Recurring Fair Value Measures As of December 31, 2011				Recurring Fair Value Measures As of December 31, 2010			
(Dollars in Thousands)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Equities:								
Non-US equity [1]	$ 48,382	$ 42,132	$ --	$ 90,514	$ 54,298	$ 52,418	$ --	$ 106,716
Domestic large cap equity [2]	124,303	29,547	--	153,850	144,431	28,376	--	172,807
Domestic small cap equity [3]	45,650	--	--	45,650	55,750	--	--	55,750
Total equities	218,335	71,679	--	290,014	254,479	80,794	--	335,273
Tactical asset allocation [4]	--	26,922	--	26,922	--	29,566	--	29,566
Fixed income securities [5]	106,573	580	--	107,153	102,314	1,982	--	104,296
Absolute return [6]	--	--	45,319	45,319	--	--	48,100	48,100
Cash and cash equivalents [7]	--	9,015	--	9,015	--	6,737	--	6,737
Subtotal	$ 324,908	$ 108,196	$ 45,319	$ 478,423	$ 356,793	$ 119,079	$ 48,100	$ 523,972
Net receivables				1,088				2,272
Accrued income				275				225
Total assets				$ 479,786				$ 526,469

1 *Non – US Equity investments are comprised of a (1) mutual fund; and a (2) commingled fund. The investment in the mutual fund is valued using quoted market prices multiplied by the number of shares owned as of December 31, 2011. The investment in the commingled fund is valued at the net asset value per share multiplied by the number of shares held as of December 31, 2011.*

2 *Domestic large cap equity investments are comprised of (1) common stock, and a (2) commingled fund. Investments in common stock are valued using quoted market prices multiplied by the number of shares owned as of December 31, 2011. The investment in the commingled fund is valued at the net asset value per share multiplied by the number of shares held as of December 31, 2011.*

3 *Domestic small cap equity investments are comprised of common stock and are valued using quoted market prices multiplied by the number of shares owned as of December 31, 2011.*

4 *The tactical asset allocation investment is compromised of a commingled fund, which is valued at the net asset value per share multiplied by the number of shares held as of the measurement date.*

5 *Fixed income securities consist of a mutual fund and corporate bonds. The investment in the mutual fund is valued using quoted market prices multiplied by the number of shares owned as of December 31, 2011. The corporate bonds are valued using various valuation techniques such as matrix pricing.*

6 *As of December 31, 2011 absolute return investments consist of two partnerships. The partnerships are valued using the financial reports as of December 31, 2011. These investments are a Level 3 under ASC 820 because the significant valuation inputs are primarily internal to the partnerships with little third party involvement.*

7 *The investment consists of a money market fund, which is valued at the net asset value per share of $1.00 per unit as of December 31, 2011. The money market fund invests primarily in commercial paper, notes, repurchase agreements, and other evidences of indebtedness which are payable on demand or which have a maturity date not exceeding thirteen months from the date of purchase.*

LEVEL 3 ROLL-FORWARD

The following table sets forth a reconciliation of changes in the fair value of the plan's Level 3 assets for the years ended December, 31, 2011 and 2010:

	As of December 31, 2011			As of December 31, 2010		
(Dollars in Thousands)	Partnership	Mutual Funds	Total	Partnership	Mutual Funds	Total
Balance at beginning of year	$ 35,481	$ 12,619	$ 48,100	$ 23,214	$ 23,012	$ 46,226
Additional investments	11,635	--	11,635	10,473	--	10,473
Distributions	--	(11,635)	(11,635)	--	(11,716)	(11,716)
Realized losses on distributions	--	(290)	(290)	--	(1,370)	(1,370)
Unrealized gains relating to instruments still held at the reporting date	(1,797)	599	(1,198)	1,794	2,693	4,487
Transferred out of level 3 [1]	--	(1,293)	(1,293)	--	--	--
Balance at end of year	$ 45,319	$ --	$ 45,319	$ 35,481	$ 12,619	$ 48,100

1 *The plan had no transfers between level 2 and level 1 during the years ended December 31, 2011 or 2010.*

The following table sets forth by level, within the fair value hierarchy, the Other Benefits plan assets which consist of insurance benefits for retired employees, at fair value as of December 31, 2011 and 2010:

(Dollars in Thousands)	Recurring Fair Value Measures as of December 31, 2011			Recurring Fair Value Measures as of December 31, 2010		
	Level 1	Level 2	Total	Level 1	Level 2	Total
Assets:						
Mutual fund [1]	$ 7,137	$ --	$ 7,137	$ 8,115	$ --	$ 8,115
Cash equivalents [2]	--	130	130	--	173	173
Total assets	$ 7,137	$ 130	$ 7,267	$ 8,115	$ 173	$ 8,288

1 *This is a publicly traded balanced mutual fund. The fund seeks regular income, conservation of principal, and an opportunity for long-term growth of principal and income. The fair value is determined by taking the number of shares owned by the plan, and multiplying by the market price as of December 31, 2011.*

2 *This consists of a deposit fund and a money market fund. The fair value of the deposit fund is calculated by using the financial reports available as of December 31, 2011. The money market fund investments are valued at the net asset value per share of $1.00 per unit as of December 31, 2011. The money market fund invests primarily in commercial paper, notes, repurchase agreements, and other evidences of indebtedness which are payable on demand or which have a maturity date not exceeding thirteen months from the date or purchase.*

(15) Stock-based Compensation Plans

Prior to the merger on February 6, 2009, the Company granted equity awards, including stock awards, performance awards, stock options and restricted stock to officers and key employees of the Company under the Company's Long-Term Incentive Plan (LTI Plan), approved by the shareholders in 2005. Any shares awarded were either purchased on the open market or were a new issuance. With the completion of the merger, all shares outstanding under the LTI Plan were fully vested and settled in cash to plan participants. Puget Energy paid and recognized $14.5 million of merger expense in connection to the vesting of the LTI Plan shares.

Performance Share Grants

The Company generally awarded performance share grants annually under the LTI Plan to key employees which vested at the end of three years. The number of shares awarded and the amount of expense recorded depended on Puget Energy's performance as compared to other companies and service quality indices for customer service. Compensation expense related to performance share grants was $9.6 million for 2009.

Performance shares activity from December 31, 2008 to February 5, 2009 was as follows:

Predecessor	Number of Shares	Weighted-Average Fair Value Per Share
Total at December 31, 2008:	244,390	$ 25.65
Granted	--	--
Vested	(244,390)	25.65
Forfeited	--	--
Performance Shares Outstanding at February 5, 2009:	--	$ --

Plan participants meeting the Company's stock ownership guidelines could elect to be paid up to 50.0% of the share award in cash. The portion of the performance share grants that could be paid in cash was classified and accounted for as a liability. As a result, the compensation expense of these liability awards was recognized over the performance period based on the fair value (i.e. cash value) of the award, and was periodically updated based on expected ultimate cash payout. Compensation cost recognized during the performance period for the liability portion of the performance grants was based on the closing price of the Company's common stock on the date of measurement and the number of months of service rendered during the period. The equity portion was valued based on the closing price of the Company's common stock on the grant date. In connection with the completion of the merger in 2009, all performance shares vested and the Company paid and recognized $9.6 million recorded in merger and related costs for such shares.

STOCK OPTIONS

In 2002, Puget Energy's Board of Directors granted 40,000 stock options under the LTI Plan and an additional 260,000 options outside the LTI Plan (for a total of 300,000 non-qualified stock options) to the former President and Chief Executive Officer. These options could be exercised at the grant date market price of $22.51 per share and vested annually over four and five years, respectively. The fair value of the stock option award was estimated at $3.33 per share on the date of grant using the Black-Scholes option valuation model. The options were cancelled at the time of the merger and $2.3 million was paid in cash to the former President and Chief Executive Officer based on the terms of the merger agreement.

RESTRICTED STOCK

Restricted stock activity for the year ended December 31, 2009 was as follows:

PREDECESSOR	NUMBER OF SHARES	WEIGHTED-AVERAGE FAIR VALUE PER SHARE
Restricted Stock Outstanding at December 31, 2008:	227,643	$ 24.64
Granted	--	--
Vested	(227,643)	24.64
Forfeited	--	--
Restricted Stock Outstanding at February 5, 2009:	--	$ --

Compensation expense related to the restricted shares was $2.2 million for 2009.

NON-EMPLOYEE DIRECTOR STOCK PLAN

Prior to February 6, 2009, the Company had a non-employee director stock plan for all non-employee directors of Puget Energy and PSE. An amended and restated plan was approved by shareholders in 2005. Under the plan, non-employee directors received a portion of their quarterly retainer fees in Puget Energy stock except that 100.0% of quarterly retainers were paid in Puget Energy stock until the director held a number of shares equal in value to two years of their retainer fees. Directors could choose to continue to receive their entire retainer in Puget Energy stock. The compensation expense related to the director stock plan was $0.4 million in 2009. The director stock plan was terminated on February 6, 2009 by action of the Board of Directors upon completion of the merger and outstanding shares thereunder were settled.

(16) Income Taxes

The details of income tax (benefit) expense are as follows:

PUGET ENERGY (DOLLARS IN THOUSANDS)	SUCCESSOR YEAR ENDED DECEMBER 31, 2011	SUCCESSOR YEAR ENDED DECEMBER 31, 2010	SUCCESSOR FEBRUARY 6, 2009 – DECEMBER 31, 2009	PREDECESSOR JANUARY 1, 2009 – FEBRUARY 5, 2009
Charged to operating expenses:				
Current:				
Federal	$ 785	$ 42,061	$ (161,087)	$ 10,185
State	(50)	385	(988)	87
Deferred:				
Federal	32,706	(38,717)	244,116	(1,275)
State	319	(1,248)	--	--
Total income tax expense	$ 33,760	$ 2,481	$ 82,041	$ 8,997

PUGET SOUND ENERGY	YEAR ENDED DECEMBER 31,		
(DOLLARS IN THOUSANDS)	2011	2010	2009
Charged to operating expenses:			
Current:			
Federal	$ 653	$ 32,331	$ (126,156)
State	--	385	(901)
Deferred:			
Federal	76,369	(31,346)	194,701
State	1,095	(1,248)	--
Total income tax expense	$ 78,117	$ 122	$ 67,644

The following reconciliation compares pre-tax book income at the federal statutory rate of 35.0% to the actual income tax expense in the Statements of Income:

	SUCCESSOR			PREDECESSOR
PUGET ENERGY (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2011	YEAR ENDED DECEMBER 31, 2010	FEBRUARY 6, 2009 – DECEMBER 31, 2009	JANUARY 1, 2009 – FEBRUARY 5, 2009
Income taxes at the statutory rate	$ 54,968	$ 11,477	$ 89,620	$ 7,613
Increase (decrease):				
Production tax credit	(23,310)	(19,972)	(13,871)	(5,870)
AFUDC excluded from taxable income	(22,861)	(9,970)	(5,326)	(1,771)
Capitalized interest	17,592	8,244	5,028	914
Utility plant differences	5,849	6,162	4,323	1,472
Tenaska gas contract	7,094	5,889	3,049	1,429
Transaction costs	--	--	201	5,544
Other - net	(5,572)	651	(983)	(334)
Total income tax expense	$ 33,760	$ 2,481	$ 82,041	$ 8,997
Effective tax rate	21.5%	7.6%	32.0%	41.4%

PUGET SOUND ENERGY	YEAR ENDED DECEMBER 31,		
(DOLLARS IN THOUSANDS)	2011	2010	2009
Income taxes at the statutory rate	$ 98,783	$ 9,176	$ 79,414
Increase (decrease):			
Production tax credit	(23,310)	(19,972)	(19,741)
AFUDC excluded from taxable income	(22,861)	(9,970)	(7,097)
Capitalized interest	17,592	8,244	5,942
Utility plant differences	5,849	6,162	5,795
Tenaska gas contract	7,094	5,889	4,478
Other - net	(5,030)	593	(1,147)
Total income tax expense	$ 78,117	$ 122	$ 67,644
Effective tax rate	27.7%	0.5%	29.8%

The Company's deferred tax liability at December 31, 2011 and 2010 is composed of amounts related to the following types of temporary differences:

PUGET ENERGY (DOLLARS IN THOUSANDS)	AT DECEMBER 31, 2011	2010
Utility plant and equipment	$ 1,200,796	$ 1,099,857
Fair value of debt instruments	90,535	92,661
Regulatory asset for income taxes	62,304	73,337
Pensions and other compensation	14,146	46,084
Storm damage	30,556	36,286
Other deferred tax liabilities	85,367	106,714
Subtotal deferred tax liabilities	1,483,704	1,454,939
Net operating loss carryforward	(165,088)	(168,463)
Fair value of derivative instruments	(96,374)	(116,320)
Production tax credit carryforward	(89,226)	(60,613)
Other deferred tax assets	(81,194)	(65,018)
Subtotal deferred tax assets	(431,882)	(410,414)
Total	$ 1,051,822	$ 1,044,525

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	AT DECEMBER 31, 2011	2010
Utility plant and equipment	$ 1,200,796	$ 1,099,857
Regulatory asset for income taxes	61,344	73,337
Storm damage	30,556	36,286
Other deferred tax liabilities	81,928	85,206
Subtotal deferred tax liabilities	1,374,624	1,294,686
Fair value of derivative instruments	(92,502)	(85,394)
Production tax credit carryforward	(89,226)	(60,613)
Net operating loss carryforward	(50,281)	(105,140)
Pensions and other compensation	(63,234)	(31,312)
Other deferred tax assets	(75,946)	(57,925)
Subtotal deferred tax assets	(371,189)	(340,384)
Total	$ 1,003,435	$ 954,302

The above amounts have been classified in the Balance Sheets as follows:

PUGET ENERGY (DOLLARS IN THOUSANDS)	AT DECEMBER 31 2011	2010
Current deferred taxes	$ (101,934)	$ (83,086)
Non-current deferred taxes	1,153,756	1,127,611
Total	$ 1,051,822	$ 1,044,525

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	AT DECEMBER 31 2011	2010
Current deferred taxes	$ (112,204)	$ (80,215)
Non-current deferred taxes	1,115,639	1,034,517
Total	$ 1,003,435	$ 954,302

The Company calculates its deferred tax assets and liabilities under ASC 740, "Income Taxes" (ASC 740). ASC 740 requires recording deferred tax balances, at the currently enacted tax rate, on assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes. The utilization of deferred tax assets requires sufficient taxable income in the future years. ASC 740 requires a valuation allowance on deferred tax assets when it is more likely than not that the deferred tax asset will not be realized. The Company's PTC carryforwards expire from 2026 through 2031. The Company's net operating loss carryforwards expire from 2029 through 2030.

For ratemaking purposes, deferred taxes are not provided for certain temporary differences. PSE has established a regulatory asset for income taxes recoverable through future rates related to those temporary differences for which no deferred taxes have been provided, based on prior and expected future ratemaking treatment.

The Company accounts for uncertain tax position under ASC 740, which clarifies the accounting for uncertainty in income taxes recognized in the financial statements. ASC 740 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, a tax position should only be recognized when it is more likely than not, based on technical merits, that the position will be sustained upon challenge by the taxing authorities and taken by management to the court of last resort. Second, a tax position that meets the recognition threshold should be measured at the largest amount that has a greater than 50.0% likelihood of being sustained.

As of December 31, 2011 and 2010, the Company had no material unrecognized tax benefits. As a result, no interest or penalties were accrued for unrecognized tax benefits during the year.

For ASC 740 purposes, the Company has open tax years from 2006 through 2011. The Company is under audit by the IRS for tax years 2006 and 2009. The Company classifies interest as interest expense and penalties as other expense in the financial statements.

(17) Litigation

RESIDENTIAL EXCHANGE

The Northwest Power Act, through the Residential Exchange Program (REP), provides access to the benefits of low-cost federal hydroelectric power to residential and small farm customers of regional utilities, including PSE. The program is administered by the Bonneville Power Administration (the BPA). Pursuant to agreements (including settlement agreements) between the BPA and PSE, the BPA has provided payments of REP benefits to PSE, which PSE has passed through to its residential and small farm customers in the form of electricity bill credits.

In 2007, the U.S. Court of Appeals for the Ninth Circuit ruled that REP agreements of the BPA with PSE and a number of other investor-owned utilities were inconsistent with the Northwest Power Act. Since that time, those investor-owned utilities, including PSE, the BPA and other parties have been involved in ongoing litigation at the Ninth Circuit relating to the amount of REP benefits paid to utilities, including PSE, for the period fiscal year 2002 through fiscal year 2011 and the amount of REP benefits to be paid going forward.

In July 2011, the BPA, PSE and a number of other parties entered into a settlement agreement that by its terms if upheld in their entirety would resolve the disputes between BPA and PSE regarding REP benefits paid for the period fiscal year 2002-fiscal year 2011. In October 2011, certain other parties challenged BPA decisions with regard to its entering into this most recent settlement agreement. Pending disposition of this challenge, the other pending Ninth Circuit litigation regarding REP benefits for the period fiscal year 2002 through fiscal year 2011 has been stayed by the Ninth Circuit.

Due to the pending and ongoing proceedings, PSE is unable to reasonably estimate any amounts of REP payments – either to be recovered by the BPA or to be paid for any future periods to PSE – and is unable to determine the impact, if any, these proceedings and litigation may have on PSE. However, it is unlikely that any unfavorable outcome would have a material adverse effect on PSE because REP benefits received by PSE are passed through to PSE's residential and small farm customers.

PACIFIC NORTHWEST REFUND PROCEEDING

In October 2000, PSE filed a complaint with the FERC (Docket No. EL01-10) against “all jurisdictional sellers” in the Pacific Northwest seeking prospective price caps consistent with any result the FERC ordered for the California markets. The FERC issued an order including price caps in July 2001, and PSE moved to dismiss the proceeding. In response to PSE’s motion, various entities intervened and sought to convert PSE’s complaint into one seeking retroactive refunds in the Pacific Northwest. The FERC rejected that effort, after holding what the FERC referred to as a “preliminary evidentiary hearing” before an administrative law judge. On October 3, 2011, after appellate reviews, the FERC issued an Order on Remand and set the matter for hearing before an administrative law judge, but first requiring the parties to engage in settlement talks that began in the fall of 2011 and are ongoing. As such, the hearing date itself is not known. PSE has not taken any reserve on this matter as it believes it has no exposure, and intends to vigorously defend its position but is unable to predict the outcome of this matter.

OTHER PROCEEDINGS

The Company is also involved in litigation relating to claims arising out of its operations in the normal course of business. The Company has recorded a total of $3.8 million and $3.1 million relating to these claims as of December 31, 2011 and 2010, respectively.

(18) Variable Interest Entities

In accordance with ASC 810, "Consolidation" (ASC 810), a business entity that has a controlling financial interest in a variable interest entity (VIE) should consolidate the VIE in its financial statements. A primary beneficiary of a VIE is the variable interest holder that has both the power to direct matters that significantly impact the activities of the VIE and has the obligation to absorb losses or the right to receive benefits. The Company enters into a variety of contracts for energy with other counterparties and evaluates all contracts to determine if they are variable interests. The Company's variable interests primarily arise through power purchase agreements where it is required to buy all or a majority of generation from a plant at rates set forth in the agreement.

The Company evaluated its power purchase agreements and determined it was not the primary beneficiary of any VIEs. The Company had previously disclosed two potentially significant variable interests in prior periods; both entities were qualifying facilities contracts that expired at the end of 2011. The Company requested information from the relevant entities; however, they refused to provide the necessary information, as they were not required to do so under their contracts. However, if the variable interests had been determined to be VIEs, the Company concluded it would not have been the primary beneficiary of these entities based on available information and it had no exposure to loss on these contracts. For the years ended December 31, 2011, 2010 and 2009, the Company's purchased power expense for these entities was $175.9 million, $190.3 million and $181.2 million, respectively.

(19) Commitments and Contingencies

For the year ended December 31, 2011, approximately 24.2% of the Company's energy output was obtained at an average cost of approximately $0.015 per kilowatt hour (kWh) through long-term contracts with three of the Washington Public Utility Districts (PUDs) that own hydroelectric projects on the Columbia River. The purchase of power from the Columbia River projects is on a pro rata share basis under which the Company pays a proportionate share of the annual debt service, operating and maintenance costs and other expenses associated with each project in proportion to the contractual shares that PSE obtains from that project. In these instances, PSE's payments are not contingent upon the projects being operable; therefore, PSE is required to make the payments even if power is not delivered. These projects are financed through substantially level debt service payments and their annual costs should not vary significantly over the term of the contracts unless additional financing is required to meet the costs of major maintenance, repairs or replacements, or license requirements. The Company's share of the costs and the output of the projects is subject to reduction due to various withdrawal rights of the PUDs and others over the contract lives.

The following table summarizes the Company's estimated payment obligations for power purchases from the Columbia River projects, contracts with other utilities and contracts under non-utility generators under the Public Utility Regulatory Policies Act. These contracts have varying terms and may include escalation and termination provisions.

(DOLLARS IN THOUSANDS)	2012	2013	2014	2015	2016	THEREAFTER	TOTAL
Columbia River projects	$ 72,634	$ 71,336	$ 73,039	$ 74,888	$ 74,407	$ 683,436	$1,049,740
Other utilities	135,481	75,994	52,432	47,982	40,544	264,981	617,414
Non-utility generators	2,814	3,555	4,277	5,227	2,981	--	18,854
Total	$ 210,929	$ 150,885	$ 129,748	$ 128,097	$ 117,932	$ 948,417	$1,686,008

Total purchased power contracts provided the Company with approximately 8.5 million, 8.2 million and 8.3 million megawatt hours (MWh) of firm energy at a cost of approximately $391.8 million, $420.6 million and $363.3 million for the years 2011, 2010 and 2009, respectively.

The Company has natural gas-fired generation facility obligations for natural gas supply amounting to an estimated $33.3 million in 2012. Longer term agreements for natural gas supply amount to an estimated $340.4 million for 2013 through 2029.

PSE enters into short-term energy supply contracts to meet its core customer needs. These contracts are sometimes classified as NPNS, however in most cases recorded at fair value in accordance with ASC 815. Commitments under these contracts are $200.5 million, $92.5 million and $25.2 million in 2012, 2013 and 2014, respectively.

NATURAL GAS SUPPLY OBLIGATIONS

The Company has also entered into various firm supply, transportation and storage service contracts in order to ensure adequate availability of natural gas supply for its firm customers. Many of these contracts, which have remaining terms from less than one year to 34 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. The Company contracts for its long-term natural gas supply on a firm basis, which means the Company has a 100% daily take obligation and the supplier has a 100% daily delivery obligation to ensure service to PSE's customers and generation requirements. The Company incurred demand charges in 2011 for firm natural gas supply, firm transportation service and firm storage and peaking service of $0.1 million, $142.8 million and $6.5 million, respectively. The Company incurred demand charges in 2011 for firm transportation and firm storage service for the natural gas supply for its combustion turbines in the amount of $32.3 million, which is included in the total Company demand charges.

The following table summarizes the Company's obligations for future demand charges through the primary terms of its existing contracts. The quantified obligations are based on the FERC authorized rates, which are subject to change.

DEMAND CHARGE OBLIGATIONS (DOLLARS IN THOUSANDS)	2012	2013	2014	2015	2016	THEREAFTER	TOTAL
Firm transportation service	$ 142,586	$ 138,528	$ 134,357	$ 126,484	$ 122,375	$ 595,779	$ 1,260,109
Firm storage service	8,822	4,134	1,574	1,574	1,574	6,225	23,903
Total	$ 151,408	$ 142,662	$ 135,931	$ 128,058	$ 123,949	$ 602,004	$ 1,284,012

SERVICE CONTRACTS

The following table summarizes the Company's estimated obligations for service contracts through the terms of its existing contracts.

SERVICE CONTRACT OBLIGATIONS (DOLLARS IN THOUSANDS)	2012	2013	2014	2015	2016	THEREAFTER	TOTAL
Energy production service contracts [1]	$ 28,815	$ 24,968	$ 25,873	$ 31,843	$ 10,437	$ 53,669	$ 175,605
Information technology service contracts	22,374	13,951	--	--	--	--	36,325
Automated meter reading system [2]	19,340	20,513	21,161	21,897	14,198	109,069	206,178
Total	$ 70,529	$ 59,432	$ 47,034	$ 53,740	$ 24,635	$ 162,738	$ 418,108

1 *Energy production service contracts include operations and maintenance contracts on Mint Farm, Wild Horse, Goldendale electric generating facility (Goldendale), Hopkins Ridge, Frederickson 1, Sumas and Lower Snake River facilities.*

2 *Automated meter reading system contractual obligation is the service component of the Landis and Gyr contract.*

SURETY BOND

The Company has a self-insurance surety bond in the amount of $3.7 million, which expires on July 1, 2012 and is renewed annually, guaranteeing compliance with the Industrial Insurance Act (workers' compensation) and eight self-insurer's pension bonds totaling $1.2 million.

ENVIRONMENTAL REMEDIATION

The Company is subject to environmental laws and regulations by the federal, state and local authorities and is required to undertake certain environmental investigative and remedial efforts as a result of these laws and regulations. The Company has been named by the Environmental Protection Agency (EPA), the Washington State Department of Ecology and/or other third parties as potentially responsible at several contaminated sites and manufactured gas plant sites. PSE has implemented an ongoing program to test, replace and remediate certain underground storage tanks (UST) as required by federal and state laws. The UST replacement component of this effort is finished, but PSE continues its work remediating and/or monitoring relevant sites. During 1992, the Washington Commission issued orders regarding the treatment of costs incurred by the

Company for certain sites under its environmental remediation program. The orders authorize the Company to accumulate and defer prudently incurred cleanup costs paid to third parties for recovery in rates established in future rate proceedings, subject to Washington Commission review. The Washington Commission consolidated the gas and electric methodological approaches to remediation and deferred accounting in an order issued October 8, 2008. Per the guidance of ASC 450, "Contingencies," the Company reviews its estimated future obligations and adjusts loss reserves quarterly. Management believes it is probable and reasonably estimable that the impact of the potential outcomes of disputes with certain property owners and other potentially responsible parties will result in environmental remediation costs ranging from $39.1 million to $57.3 million for gas and from $8.2 million to $27.9 million for electric. The Company does not consider any amounts within those ranges as being a better estimate and has therefore accrued $39.1 million and $8.2 million for gas and electric, respectively. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties or from customers under a Washington Commission order. For the year ended December 31, 2011, the Company incurred deferred electric and natural gas environmental costs of $9.6 million and $5.5 million, net of insurance proceeds, respectively.

(20) Related Party Transactions

On June 1, 2006, PSE entered into a revolving credit facility with Puget Energy in the form of a Demand Promissory Note (Note). Through the Note, PSE may borrow up to $30.0 million from Puget Energy, subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lowest of the weighted-average interest rate of PSE's outstanding commercial paper interest rate or PSE's senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. At December 31, 2011 and December 31, 2010, the outstanding balance of the Note was $30.0 million and $22.6 million, respectively, and the interest rate was 1.6% and 1.1%, respectively. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements. The $30.0 million credit facility with Puget Energy was unaffected by the merger.

On June 3, 2011, Puget Energy issued $500.0 million of senior secured notes. Macquarie Capital (USA) Inc. acted as a co-manager and underwriter of this issue. Net proceeds of $484.0 million from these notes were used to repay a portion of the outstanding $782.0 million term-loan. Puget Energy's term-loan and credit facility for funding capital expenditures both mature in February 2014, contain similar terms and conditions and are syndicated among numerous committed banks and other financial institutions. One of these banks is Macquarie Bank Limited, which as of December 31, 2011 had commitments of $6.9 million under the term-loan and $50.6 million under the capital expenditure credit facility. Concurrent with the borrowings under these credit agreements, Puget Energy entered into several interest rate swap instruments to hedge volatility associated with these two loans. Two of the swap instruments were entered into with Macquarie Bank Limited with a total notional amount of $444.9 million. On June 3, 2011 Puget Energy settled one of the swaps with a notional amount of $77.4 million, while the other swap instrument, with a notional amount of $367.5 million, remains outstanding as of December 31, 2011.

(21) Fair Value of Intangible Assets

At the time of merger, Puget Energy recorded the fair value of its intangible assets in accordance with ASC 360, "Property, Plant, and Equipment," (ASC 360). The fair value assigned to the power contracts was determined using an income approach comparing the contract rate to the market rate for power over the remaining period of the contracts incorporating nonperformance risk. Management also incorporated certain assumptions related to quantities and market presentation that it believes market participants would make in the valuation. The fair value of the power contracts is amortized as the contracts settle. ASC 360 requires long-lived assets to be tested for impairment on an on-going basis, whenever events or circumstances would more likely than not reduce the fair value of the long-lived assets below its carrying value. One such triggering event is a significant decrease in market price.

Puget Energy completed a valuation and impairment test as of December 31, 2011 for long-term power purchase contracts. The valuation indicated impairment to two of the purchased power contracts, the WNP-3 BPA Exchange Power contract and the Rock Island hydro contract. As of December 31, 2011, the carrying value for the WNP-3 BPA intangible asset contract was $1.9 million but its fair value on a discounted basis was less than zero thereby requiring a full write-off of the intangible asset with a corresponding reduction in the regulatory liability. The carrying value for Rock Island intangible asset contract was $44.9 million and its fair value on a discounted basis was determined to be $9.8 million thereby requiring a $35.1 million write-off of the intangible asset with a corresponding reduction in the regulatory liability.

Puget Energy completed a valuation and impairment test as of December 31, 2010 for long-term power purchase contracts and SO2 emission allowance assets. The carrying value of Puget Energy's power contracts and SO2 emission allowances as of December 31, 2010 was approximately $864.7 million and $7.9 million, respectively. The excess of the carrying value over the fair value of the power contracts was $105.8 million which was written-off against regulatory liabilities at December 31, 2010. The excess of the carrying value over the fair value of the SO2 emissions was $7.9 million which was expensed at December 31, 2010.

(22) Segment Information

Puget Energy operates one business segment referred to as the regulated utility segment. The regulated utility segment includes the account receivables securitization program which was terminated during the merger. Puget Energy's regulated utility operation generates, purchases and sells electricity and purchases, transports and sells natural gas. The service territory of PSE covers approximately 6,000 square miles in the state of Washington.

Non-utility business segment includes two PSE subsidiaries and Puget Energy, and is described as Other. The PSE subsidiaries are a real estate investment and development company and a holding company for a small non-utility wholesale generator which was sold in 2010. Reconciling items between segments are not significant.

Effective February 6, 2009, all merger related fair value adjustments were retained in Puget Energy. Accordingly, only the financial statements of Puget Energy were adjusted to reflect the purchase accounting. Prior to the merger, the business segment financial statements for Puget Energy and PSE were the same.

PUGET ENERGY (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2011 REGULATED UTILITY	OTHER	TOTAL
Revenue	$ 3,319,105	$ (340)	$ 3,318,765
Depreciation and amortization	371,977	1	371,978
Income tax (benefit) expense	91,464	(57,704)	33,760
Operating income	477,730	(2,790)	474,940
Interest charges, net of AFUDC	210,463	131,498	341,961
Net income	228,908	(105,618)	123,290
Total assets	10,648,493	1,736,217	12,384,710
Construction expenditures - excluding equity AFUDC	976,513	--	976,513

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2011 REGULATED UTILITY	OTHER	TOTAL
Revenue	$ 3,319,106	$ 697	$ 3,319,803
Depreciation and amortization	371,977	1	371,978
Income tax expense	78,451	(334)	78,117
Operating income	431,553	(510)	431,043
Interest charges, net of AFUDC	201,467	--	201,467
Net income	204,740	(620)	204,120
Total assets	10,042,263	43,284	10,085,547
Construction expenditures - excluding equity AFUDC	976,513	--	976,513

PUGET ENERGY (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2010 REGULATED UTILITY	OTHER	TOTAL
Revenue	$ 3,121,934	$ 283	$ 3,122,217
Depreciation and amortization	364,205	1	364,206
Income tax (benefit) expense	35,905	(33,424)	2,481
Operating income	310,130	(1,896)	308,234
Interest charges, net of AFUDC	220,922	86,088	307,010
Net income	92,927	(62,616)	30,311
Total assets	10,180,532	1,748,804	11,929,336
Construction expenditures - excluding equity AFUDC	859,091	--	859,091

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2010 REGULATED UTILITY	OTHER	TOTAL
Revenue	$ 3,121,935	$ 282	$ 3,122,217
Depreciation and amortization	364,204	2	364,206
Income tax (benefit) expense	60	62	122
Operating income	207,647	(56)	207,591
Interest charges, net of AFUDC	220,854	--	220,854
Net income	26,358	(263)	26,095
Total assets	9,260,675	50,109	9,310,784
Construction expenditures - excluding equity AFUDC	859,091	--	859,091

	SUCCESSOR FEBRUARY 6, 2009 - DECEMBER 31, 2009		PREDECESSOR JANUARY 1, 2009 - FEBRUARY 5, 2009		YEAR ENDED DECEMBER 31, 2009
PUGET ENERGY (DOLLARS IN THOUSANDS)	REGULATED UTILITY	OTHER	REGULATED UTILITY	OTHER	TOTAL
Revenue	$ 2,921,550	$ 3,598	$ 403,713	$ --	$ 3,328,861
Depreciation and amortization	305,904	39	26,742	--	332,685
Income tax (benefit) expense	113,241	(31,200)	10,537	(1,540)	91,038
Operating income	477,082	(2,219)	55,830	(20,420)	510,273
Interest charges, net of AFUDC	176,858	79,953	16,966	(25)	273,752
Net income	229,973	(55,958)	31,611	(18,855)	186,771
Total assets	10,117,563	1,782,577	8,507,548	87,288	11,900,140
Construction expenditures - excluding equity AFUDC	726,157	--	49,531	--	775,688

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2009 REGULATED UTILITY	OTHER	TOTAL
Revenue	$ 3,325,263	$ 3,238	$ 3,328,501
Depreciation and amortization	332,646	206	332,852
Income tax (benefit) expense	69,890	(2,246)	67,644
Operating income	387,652	(4,517)	383,135
Interest charges, net of AFUDC	202,527	--	202,527
Net income	161,508	(2,256)	159,252
Total assets	8,765,189	51,382	8,816,571
Construction expenditures - excluding equity AFUDC	775,688	--	775,688

SUPPLEMENTAL QUARTERLY FINANCIAL DATA

The following unaudited amounts, in the opinion of the Company, include all adjustments (consisting of normal recurring adjustments) necessary for a fair statement of the results of operations for the interim periods. Quarterly amounts vary during the year due to the seasonal nature of the utility business.

PUGET ENERGY	2011 QUARTER			
(UNAUDITED; DOLLARS IN THOUSANDS)	FIRST	SECOND	THIRD	FOURTH
Operating revenue	$ 1,019,593	$ 732,675	$ 597,776	$ 968,721
Operating income	218,145	114,693	20,663	121,439
Net income (loss)	107,431	5,035	(36,470)	47,294

	2010 QUARTER			
(UNAUDITED; DOLLARS IN THOUSANDS)	FIRST	SECOND	THIRD	FOURTH
Operating revenue	$ 878,206	$ 673,287	$ 622,829	$ 947,895
Operating income	45,403	71,726	(2,184)	193,289
Net income	(19,191)	3,663	(37,899)	83,738

PUGET SOUND ENERGY	2011 QUARTER			
(UNAUDITED; DOLLARS IN THOUSANDS)	FIRST	SECOND	THIRD	FOURTH
Operating revenue	$ 1,019,593	$ 733,364	$ 597,776	$ 969,070
Operating income	190,436	107,380	17,198	116,029
Net income (loss)	103,439	50,913	(9,107)	58,875

	2010 QUARTER			
(UNAUDITED; DOLLARS IN THOUSANDS)	FIRST	SECOND	THIRD	FOURTH
Operating revenue	$ 878,206	$ 673,287	$ 622,829	$ 947,895
Operating income	(4,984)	48,794	(16,593)	180,374
Net income	(38,274)	507	(29,559)	93,421

SCHEDULE I: CONDENSED FINANCIAL INFORMATION OF PUGET ENERGY

PUGET ENERGY
CONDENSED STATEMENTS OF INCOME
(Dollars in Thousands)

	Year Ended December 31, 2011	Year Ended December 31, 2010	Successor February 6, 2009 - December 31, 2009	Predecessor January 1, 2009 - February 5, 2009
Equity in earnings of subsidiary [1]	$ 228,288	$ 92,700	$ 231,978	$ 31,611
Non-utility expense and other	(2,280)	(1,895)	(1,526)	(4)
Merger and related costs	--	--	(2,731)	(20,416)
Other income (deductions):				
Charitable foundation contributions	--	--	(5,000)	--
Unhedged interest rate derivative expense	(28,601)	(7,955)	--	--
Interest income	215	260	240	25
Interest expense	(131,702)	(86,304)	(80,193)	--
Income taxes	57,370	33,505	31,247	1,540
Net income	$ 123,290	$ 30,311	$ 174,015	$ 12,756

[1] *Equity earnings of subsidiary included earnings from PSE of $204.1 million and $26.1 million for the years ended December 31, 2011 and 2010, respectively, and purchase accounting adjustments recorded at Puget Energy for PSE of $24.2 million and $66.6 million for the years ended December 31, 2011 and 2010, respectively.*

See accompanying notes to the consolidated financial statements.

PUGET ENERGY
CONDENSED BALANCE SHEETS
(Dollars in Thousands)

	DECEMBER 31,	
	2011	2010
Assets:		
Investment in subsidiaries [1]	$ 3,314,195	$ 3,063,356
Other property and investments:		
Goodwill	1,656,513	1,656,513
Current assets:		
Cash	6,224	237
Receivables from affiliates [2]	30,291	23,509
Income taxes	--	14,069
Deferred income taxes	8,824	10,516
Total current assets	45,339	48,331
Long-term assets:		
Deferred income taxes	117,110	71,967
Other	13,544	8,267
Total long-term assets	130,654	80,234
Total assets	$ 5,146,701	$ 4,848,434
Capitalization and liabilities:		
Common equity	$ 3,300,923	$ 3,322,912
Long-term debt	1,779,844	1,463,039
Total capitalization	5,080,767	4,785,951
Current liabilities:		
Interest	13,525	4,480
Unrealized loss on derivative instruments	25,210	30,047
Total current liabilities	38,735	34,527
Long-term liabilities:		
Unrealized loss on derivative instruments	27,199	27,956
Total long-term liabilities	27,199	27,956
Total capitalization and liabilities	$ 5,146,701	$ 4,848,434

1 *Investment in subsidiaries for successor include Puget Energy business combination accounting adjustments under ASC 805 that are recorded at Puget Energy.*
2 *Eliminated in consolidation.*

See accompanying notes to the consolidated financial statements.

PUGET ENERGY
CONDENSED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	YEAR ENDED DECEMBER 31, 2011	YEAR ENDED DECEMBER 31, 2010	SUCCESSOR FEBRUARY 6, 2009 - DECEMBER 31, 2009	PREDECESSOR JANUARY 1, 2009 - FEBRUARY 5, 2009
Operating activities:				
Net income	$ 123,290	$ 30,311	$ 174,015	$ 12,756
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Unrealized gain on derivative instruments	33,549	(3,599)	--	--
Deferred income taxes and tax credits – net	(57,151)	(52,364)	(7,886)	--
Equity in earnings of subsidiary [1]	(228,288)	(92,700)	(231,978)	(31,611)
Other	12,837	18,169	3,153	(14)
Dividends received from subsidiaries	212,875	186,733	183,071	--
Accounts receivable	618	(891)	--	--
Income taxes	14,069	20,601	(21,951)	(1,539)
Accounts payable	--	(48)	(88,912)	--
Affiliated payables	--	--	--	20,015
Accrued interest	9,045	(926)	5,406	--
Net cash provided by (used in) operating activities	120,844	105,286	14,918	(393)
Investing activities:				
Investment in subsidiaries	(287,000)	--	(25,960)	--
(Increase) decrease in loan to subsidiaries	(7,400)	300	2,828	346
Net cash provided by (used in) investing activities	(294,400)	300	(23,132)	346
Financing activities:				
Dividends paid	(117,441)	(104,311)	(121,178)	--
Issuance of bond	787,000	450,000	50,211	--
Redemption of term-loan	(484,000)	(443,000)		
Issue costs	(6,016)	(8,157)	(6,428)	--
Net cash provided by (used in) by financing activities	179,543	(105,468)	(77,395)	--
Increase (decrease) in cash	5,987	118	(85,609)	(47)
Cash at beginning of year	237	119	85,728	57
Cash at end of year	$ 6,224	$ 237	$ 119	$ 10

1 *Equity earnings of subsidiary included earnings from PSE of $204.1 million and $26.1 million for the years ended December 31, 2011 and 2010, respectively, and purchase accounting adjustments recorded at Puget Energy for PSE of $24.2 million and $66.6 million for the years ended December 31, 2011 and 2010, respectively.*

See accompanying notes to the consolidated financial statements.

SCHEDULE II: VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

PUGET ENERGY (DOLLARS IN THOUSANDS)	BALANCE AT BEGINNING OF PERIOD	ADDITIONS CHARGED TO COSTS AND EXPENSES	DEDUCTIONS	BALANCE AT END OF PERIOD
YEAR ENDED DECEMBER 31, 2011				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 9,784	$ 18,449	$ 19,738	$ 8,495
YEAR ENDED DECEMBER 31, 2010				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 8,094	$ 23,875	$ 22,185	$ 9,784
SUCCESSOR				
PERIOD FROM FEBRUARY 6, 2009 TO DECEMBER 31, 2009				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ --	$ 25,378	$ 17,284	$ 8,094
PREDECESSOR				
PERIOD FROM JANUARY 1, 2009 TO FEBRUARY 5, 2009				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 6,392	$ 1,285	$ 7,677	$ --

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	BALANCE AT BEGINNING OF PERIOD	ADDITIONS CHARGED TO COSTS AND EXPENSES	DEDUCTIONS	BALANCE AT END OF PERIOD
YEAR ENDED DECEMBER 31, 2011				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 9,784	$ 18,449	$ 19,738	$ 8,495
YEAR ENDED DECEMBER 31, 2010				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 8,094	$ 23,875	$ 22,185	$ 9,784
YEAR ENDED DECEMBER 31, 2009				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 6,392	$ 20,220	$ 18,518	$ 8,094

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

PUGET ENERGY

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision and with the participation of Puget Energy’s management, including the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer, Puget Energy has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of December 31, 2011, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer of Puget Energy concluded that these disclosure controls and procedures are effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in Puget Energy's internal control over financial reporting during the quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, Puget Energy's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Puget Energy's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Under the supervision and with the participation of Puget Energy's President and Chief Executive Officer and Senior Vice President and Chief Financial Officer, Puget Energy's management assessed the effectiveness of internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, Puget Energy's management concluded that its internal control over financial reporting was effective as of December 31, 2011.

Puget Energy's effectiveness of internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

PUGET SOUND ENERGY

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision and with the participation of PSE's management, including the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer, PSE has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of December 31, 2011, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer of PSE concluded that these disclosure controls and procedures are effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in PSE's internal control over financial reporting during the quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, PSE's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

PSE's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Under the supervision and with the participation of PSE's President and Chief Executive Officer and Senior Vice President and Chief Financial Officer, Puget Sound Energy's management assessed the effectiveness of internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, PSE's management concluded that its internal control over financial reporting was effective as of December 31, 2011.

PSE's effectiveness of internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

BOARD OF DIRECTORS

As of March 1, 2012, eleven directors constitute Puget Energy's Board of Directors and twelve directors currently constitute PSE's Board of Directors, as set forth below. The directors are selected in accordance with the Amended and Restated Bylaws of each of Puget Energy and PSE, pursuant to which, the investor-owners of Puget Holdings (the indirect parent company of both Puget Energy and PSE) are entitled to select individuals to serve on the boards of Puget Energy and PSE.

William Ayer, age 57, is a director on the boards of both Puget Energy and PSE. Over the past 30 years, Mr. Ayer has served in a variety of leadership positions at Alaska Air Group, most recently as Chairman, President and Chief Executive Officer of Alaska Air Group, the parent company of Alaska Airlines and Horizon Air. As the current Chairman and Chief Executive Officer of Alaska Airlines, Mr. Ayer leads the nation's seventh-largest airline with 9,600 employees. He also oversees regional carrier Horizon Air and its 3,200 employees. Mr. Ayer is also a member of the board of directors of the Museum of Flight and Angel Flight West and serves on the University of Washington's Board of Regents and the NextGen Advisory Committee. Mr. Ayer's leadership in running a successful company recognized nationally for its award-winning customer service and operational performance, coupled with his community involvement in the western Washington region, are among the qualifications and attributes that led to the conclusion that he should serve on the Puget Energy and PSE boards. Mr. Ayer will retire as Chief Executive Officer of Alaska Air Group on May 15, 2012. He will remain Chairman of the board for a period of time.

Andrew Chapman, age 56, has been a director on the boards of both Puget Energy and PSE since February 2009. Mr. Chapman is currently a director on the Board of Duquesne Light Holdings, Inc. and Duquesne Light Company, which position he has held since February 1, 2010. Mr. Chapman is currently a Managing Director in the Macquarie Capital Funds division of the Macquarie Group, which position he has held since 2006. Prior to joining the Macquarie Group, Mr. Chapman was Vice President – Strategy & Regulation for American Water from 2005 to 2006 and Regional Managing Director from 2003 to 2004. Mr. Chapman represents the Company's Macquarie affiliated investors on the boards, in accordance with the terms of the Puget Energy and PSE bylaws, and brings to his service many years of experience in the operational and financial management challenges specific to regulated utilities.

Melanie Dressel, age 59, is a director on the boards of both Puget Energy and PSE, which positions she has held since December 19, 2011. Ms. Dressel is currently President and Chief Executive Officer of Columbia Bank and its parent company, Columbia Banking System, Inc., of Tacoma, Washington, which positions she has held since 2000 and 2003, respectively. An independent director not affiliated with any of the Company's investors, Ms. Dressel's leadership skills, financial experience and many ties to civic and community groups in the Company's service territory are among the reasons for her appointment to the Puget Energy and PSE boards.

Kimberly Harris, age 47, is a director on the boards of both Puget Energy and PSE, which positions she has held since March 1, 2011. Ms. Harris has also been President and Chief Executive Officer since March 1, 2011. Prior to that time, Ms. Harris served as President from July 2010 through February 2011. Ms. Harris also served as Executive Vice President and Chief Resource Officer from May 2007 until July 2010, and was Senior Vice President Regulatory Policy and Energy Efficiency from 2005 until May 2007.

Benjamin Hawkins, age 37, has been a director on the boards of both Puget Energy and PSE since May 21, 2010. Mr. Hawkins is currently a Senior Principal of Infrastructure & Timber Investments for Alberta Investment Management Corporation (AimCo), which position he has held since June 2011. Mr. Hawkins also served as Principal of Infrastructure Investments of AimCo from November 2008 until June 2011, and Portfolio Manager of Infrastructure Investments from May of 2007 until November 2008. Prior to joining AimCo, Mr. Hawkins held various positions with EPCOR Utilities, a Canadian power and water utility company. Mr. Hawkins serves on the boards as a representative of AimCo's ownership interest in the Company, pursuant to the terms of the Puget Energy and PSE bylaws, and brings to this service his skills in financial oversight of utilities.

Alan James, age 58, has been a director on the boards of both Puget Energy and PSE since February 2009, as a representative of the Company's Macquarie affiliated investors consistent with the Puget Energy and PSE bylaws. Mr. James is currently the Chairman and Senior Managing Director of Macquarie Capital (USA) Inc. based in New York where he specializes in providing M&A advice and capital raising solutions to the utility, power and renewable sectors in North America, which position he has held since 2005. Prior to that time, Mr. James was Managing Director and Head, Investment Banking Australia and New Zealand at Citigroup from 2002 to 2005 and held various positions with Deutsche Bank AG in Australia and Europe from 1993 to 2002 specializing in the energy sector. Mr. James represents the Company's Macquarie affiliated investors in accordance with the Puget Energy and PSE bylaws. Mr. James provides the boards the benefit of his broad experience with the financial needs and operational and regulatory challenges of infrastructure providers.

Alan Kadic, age 40, has been a director on the boards of both Puget Energy and PSE since February 2009. Mr. Kadic is currently a Senior Principal in the Infrastructure Group of the Private Investments department at the Canada Pension Plan Investment Board (CPPIB), which position he has held since 2007. Prior to joining CPPIB, Mr. Kadic served as Vice President at Macquarie Bank Limited in Toronto, Canada from 2001 to 2007. Mr. Kadic is currently an alternate director on the board of Wales and West Utilities, a United Kingdom natural gas distribution company, as well as MGN Gas Networks, the holding company for Wales and West Utilities. Mr. Kadic represents the ownership stake in the Company of the CPPIB, in accordance with the terms of the Puget Energy and PSE bylaws, and brings to such service his expertise in the financial and budgetary management of utility providers.

Christopher Leslie, age 47, has been a director on the boards of both Puget Energy and PSE since February 2009, as a representative of the Company's Macquarie affiliated investors consistent with the Puget Energy and PSE bylaws. Mr. Leslie is currently an Executive Director of Macquarie Group Limited, which position he has held since 2005, President of Macquarie Infrastructure and Real Assets Inc., and since 2006 Chief Executive Officer of Macquarie Infrastructure Partners Inc. Mr. Leslie served as a director on the boards of Duquesne Light Holdings, Inc. and Duquesne Light Company in 2009 and 2010. In addition to his management and banking skills, Mr. Leslie provides the Puget Energy and PSE boards the benefit of his experience with electric utilities, gas distribution systems and other aspects of the infrastructure sector.

Mary McWilliams, age 63, has been a director on the boards of both Puget Energy and PSE since March 1, 2011. Ms. McWilliams is currently the Executive Director at Puget Sound Health Alliance, which position she has held since 2008. She also served as President and Chief Executive Officer at Regence BlueShield from 2000 to 2008. In addition, Ms. McWilliams serves as Chairman of the board of the Seattle Branch of the Federal Reserve Bank of San Francisco. Ms. McWilliams's significant experience managing consumer-focused organizations with challenging regulatory and compliance regimes, as well as her extensive knowledge of the western Washington economy generally, are some of the reasons that led to her appointment to the Puget Energy and PSE boards on behalf of the CPPIB.

Herbert Simon, age 68, is a director on the board of PSE, on which he has served since March 2006. Mr. Simon has been a member of Simon Johnson, L.L.C. (real estate and venture capital projects investment company located in Tacoma, Washington) and its predecessor company since 1985. In addition, Mr. Simon serves as a Regent at the University of Washington and as a Board member of Acre, the real estate committee for the University of Washington. Mr. Simon previously served on the Advisory Boards of the University of Washington at Tacoma and its Institute of Technology. An independent director not affiliated with any of the Company's investors, Mr. Simon's long-standing involvement with the commercial, educational, political and philanthropic leadership of western Washington are among the qualifications supporting his appointment to the PSE board.

Christopher Trumpy, age 57, has been a director on the boards of both Puget Energy and PSE since January 12, 2010. Mr. Trumpy is currently the Chairman of the Pacific Carbon Trust, which position he has held since 2008. He also served as Chairman of the British Columbia Investment Management Corporation (or bcIMC) from 2000 to 2008. In addition, Mr. Trumpy served as Deputy Minister at Ministries of Finance, Environment and Provincial Revenue from 1998 to 2009. Mr.

Trumpy represents the ownership stake in the Company of bcIMC, in accordance with the terms of the Puget Energy and PSE bylaws, and provides the boards the benefit of his significant leadership roles in government and policy-making, among other attributes.

Mark Wiseman, age 41, has served as a director on the boards of both Puget Energy and PSE since October 2009. Mr. Wiseman is currently Executive Vice President Investments at the CPPIB, which position he has held since April 2010. He served as Senior Vice President Private Investments of CPPIB from 2005 to April 2010. Mr. Wiseman represents the ownership interest of the CPPIB in the Company, consistent with the Puget Energy and PSE bylaws. Among his qualifications are his experience with the capital needs of infrastructure providers as well as risk management and financial oversight.

EXECUTIVE OFFICERS

The information required by this item with respect to Puget Energy and PSE is incorporated herein by reference to the material under "Executive Officers of the Registrants" in Part I of this report.

AUDIT COMMITTEE

The Puget Energy and PSE Boards of Directors have both established an Audit Committee. Directors Andrew Chapman, Benjamin Hawkins, Alan Kadic and William S. Ayer are the members of the Audit Committee. The Board has determined that Andrew Chapman meets the definition of "Audit Committee Financial Expert" under SEC rules. Puget Energy and PSE currently do not have any outstanding stock listed on a national securities exchange and, therefore, there are no independence standards applicable to either company in connection with the independence of its Audit Committee members.

CHANGES TO THE PROCEDURES BY WHICH SHAREHOLDERS MAY RECOMMEND NOMINEES TO THE BOARD OF DIRECTORS

Following the closing of the merger, members of the Boards of Directors of Puget Energy and PSE are nominated and elected in accordance with the provisions of their respective Amended and Restated Bylaws.

CODE OF ETHICS

Puget Energy and PSE have adopted a Corporate Ethics and Compliance Code applicable to all directors, officers and employees and a Code of Ethics applicable to the Chief Executive Officer and senior financial officers, which are available on the website www.pugetenergy.com. If any material provisions of the Corporate Ethics and Compliance Code or the Code of Ethics are waived for the Chief Executive Officer or senior financial officers, or if any substantive changes are made to either code as they relate to any director or executive officer, we will disclose that fact on our website within four business days. In addition, any other material amendments of these codes will be disclosed.

ADDITIONAL INFORMATION

The Company's reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available or may be accessed free of charge at the Company's website, www.pugetenergy.com. Information may also be obtained via the SEC Internet website at www.sec.gov.

COMMUNICATIONS WITH THE BOARD

Interested parties may communicate with an individual director or the Board of Directors as a group via U.S. Postal mail directed to: Chairman of the Board of Directors, c/o Corporate Secretary, Puget Energy, Inc., P.O. Box 97034, PSE-12, Bellevue, Washington 98009-9734. Please clearly specify in each communication the applicable addressee or addressees you wish to contact. All such communications will be forwarded to the intended director or Board as a whole, as applicable.

ITEM 11. EXECUTIVE COMPENSATION

PUGET ENERGY
PUGET SOUND ENERGY
EXECUTIVE COMPENSATION

COMPENSATION AND LEADERSHIP DEVELOPMENT COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The members of the Compensation and Leadership Development Committees (referred to as the Committee) of the Boards of Directors (referred to as the Board) of Puget Energy and PSE (referred to as the Company) are named in the Compensation and Leadership Development Committee Report. No members of the Committee were officers or employees of the Company or any of its subsidiaries during 2011, were formerly Company officers or had any relationship otherwise requiring disclosure. Each member meets the independence requirements of the SEC and the NYSE.

COMPENSATION DISCUSSION AND ANALYSIS

This section provides information about the compensation program for the Company's Named Executive Officers who are included in the Summary Compensation Table. For 2011, the Company's Named Executive Officers and titles as of 2011 year end were:

- Kimberly J. Harris, President and Chief Executive Officer (CEO);
- Daniel A. Doyle, Senior Vice President and Chief Financial Officer (CFO);
- Eric M. Markell, Senior Vice President and Chief Strategy Officer and Former Chief Financial Officer (Former CFO);
- Susan McLain, Senior Vice President, Delivery Operations;
- Paul M. Wiegand, Senior Vice President, Energy Operations;
- Marla D. Mellies, Senior Vice President, Chief Administrative Officer;
- Donald E. Gaines, Vice President Finance and Treasurer (Former Principal Financial Officer);
- Stephen P. Reynolds, Former Chief Executive Officer (Former CEO); and
- Bertrand A. Valdman, Former Senior Vice President and Former Chief Financial Officer (Former CFO).

During 2011, the following changes occurred among our Named Executive Officers. Effective March 1, 2011, Mr. Reynolds retired as CEO of the Company and Ms. Harris succeeded him as CEO. On February 2, 2011, Mr. Valdman was appointed Chief Financial Officer of the Company, succeeding Mr. Markell to that position. Effective March 11, 2011, Mr. Valdman voluntarily resigned as CFO and Mr. Gaines served as acting Principal Financial Officer until Mr. Doyle's appointment as Senior Vice President and CFO of the Company in November 2011.

This section also includes a discussion and analysis of the overall objectives of our compensation program and each element of compensation the Company provides.

COMPENSATION PROGRAM OBJECTIVES

The Company's executive compensation program has two main objectives:

- Support sustained Company performance by attracting, retaining and motivating talented people to run the business.
- Align compensation payment levels with achievement of Company goals.

The Committee is responsible for developing and monitoring an executive compensation program and philosophy that achieves the foregoing objectives. In performing its duties, the Committee obtains information and advice on various aspects of executive compensation from its outside compensation consultant, Towers Watson. The Committee recommends the salary level for our CEO, based on recommendations from Towers Watson, and recommends the salary levels for the other executives, based on recommendations from our CEO, to the full Board for approval. The Committee also recommends to the Board for its approval annual and long-term incentive compensation plans for the executives, the setting of performance goals and the determination of awards under those plans.

In 2011, the Committee used the following strategies to achieve the objectives of our executive compensation program:

- *Design and deliver a competitive total pay opportunity.* To attract, retain and motivate a talented executive team, the Committee believes that total pay opportunity should be competitive with similar companies so that new executives will want to join the Company and current executives will be retained. As described below in the discussion of Compensation Program Elements (Review of Pay Element Competitiveness), the Committee annually compares executive compensation to external market data from similar companies in our industry and targets base salary and total direct compensation (which is base salary plus annual and long-term incentive pay) to the 50th percentile of this comparator group. The Committee also recognizes the importance of providing retirement income. Executives choose to work for the Company as opposed to a variety of other alternative organizations, and one financial goal of employees is to provide a secure future for themselves and their families. The Committee reviews the design of retirement programs provided by our comparator group and provides benefits that are commensurate with this group.

- *Place a significant portion of each executive's total compensation at risk to align executive compensation with Company financial and operating performance.* Under its "pay for performance" philosophy, the Committee works to design and deliver an incentive compensation program that supports the Company's business direction as approved by the Board and aligns executive interests with those of investors and customers. The Committee believes that a significant portion of each executive's compensation should be "at risk" and rewarded solely for meeting and exceeding target levels of annual and long-term performance goals. By establishing goals, monitoring results, and rewarding achievement of goals, the Company focuses executives on actions that will improve the Company and enhance investor value, while also retaining key talent. The Committee annually evaluates the performance factors and targets for our annual and long-term incentive programs and considers adjustments as appropriate to meet the objectives of our executive compensation program. As described below, the Company's policies and practices surrounding incentive pay are structured in a manner to mitigate the risk that employees would seek to take untoward risks in an attempt to increase incentive results.

- *Execute the Company's succession planning process to ensure that executive leadership continues uninterrupted by executive retirements or other personnel changes.* The CEO leads the talent reviews for leadership succession planning through meetings with her executive team. Each executive conducts talent reviews of senior employees that report to him or her and whom have high potential for assuming greater responsibility in the Company. The talent reviews include evaluations prepared within the Company and by external organizational development consultants. The Committee and the Board annually review these assessments of executive readiness, the plans for development of the Company's key executives, and progress made on these succession plans. The Committee and the Board directly participate in discussion of succession plans for the position of CEO.

RISK ASSESSMENT

A portion of each executive's total direct compensation is variable, at risk and tied to the Company's financial and operational performance to motivate and reward executives for achievement of Company goals. The Company's variable pay program helps focus executives on interests important to the Company and its investors and customers and creates a record of their results. In structuring its incentive programs, the Company also strives to balance and moderate risk to the Company from such programs: individual award opportunities are defined and subject to limits, goal funding is based on collective company performance, annual incentive awards are balanced by long-term incentive awards that measure performance over three years, performance targets are based on management's operating plan (which includes providing good customer service), and all incentive awards to individual executives are subject to discretionary review by management, the Committee and/or the Board. As a result, the Committee and the Board believe that the programs' design do not provide an incentive to executives to take unreasonable risks that could have a material adverse effect relating to the Company's business and also provide appropriate incentive opportunities for executives to achieve Company goals that support the interests of our investors and customers.

COMPENSATION PROGRAM ELEMENTS

The Company's compensation program encompasses a mix of base salary, annual and long-term incentive compensation, retirement programs, health and welfare benefits and a limited number of perquisites. The Company also provides certain post-termination and change in control benefits to executives who were employed by the Company prior to March 2009. Since the Company is no longer publicly listed following its merger in February 2009 and no longer grants equity awards to its executives, it relies on a mix of non-equity compensation elements to achieve its compensation objectives.

The total compensation package is designed to provide participants with appropriate incentives that are competitive with the comparator group and is also designed to achieve current operational performance and customer service goals as well as the long-term objective of enhancing investor value. The Company does not have a specific policy regarding the mix of compensation elements, though long-term incentive programs are designed to comprise the largest portion of each executive's incentive pay. The Company arrives at a mix of pay by setting each compensation element relative to market comparators. The Company delivered cash compensation to the Named Executive Officers in 2011 through base salary to provide liquidity for the executives and through incentive programs to focus performance on important Company goals and to increase the alignment with investors. The Committee annually reviews total compensation opportunity and actual total compensation received over the prior years by each executive officer in the form of a tally sheet. This review helps inform the Committee's decisions on program designs by allowing the Committee to review overall pay received in relation to Company results.

Review of Pay Element Competitiveness

In making compensation decisions on base salary and annual and long-term incentive programs, management prepares comprehensive pay surveys for review by the Committee and the Committee's outside executive pay consultant, Towers Watson. The Committee also received advice from Towers Watson in making 2011 compensation decisions. The surveys summarize data provided by the Towers Watson 2010 Energy Services survey for a selection of utility and other companies that are most similar in scope and size to PSE. For the review of compensation pay levels and practices in 2011, we included the following utility companies in our comparator group that were all of similar scope (generally $1.5 billion — $6.0 billion revenue and $4.0 billion — $12.0 billion asset size) and also participated in the Towers Watson 2010 Energy Services survey:

1. Allegheny Energy
2. Alliant Energy
3. Atmos Energy
4. Avista
5. CMS Energy
6. MDU Resources
7. New York Power Authority
8. Nicor
9. Northeast Utilities
10. NSTAR/MA
11. NV Energy
12. OGE Energy
13. Pinnacle West Capital
14. PNM Resources
15. Portland General Electric
16. SCANA
17. Southern Union Company
18. Westar Energy
19. Wisconsin Energy

Base pay and total direct compensation (which is base salary plus annual and long-term incentive pay) are targeted to the 50th percentile of the industry comparator group if the Company's performance goals are achieved at target. If results are below expectations, total direct compensation is lower than this targeted level. If achievement of performance goals significantly exceeds target, total cash compensation can approach the 75th percentile of the industry comparator group.

Individual pay adjustments are reviewed to see how they position the executive in relation to the median of market pay, while also considering the executive's recent performance and experience level. The Company may choose to pay an executive above or below the median level of market pay when that individual has a role with greater or lesser responsibility than the best comparison job or when our executive's experience and performance exceed those typically found in the market.

Base Salary

We recognize that it is necessary to provide executives with a fixed amount of total compensation that is delivered each month and provides a balance to other pay elements that are at risk. Base salaries are generally targeted at the 50th percentile of the comparator group and are reviewed annually by the Committee on an individual basis using as a guideline, median salary levels of our comparator group, as well as internal pay equity among executives. Actual salaries vary by individual and depend on additional factors, such as an individual's expertise, level of performance achievement, level of experience and level of contribution relative to others in the organization.

Base Salary Adjustments

The Committee reviewed the base salaries of the Named Executive Officers in early 2011 and, for the first time since 2009, recommended base salary adjustments to the Board. Previously executive base salaries had not changed since 2009 in light of the continued difficult economic environment faced by the Company and many of our customers. The Board approved the Committee's recommendation to increase executive salaries, and base salaries for 2011 generally remained at the median of market among the comparator group. The salary increase percentages approved by the Board were in a range of 2% to 5%, similar to salary increases processed for other non-represented employees.

Effective March 1, 2011, the Board appointed Ms. Harris CEO of the Company and increased her base salary from $680,000 to $720,000. In establishing the level of pay for Ms. Harris, the Committee recommended and the Board approved a base salary that was below the median of market among the comparator group, reflecting Ms. Harris's new tenure in 2011 as both President and CEO. Effective November 18, 2011, the Board appointed Mr. Doyle as Senior Vice President and CFO of the Company. Mr. Doyle's base salary was set at $450,000, slightly below the median of market among the comparator group. Ms. Mellies was promoted to Senior Vice President and Chief Administrative Officer on February 1, 2011 and received a salary increase to $265,000, which placed her slightly below the median of market among the comparator group.

Incentive Compensation (Annual and Long-Term)

Our annual and long-term incentive plans help focus executives on the priorities of our investors and customers and reward performance that meets or exceeds pre-established goals. Both the Company's annual incentive plan and the long-term incentive plan measure and reward the Company's performance on Service Quality Indices (SQIs). These reporting measures were developed in collaboration with the Company's regulator, the Washington Commission, and provide customers with a report card on the Company's customer service and reliability. In addition to SQI achievement, performance measures used in 2011 for determining incentives were EBITDA in the annual incentive plan and Total Return in the long-term incentive plan. EBITDA and Total Return are important performance measures of economic return to our investors, and their accomplishment indicates to our customers that the Company has the financial strength needed for long-term sustainability.

Based on the recommendations of management and the Committee, the Board approved certain changes to the annual and long-term incentive programs which will take effect in 2012. Although these changes do not apply to our incentive compensation plans as in effect during 2011, they are described briefly below because they were approved in 2011.

2011 Annual Incentive Compensation

All PSE employees, including executive officers, are eligible to participate in an annual incentive program referred to as the "Goals and Incentive Plan." The plan is designed to provide financial incentives to executives for achieving desired annual operating results, measured by EBITDA, while also meeting the Company's service quality commitment to customers. EBITDA was selected as a performance goal because it provides a financial measure of cash flows generated from the Company's annual operating performance.

For 2011, the Company's service quality commitment was measured by performance against 9 SQIs covering three broad categories, set forth below. These are the same SQIs for which the Company is accountable to the Washington Commission. The Company's annual report to the Washington Commission and our customers describes each SQI, how it is measured, the Company's required level of achievement, and performance results. For 2011, the Washington Commission agreed to continued removal of one SQI that had been applicable for prior years relating to limiting disconnects for non-payment; during the Company's current general rate case, the Washington Commission will determine if that measure should be reinstated for future years.

The Company's service quality report cards are available at http://www.PSE.com/PerformanceReportCards.

The SQIs for 2011 were as follows:

- **Customer Satisfaction (3 SQIs)**
  - — Customer satisfaction with the telephone access center and gas field services and number of Washington Commission complaints
- **Customer Service (2 SQIs)**
  - — Calls answered "live" and on-time appointments
- **Safety and Reliability (4 SQIs)**
  - — Gas emergency response, electric emergency response, non-storm outage frequency and non-storm outage duration

The annual incentive plan for 2011 had a funding level based on customer service, as measured by SQI achievement, and EBITDA as shown in the table below.

ANNUAL INCENTIVE PERFORMANCE PAYOUT SCALE

PERFORMANCE	2011 EBITDA (IN MILLIONS)	SQI*	FUNDING LEVEL
Maximum	$1,324.35	9/9	200%
Target	981.0	9/9	100%
Threshold Payout Funding	882.9	6/9	35%

* SQI results of 6/9 or better and minimum EBITDA of $882.9 million are required for any incentive payout funding. SQI results below 9/9 reduce funding (e.g., 8/9 = 90%, 7/9 = 80%, 6/9 = 70%).

2011 Actual Performance	$ 1,022.5	9/9	121.2%

The Committee can adjust EBITDA used in the annual incentive calculation to exclude nonrecurring items that are outside the normal course of business for the year, but did not exclude any items for 2011. Individual awards may be adjusted upward or downward based on a subjective evaluation of an executive officer's performance against individual and team goals. Individual goals were developed from the overall corporate goals for 2011, set forth below:

2011 Corporate Goals

- **Enhance Customer Service** — Respond to our customers by listening, leveraging new systems, updating processes and providing innovative and improved services, products and programs.
- **Optimize Generation and Delivery** — Secure and maintain reliable resources, build or replace infrastructure in a way that meets our customers' needs, promotes environmental stewardship and provides a fair return to investors.
- **Be a Good Neighbor** — Embrace our role as a leader to protect and improve our natural gas and electric service, promote energy efficiency initiatives, encourage corporate giving and instill community involvement.
- **Value Employees** — Safety is key; work safely. Value diversity, teamwork and open communication. Support employees through technology, process improvement, recognition, training and development. Strive to make PSE a great place to work.
- **Own it —** Conduct ourselves and our business in a manner that is ethical, responsible and meets or exceeds any internal or external compliance obligation. Take personal responsibility for meeting customer needs while using company resources and facilities wisely.
- **Continue to Learn and Grow —** Strive to get better at what we do every day. Continuously examine past practices, challenge our assumptions and apply lessons learned to improve our efforts on behalf of customers and the community.

Achievement of the corporate goals for 2011 was above target for EBITDA, and at target for SQI achievement. PSE EBITDA was $1,022.5 million, and SQI achievement was 9 out of 9, leading to a funding level for 2011 of 121.2%.

For 2011, individual target incentive levels for this plan varied by executive officer as a percentage of base salary as shown in the table below, based on the individual executive's level of responsibility within the Company. With the exception of Ms. Mellies, who received a promotion during 2011, target annual incentive opportunities for participating executives remained unchanged from 2010 levels. The maximum incentive for exceptional performance in this plan is twice the target incentive. As described above, an executive's individual award amount can be increased or decreased based on a subjective assessment by the CEO (or the Board in the case of the CEO) of the executive's individual and team performance results. After considering performance on individual and team goals, which were determined to be met by each executive, the CEO did not recommend any adjustment to award amounts for the Named Executive Officers (below the CEO) in 2011, except to recommend an increase in award amount for Mr. Gaines' individual performance in 2011, taking into consideration he served as acting Principal Financial Officer for much of the year. The Board approved the amounts shown below, which were paid in March 2012. Mr. Reynolds retired with two months of service in 2011 and was not eligible for an annual incentive award. Mr. Valdman voluntarily terminated employment during 2011 and as a result forfeited eligibility for payment of a 2011 annual incentive award.

NAME	TARGET INCENTIVE (% OF BASE SALARY)	2011 ACTUAL INCENTIVE PAID	2011 ACTUAL INCENTIVE (% OF BASE SALARY)
Kimberly J. Harris	85%	$ 741,744	103%
Daniel A. Doyle*	Not eligible	0	0%
Eric M. Markell	60%	242,158	65%
Susan McLain	45%	160,348	55%
Paul M. Wiegand	45%	147,258	55%
Marla D. Mellies	45%	144,531	55%
Donald E. Gaines	40%	117,855	53%
Stephen P. Reynolds**	Not eligible	0	0%
Bertrand A. Valdman**	60%	0	0%

* *Mr. Doyle joined PSE in November 2011 and was not eligible for a 2011 annual incentive. Mr. Doyle has a target incentive of 45% of base salary in 2012.*

** *As described above, Mr. Reynolds was not eligible for a 2011 annual incentive and Mr. Valdman forfeited eligibility for payment of a 2011 annual incentive.*

In addition to the annual incentive program, the Named Executive Officers, other than Mr. Reynolds and Mr. Doyle, were eligible to receive merger performance bonuses in 2011 under the terms of their Executive Employment Agreements. (See the section Post-Termination Benefits below.)

Annual Incentive Plan for 2012

During 2011, Company management recommended and the Board approved one change to the annual incentive plan to be effective with the 2012 performance year. To emphasize the Company's continued commitment to employee safety, the Company added a new safety performance measure to the annual incentive plan funding for 2012. The employee safety measure will function like the 9 SQIs in determining the funding of the incentive plan. In 2012 the annual incentive funding table will require achievement of all 9 SQIs and achievement of the safety measure for 100% funding of the plan at target EBITDA performance. If the safety measure is missed, annual incentive funding will be decreased by 10%, in the same way as a missed SQI. The safety performance measure contains five targets which must all be satisfied for the safety measure to be met. If the safety measure is not achieved, annual incentive funding will be decreased in the same manner as if an SQI measure is not achieved. The five targets are:

- Frontline supervisors receive appropriate safety and health training.
- New employees receive applicable safety and health orientation.
- Actively reduce the risk of ergonomic office injuries.
- Reduce the Company Total Incident Case Rate (TICR) by 4% of the year end 2011 TICR.
- Reduce the Company Lost Workday Case Rate (LWCR) by 15% of the year end 2011 LWCR.

Long-Term Incentive Compensation

Long-term incentive compensation opportunities are designed to be competitive with market practices, reward long-term performance and promote retention. Prior to completion of our merger in February 2009, executives received equity awards under the Puget Energy 2005 LTI Plan in the form of performance shares and performance-based restricted stock. Awards generally vested based on the Company achieving a targeted level of performance during a three-year performance cycle.

Upon the merger, all unvested LTI Plan awards accelerated in vesting and became payable in cash in 2009 pursuant to the terms of the LTI Plan. Following our merger, the Company has continued the basic design of the pre-merger LTI Plan, including retention of three-year performance cycles that begin each year. Since the Company no longer has publicly listed stock and no longer grants equity awards to its employees, LTI Plan awards are now denominated in units and are settled in cash if threshold performance measures are met. The Board approved a change in performance measures for the 2012-2014 performance cycle, which is described below. The remainder of this section discusses currently outstanding LTI Plan grants under the 2009-2011, 2010-2012 and 2011-2013 performance cycles. The LTI Plan grants for the 2009-2011 performance cycle vested at the end of 2011 and will be paid in cash in March 2012 based on achieved performance as described below.

The Committee determines the number of LTI Plan units granted to each executive by evaluating the actual payment and forecast target payment of long-term incentive awards of our market comparator group for comparable levels of responsibility. The Committee generally does not consider previously granted awards or the level of accrued value from prior or other programs when granting annual incentive awards or making new LTI Plan grants. Each year's grant is primarily viewed in the context of the compensation opportunity needed to maintain the Company's competitive position relative to the comparator group.

Target LTI Plan awards are calculated based on a percentage of an executive's annual base salary, taking into account the executive's level of responsibility within the Company. Target LTI Plan awards for the 2011-2013 performance cycle were 170% of base salary for Ms. Harris; 110% for Mr. Valdman and Mr. Markell; 95% for Ms. McLain, Mr. Wiegand and Ms. Mellies; and 50% for Mr. Gaines. Mr. Reynolds was not granted a 2011-2013 LTI Plan grant because he retired effective March 1, 2011. Mr. Valdman's 2011-2013 LTI Plan grant was forfeited when he voluntarily terminated employment on March 11, 2011. In connection with his hire on November 28, 2011, Mr. Doyle received a pro-rata grant of 2011-2013 LTI Plan units based on a target of 95% of base salary. Details of the number of units granted and expected value can be found in the "2011 Grants of Plan-Based Awards" table below. With the exception of Ms. Mellies, who was promoted during 2011, target LTI Plan award opportunities as a percentage of base salary remained unchanged from 2010 levels for the continuing Named Executive Officers.

Except for the CEO, 50% of each grant of LTI Plan units is allocated to achievement of SQIs only (SQI component) and 50% is allocated to achievement of a combination of SQIs and Total Return (Total Return component). The CEO's LTI Plan units are allocated 30% to the SQI component and 70% to the Total Return component to place additional weight on financial measures, consistent with our comparator group companies. The total number of LTI Plan units granted to a Named Executive Officer is equal to the applicable percentage of salary (converted to dollars) divided by the per unit value at the beginning of the performance cycle. For the 2011-2013 performance cycle, the initial per unit value was $33.80.

The total amount payable for a performance cycle is calculated at the end of the performance cycle based on the actual level of achievement of SQIs and Total Return as well as the per unit dollar value at the end of the performance cycle. Unit value is measured at the Puget Holdings LLC level and is re-calculated each year based on the change in Total Return for the prior year as measured by an independent auditing firm. Total Return reflects the annual change in the value of the Company plus any distributions made to investors. For any award to be earned in a performance cycle, average SQI results must meet or exceed 80% accomplishment of the applicable SQIs, which for the 2011-2013 performance cycle are the same SQIs set forth above under "2011 Annual Incentive Compensation." Executives generally must be employed on the payment date to receive a cash payment under the LTI Plan, except in the event of retirement at normal retirement age or approved early retirement, disability or death.

The tables and points below summarize the performance measures and design of the LTI Plan grants for the current performance cycles.

Grant Cycle	SQI Component	Total Return Component**
2011-2013*	50%	50%
2010-2012*	50%	50%
2009-2011*	50%	50%

* *CEO grants are split 30% SQI Component and 70% Total Return Component.*

** *Total Return Component is determined based on a combination of Total Return and 3-year average SQI results.*

The table below shows the percentage of LTI Plan target awards that will be earned based on three-year average SQI achievement.

SERVICE QUALITY INDICES (SQIS) COMPONENT TABLE

SQI RESULT, 3 YEAR AVERAGE	PERCENTAGE OF LTI PLAN TARGET AWARD
80% achievement or above *	100%
Below 80%	0%

* *For 2009 in the 2009-2011 performance cycle, SQIs results were measured against 10 SQIs. 9 SQIs applied for the remaining years in the 2009-2011 performance cycle and 9 SQIs currently apply to the 2011-2013 and 2010-2012 performance cycles.*

The table below shows the percentage of LTI Plan target awards under the Total Return Component that will be earned based on three-year performance. Percentages will be interpolated if performance falls between the values shown below.

TOTAL RETURN COMPONENT TABLE

	PERCENTAGE OF LTI PLAN TARGET AWARD			
ANNUALIZED 3 YEAR RETURN	100% SQI (3 YEAR AVERAGE)	90% SQI (3 YEAR AVERAGE)	80% SQI (3 YEAR AVERAGE)	<80% SQI (3 YEAR AVERAGE)
15% or more	210%	175%	155%	0%
14%	180%	150%	130%	0%
13%	150%	125%	105%	0%
12%	120%	100%	80%	0%
11%	80%	65%	50%	0%
10%	40%	30%	20%	0%
<10%	0%	0%	0%	0%

SQI Component (50%):

- A target number of units are granted under this component at the beginning of a three-year performance cycle that will be paid in cash to the participant if the Company achieves the targeted level of 80% of SQIs during the performance cycle. The actual award is paid at target level if an average of at least 80% of SQIs are satisfied during the performance cycle, but is not paid if the average is below 80%. If targeted SQI performance is met, the amount payable is equal to the product of the target number of units granted under this component and the per unit value at the end of the performance cycle.
- If 80% of SQIs are met during the performance cycle, but the Total Return threshold of 10% is not met, the SQI component will still be paid at target.

Total Return Component (50%):

- A target number of units are granted under this component at the beginning of a three-year performance cycle that will be paid in cash to the participant if the Company achieves the targeted level of Total Return and SQI performance during the three-year performance cycle. The actual award paid is based on Company performance relative to target, subject to a minimum threshold level of performance of 10% for Total Return (based on average Total Return over the performance cycle) and average SQI achievement of 80%.
- The LTI Plan unit value is determined annually by applying the Total Return for each year to the prior year's unit price.
- At the completion of the performance cycle, if the Total Return component is paid, the participant receives a cash payment equal to the number of units earned under this component based on performance during the performance cycle multiplied by the unit price at the end of the performance cycle.
- If the Total Return component exceeds 10% annualized 3-year return, but the SQI threshold is not met, the Total Return component will not be paid.

LTI Plan Performance of Outstanding Awards

2011-2013 Performance Cycle:

- Award calculation is based on the full three-year performance cycle, so no award payment calculations will be made until after 2013.
- Performance on the SQI component for 2011 was at 9 out of 9, which if continued for the remaining two years of the performance cycle would mean that the SQI component would pay based on the target number of units granted to a Named Executive Officer.
- Performance on the Total Return component during 2011 was 6.6%, below the three-year average threshold needed for payment.

2010-2012 Performance Cycle:

- Award calculation is based on the full three-year performance cycle, so no award payment calculations will be made until after 2012.
- Performance on the SQI component of the grant was at 9 out of 9 in both 2010 and 2011, which if continued for the remaining year of the performance cycle would mean that the SQI component would pay based on the target number of units granted to a Named Executive Officer.
- Performance on the Total Return component during 2010 was 7.1% and during 2011 was 6.6%, for a combined two-year average of 6.8%, below the three-year average threshold needed for payment.

Following his retirement, Mr. Reynolds received a pro-rated payment of $150,204 for 2010 under the 2010-2012 performance cycle, based on actual performance for 2010 under the performance cycle and a per unit price of $33.80, as determined as of the end of 2010.

2009-2011 Performance Cycle:

The 2009-2011 performance cycle has now ended and had the performance described below. Amounts payable as a result of award vesting are shown in the table below.

- Performance on the SQI component of the grant was at 9 out of 10 in 2009, or 90%, and 9 out of 9 in 2010 and 2011, or 100%, for a combined two-year result of 97.5%, which qualified for payment of the SQI component based on the target number of units granted to a Named Executive Officer.
- Performance on the Total Return component during 2009 was 5.2%, during 2010 was 7.1% and during 2011 was 6.6%, for a combined three-year average result of 6.3%, below the three-year average threshold needed for payment.

Name	Target Incentive (% of Base Salary) [1]	Total Return Component Units Granted/Paid	SQI Component Units Granted/Paid	2009-2011 Actual LTIP Paid [2]
Kimberly J. Harris	110%	6,600/0	6,600/0	$ 237,798
Daniel A. Doyle [3]	Not eligible	0	0	0
Eric M. Markell	110%	6,600/0	6,600/6,600	237,798
Susan McLain	95%	4,507/0	4,507/4,507	162,387
Paul M. Wiegand	50%	2,601/0	2,601/2,601	93,714
Marla D. Mellies	50%	2,433/0	2,433/2,433	87,661
Donald E. Gaines	50%	1,769/0	1,769/1,769	63,737
Stephen P. Reynolds [4]				0
Bertrand A. Valdman [5]	110%	7,242/0	7,242/0	0

1 *Target LTI Plan Incentive is a percentage of 2009 base salary when the grants were made in 2009. Ms. Harris, Mr. Wiegand, and Ms. Mellies had lower LTI Plan targets in 2009 compared to their 2011 targets.*

2 *2009-2011 Actual LTI Plan amount payable is unit price $(36.03) multiplied by SQI Component units. The Total Return Component Units did not meet minimum performance threshold for payment.*

3 *Mr. Doyle joined PSE in November 2011 and was not eligible for a 2009-2011 LTIP.*

4 *Mr. Reynolds received payment of his 2009-2011 LTIP grant on a pro-rata basis during March 2011 after his retirement, an amount totaling $316,030.*

5 *Mr. Valdman forfeited his 2009-2011 LTIP grant when he voluntarily terminated in March 2011.*

Long Term Incentive Plan Grants for 2012-2014

As described above, the LTI Plan structure from 2009 through 2011 maintained the basic design which had been in place prior to the Company's merger in 2009. Effective with the 2012-2014 LTI Plan grants, the Board has approved a modification to the performance measures of the LTI Plan. Under this modification, SQI achievement has been removed as a performance measure from the 2012-2014 performance cycle in favor of two financial performance measures, Total Return and Return on Equity. Other aspects of the program, such as three-year performance cycles and the target levels of grants, remain unchanged. The Board modified the performance measures and related levels of achievement percentages that trigger payouts in order to ensure that the LTI Plan continues to be viewed as an incentive by the participants and aligns the interests of participants with those of our investors.

The Total Return performance measure continues as a key measure of the LTI Plan, with the revised achievement percentage scale shown in the table below. This modified scale is intended to expand the range of performance that will trigger plan funding. The SQI factor of the Total Return component has been removed to make the plan easier to understand and to remove the duplication of rewards based on SQI performance, since SQI performance is already factored into the annual incentive plan.

A new Return on Equity (ROE) scale has been added as the second LTI Plan performance measure. It replaces the SQI performance measure and means that both LTI Plan performance measures are financial in nature. The Board felt that ROE was an appropriate measure to add, since Company management has been tracking ROE and seeking to improve Company results on this measure. The ROE performance is measured each year by comparing actual ROE to the approved financial plan's ROE for that year. The average of each year during the three-year performance cycle will determine the final ROE award. The ROE scale is shown below. With the implementation of solely financial performance measures, the President and CEO position will receive grants of LTI Plan units with a 50%/50% split between Total Return and ROE, like all other LTI Plan participants. Named Executive Officers received 2012-2014 LTI Plan grants of units in the amounts and at grant values shown in the footnote to the Summary Compensation Table – 2011 Grants of Plan Based Awards.

TOTAL RETURN COMPONENT TABLE

TOTAL RETURN, 3 YEAR AVERAGE*	PERCENTAGE OF LTI PLAN TARGET AWARD
Greater than 15%	200%
14%	180%
13%	160%
12%	140%
11%	120%
10%	100%
9%	80%
8%	60%
7%	40%
6%	20%
Less than 6%	0%

* Results between rows will be interpolated.

RETURN ON EQUITY (ROE) COMPONENT TABLE

RETURN ON EQUITY COMPARED TO TARGET*	PERCENTAGE OF LTI PLAN TARGET AWARD
Target + 250 bps or more	200%
Target + 200 bps	180%
Target + 150 bps	160%
Target + 100 bps	140%
Target + 50 bps	120%
Target	100%
Target – 50 bps	80%
Target – 100 bps	60%
Target – 150 bps	40%
Target – 200 bps	20%
Target – more than 200 bps	0%

*BPS is basis points. Results between rows will be interpolated.

Retirement Plans — SERP and Retirement Plan

The Company maintains the Supplemental Executive Retirement Plan (SERP) for executives to provide a benefit that is coordinated with the tax-qualified Retirement Plan for Employees of Puget Sound Energy, Inc. (Retirement Plan). Without the addition of the SERP, these executives would receive lower percentages of replacement income during retirement than other employees. All the Named Executive Officers except Mr. Reynolds participate in the SERP. When Mr. Reynolds was hired, he elected to receive an annual contribution to his account in the Deferred Compensation Plan for Key Employees in lieu of participating in the SERP, as described in the following paragraph. Additional information regarding the SERP and the Retirement Plan is shown in the “2011 Pension Benefits” table.

Deferred Compensation Plan

The currently serving Named Executive Officers are eligible to participate in the Deferred Compensation Plan for Key Employees (Deferred Compensation Plan). The Deferred Compensation Plan provides executives an opportunity to defer up to 100% of base salary, annual incentive bonus and LTI Plan awards, plus receive additional Company contributions made by PSE into an account that has three investment tracking fund choices. The funds mirror performance in major asset classes of bonds, stocks, and an interest crediting fund that changes rates quarterly. Prior to 2012, the interest crediting fund was based on corporate bond rates, but effective for deferrals after December 31, 2011, it will be based on a money market rate. The Deferred Compensation Plan is intended to allow the executives to defer current income, without being limited by the Internal Revenue Code contribution limitations for 401(k) plans and therefore have a deferral opportunity similar to other employees as a percentage of eligible compensation. The Company contributions are also intended to restore benefits not available to executives under PSE’s tax-qualified plans due to Internal Revenue Code limitations on compensation and benefits applicable to those plans. Under the terms of Mr. Reynolds’ employment agreement, he additionally received an annual Company contribution to his Deferred Compensation Plan account equal to 15% of the base salary and annual incentive payment he received during the prior year. Additional information regarding the Deferred Compensation Plan is shown in the "2011 Nonqualified Deferred Compensation" table.

Post-Termination Benefits

The Company has entered into employment agreements with certain of its current executive officers that provide for certain payments and benefits if an executive's employment is terminated or terminates for certain reasons, such as following a change in control. The Company entered into these agreements for two primary reasons. First, many executives when joining a new company require a level of assurance that they will receive pay in the event of a termination of employment following a change in control after they join the company. Second, the Company provided these agreements so that executives are focused on the Company's ongoing operations and are not distracted by the employment uncertainty that can arise in the event of a change in control. The Committee periodically reviews existing change in control and severance arrangements for the comparator group considering benchmarking information provided by Towers Watson. Based on this information, the Committee believes that the arrangements generally provide benefits that are similar to those of the comparator group for longer tenured executives, but is not extending them to newly hired executives.

Effective March 30, 2009, the Company entered into Executive Employment Agreements with the Named Executive Officers, except Mr. Reynolds and Mr. Doyle (who was not then employed by the Company), which amended and restated existing Amended and Restated Change of Control Agreements between the Company and each of the executives. The Executive Employment Agreements provided for an employment period of two years following the February 6, 2009 completion of the merger and generally provided benefits similar to those under the previous Change of Control Agreements. In addition, the agreements provided for a merger performance bonus equal to 100% of the executives' annual base salary, payable on or shortly following each of the first and second anniversaries of the completion of the merger if the Company achieves specified minimum SQI performance goals established by the Committee (for 2010, 80% of SQIs or better) and the executive remains employed at the Company until the anniversary of the merger for which payment is made. In February 2011, Ms. Harris, Mr. Markell, Ms. McLain, Mr. Wiegand, Ms. Mellies, Mr. Gaines, and Mr. Valdman each received merger performance bonuses in the amounts set forth in the Summary Compensation Table. Under the terms of the employment agreements, the executives are not eligible to receive additional merger performance bonuses in future years. Since the 2009 merger, the Company has ceased entering into these agreements with new executive officers.

Mr. Reynolds' employment agreement terminated effective February 28, 2011 in connection with his retirement as CEO.

The "Potential Payments Upon Termination or Change in Control" section describes the current post-termination arrangements with the Named Executive Officers as well as other plans and arrangements that would provide benefits on termination of employment or a change in control, and the estimated potential incremental payments upon a termination of employment or change in control based on an assumed termination or change in control date of December 30, 2011, the last business day of 2011.

Other Compensation

In addition to base salary and annual and long-term incentive award opportunities, the Company also provides the Named Executive Officers with benefits and perquisites targeted to competitive practices. The Company may provide payments upon hiring a new executive to help offset the executive's relocation expenses, a practice needed to attract qualified candidates from other areas of the country. In connection with the November 2011 hire of Mr. Doyle, the Company provided a payment for relocation expenses, as described in the Other Compensation Table to the Summary Compensation Table below. The terms of the payment require Mr. Doyle to pay it back if he resigns or is terminated for cause within twenty-four months of hire. The current executives participate in the same group health and welfare plans as other employees. Company vice presidents and above, including the Named Executive Officers, are eligible for additional disability and life insurance benefits. The executives are also eligible to receive reimbursement for financial planning, tax preparation, legal services, business club memberships and executive physicals up to an annual limit. The reimbursement for financial planning, tax preparation and legal services is provided to allow executives to concentrate on their business responsibilities. Business club memberships are provided to allow access for business meetings and business events at club facilities and executives are required to reimburse the Company for individual use of club facilities. These perquisites generally do not make up a significant portion of executive compensation and, other than the relocation amount paid to Mr. Doyle, do not exceed $10,000 in total for each Named Executive Officer in 2011.

Relationship among Compensation Elements

A number of compensation elements increase in absolute dollar value as a result of increases to other elements. Base salary increases translate into higher dollar value incentive opportunity for annual and long-term incentives, because each plan operates with a target level award set as a percentage of base salary. Base salary increases also increase the level of retirement benefits, as do actual annual incentive plan payments. Some key compensation elements are excluded from consideration when determining other elements of pay. Retirement benefits exclude LTI Plan payments in the calculation of qualified retirement (pension and 401(k)) and SERP benefits.

Impact of Accounting Treatment of Compensation

The accounting treatment of compensation generally has not been a factor in determining the amounts of compensation for our executive officers. However, the Company considers the accounting impact of various program designs to balance the potential cost to the Company with the benefit/value to the executive.

COMPENSATION AND LEADERSHIP DEVELOPMENT COMMITTEE REPORT

The Board delegates responsibility to the Compensation and Leadership Development Committee to establish and oversee the Company's executive compensation program. Each member of the Committee served during all of 2011.

The Committee members listed below have reviewed and discussed the "Compensation Discussion and Analysis" with the Company's management. Based on this review and discussion, the Committee recommended to the Board, and the Board has approved, that the "Compensation Discussion and Analysis" be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2011 for filing with the SEC.

Compensation and Leadership
Development Committee of
Puget Energy, Inc.
Puget Sound Energy, Inc.

Mark Wiseman, Chair
Christopher Leslie
Herbert B. Simon (PSE Only)
Christopher Trumpy

SUMMARY COMPENSATION TABLE

The following information is furnished for the year ended December 31, 2011 (and for prior years where applicable) with respect to the Named Executive Officers during 2011. The positions listed below are at Puget Energy and PSE, except that Mr. Markell, Ms. McLain, Mr. Wiegand, and Ms. Mellies are executives of PSE only. Positions listed are those held by the Named Executive Officers as of December 31, 2011. Salary and incentive compensation includes amounts deferred at the executive's election.

Name and Principal Position	Year	Salary	Bonus	Stock Awards	Option Awards	Non-Equity Incentive Plan Compensation [1]	Change in Pension Value and Nonqualified Deferred Compensation Earnings [2]	All Other Compensation [3]	Total
Kimberly J. Harris President and Chief Executive Officer(4)	2011	$ 711,833	$ --	$ --	$ --	$ 1,659,542	$ 857,618	$ 25,387	3,254,380
	2010	506,667	$ --	--	$ --	681,173	445,997	25,935	1,659,772
	2009	360,000	15,638	--	--	156,384	222,948	270,937	1,025,907
Daniel A. Doyle Senior Vice President and Chief Financial Officer (5)	2011	$ 23,864	$ --	$ --	$ --	$ --	$ 6,685	$ 160,746	$ 191,295
Eric M. Markell Senior Vice President and Chief Strategy Officer and Former Chief Financial Officer (6)	2011	$ 367,958	$ --	$ --	$ --	$ 839,956	$ 477,182	$ 45,189	$ 1,730,285
	2010	360,000	--	--	--	534,744	423,394	42,871	1,361,009
	2009	360,000	15,638	--	--	156,384	309,648	289,672	1,131,342
Susan McLain Senior Vice President, Delivery Operations (7)	2011	$ 292,086	$ --	$ --	$ --	$ 607,360	$ 289,698	$ 32,303	$ 1,221,447
Paul M. Wiegand Senior Vice President, Energy Operations (8)	2011	$267,963	$ --	$ --	$ --	$ 500,994	$ 306,711	$ 34,220	$ 1,109,888
Marla D. Mellies Senior Vice President, Chief Administrative Officer (9)	2011	$ 260,554	$ --	$ --	$ --	$475,417	$ 167,110	$ 24,588	$ 927,669
Donald E. Gaines Vice President Finance and Treasurer and Former Acting Principal Financial Officer	2011	$ 219,198	$ 10,714	$ --	$ --	$383,053	$ 195,936	$ 24,617	$ 833,518
	2010	212,175	--	--	--	280,835	156,474	22,570	672,054
Stephen P. Reynolds Former Chief Executive Officer (10)	2011	$168,438	$ --	$ --	$ --	$ 466,234	$ 64,630	$ 219,358	$ 918,660
	2010	825,000	29,671	--	--	567,311	69,423	341,758	1,833,163
	2009	825,000	--	--	--	507,705	69,885	6,595,041	7,997,631
Bertrand A. Valdman Former Senior Vice President and Former Chief Financial Officer (11)	2011	$ 96,771	$ --	$ --	$ --	$395,003	$ 197,178	$ 21,764	$ 710,716
	2010	395,000	--	--	--	586,733	247,187	47,163	1,276,083
	2009	395,000	--	--	--	154,429	158,380	373,521	1,081,330

1 *For 2011, reflects annual cash incentive compensation paid under the 2011 Goals and Incentive Plan, cash incentive compensation paid under the LTI Plan for the 2009-2011 performance cycle and the second and final year of merger performance bonuses payable to each of the executives, except Mr. Doyle and Mr. Reynolds who were not eligible for a merger performance bonus. Cash incentive amounts were paid in early 2012 or deferred at the executive's election. The 2011 Goals and Incentive Plan and the LTI Plan are described in further detail under "Compensation Discussion and Analysis," including the individual amounts paid to each Named Executive Officer in early 2012. Merger performance bonus amounts were: Ms. Harris, $680,000; Mr. Markell, $360,000; Ms. McLain, $284,625; Mr. Wiegand, $260,022; Ms. Mellies, $243,225; Mr. Gaines, $212,175; and Mr. Valdman, $395,003. LTI Plan amounts paid to Mr. Reynolds are described in footnote 10 below.*

2 *Reflects the aggregate increase in the actuarial present value of the executive's accumulated benefit under all pension plans during the year. The amounts are determined using interest rate and mortality rate assumptions consistent with those used in the Company's financial statements and include amounts which the executive may not currently be entitled to receive because such amounts are not vested. Information regarding these pension plans is set forth in further detail under "2011 Pension Benefits." Mr. Reynolds did not participate in the SERP, and his accumulated benefit shown is only from the qualified pension plan. The change in pension value amounts for 2011 are: Ms. Harris, $855,408; Mr. Doyle, $6,685; Mr. Markell, $473,602; Ms. McLain, $281,439; Mr. Wiegand, $306,042; Ms. Mellies, $166,862; Mr. Gaines, $193,576; Mr. Reynolds, $52,350; and Mr. Valdman, $196,888. Also included in this column are the portions of Deferred Compensation Plan earnings that are considered above market. These amounts for 2011 are: Ms. Harris, $2,210; Mr. Doyle, $0; Mr. Markell, $3,580; Ms. McLain, $8,259; Mr. Wiegand, $669; Ms. Mellies, $248; Mr. Gaines, $2,360; Mr. Reynolds, $12,280; and Mr. Valdman, $290. See the "2011 Nonqualified Deferred Compensation" table for all Deferred Compensation Plan earnings.*

3 *All Other Compensation for 2011 is shown in detail in the table below.*

4 *Ms. Harris was promoted to President and CEO from President on March 1, 2011.*

5 *Mr. Doyle joined PSE and Puget Energy as Senior Vice President and Chief Financial Officer on November 28, 2011.*

6 *Mr. Markell was appointed Senior Vice President and Chief Strategy Officer in February 2011 and ceased service as Chief Financial Officer at that time. Mr. Markell retired effective January 1, 2012.*

7 *Ms. McLain has worked at PSE since April 1988.*

8 *Mr. Wiegand has worked at PSE since June 1977.*

9 *Ms. Mellies has worked at PSE since October 2005.*

10 *Mr. Reynolds retired as CEO on March 1, 2011. Mr. Reynolds received pro-rata payments of his 2009-2011 and 2010-2012 LTI Plan grants following his retirement, $316,030 and $150,204 respectively. The total of these payments is shown in the Non-Equity Incentive Plan Compensation column.*

11 *Mr. Valdman voluntarily resigned on March 11, 2011.*

Detail of All Other Compensation

NAME	PERQUISITES AND OTHER PERSONAL BENEFITS [1]	TAX REIMBURSEMENTS	PAYMENTS/ ACCRUALS ON TERMINATION PLANS	REGISTRANT CONTRIBUTIONS TO DEFINED CONTRIBUTION AND DEFERRED COMPENSATION PLANS [2]	OTHER [3]
Kimberly J. Harris	$ 3,653	$ --	$ --	$ 17,150	$ 4,584
Daniel A. Doyle	0	--	--	1,432	159,314
Eric M. Markell	3,895	--	--	35,013	6,281
Susan McLain	0	--	--	26,192	6,111
Paul M. Wiegand	3,829	--	--	24,208	6,183
Marla D. Mellies	1,235	--	--	21,107	2,246
Donald E. Gaines	3,523	--	--	19,394	1,700
Stephen P. Reynolds	848	--	--	217,056	1,454
Bertrand A. Valdman	912	--	--	19,760	1,092

1 *Annual reimbursement for financial planning, tax planning, and/or legal planning, up to a maximum of $5,000 for Ms. Harris and $2,500 for the other Named Executive Officers. Club use is primarily for business purposes, but Company club expense is included when the executive is also able to use the club for personal use. Expenses for personal club use are directly paid by the executive, not PSE.*

2 *Includes Company contributions during 2011 to PSE's Investment Plan (a tax qualified 401(k) plan) and the Deferred Compensation Plan. For Mr. Reynolds, this includes the Company contribution to the Deferred Compensation Plan equal to 15% of Mr. Reynolds' base salary and annual incentive for the prior year, $199,906, which is described in more detail in the "2011 Nonqualified Deferred Compensation" section. Other Company contributions to the Deferred Compensation Plan are as follows: Ms. Harris, $0; Mr. Doyle, $0; Mr. Markell, $18,478; Ms. McLain, $14,679; Mr. Wiegand, $9,360; Ms. Mellies, $3,975; Mr. Gaines, $4,687; Mr. Reynolds, $0; and Mr. Valdman, $2,610. Company 401(k) contributions are as follows: Ms. Harris, $17,150; Mr. Doyle, $1,432; Mr. Markell, $16,535; Ms. McLain, $11,513; Mr. Wiegand, $14,848; Ms. Mellies, $17,132; Mr. Gaines, $14,707; Mr. Reynolds, $17,150; and Mr. Valdman, $17,150.*

3 *Reflects the value of imputed income for life insurance and Company paid premiums on supplemental disability insurance. For Mr. Doyle, includes $159,905 in payments related to relocation.*

2011 Grants of Plan-Based Awards

The following table presents information regarding 2011 grants of non-equity annual incentive awards and LTI Plan awards, including, as applicable, the range of potential payouts for the awards. Mr. Reynolds did not receive grants in either plan. Mr. Valdman received grants, but forfeited them when he resigned.

			Estimated Future Payouts under Non-Equity Incentive Plan Awards			
Name	Grant Date	Number of Units Granted	Threshold	Target	Maximum
Kimberly J. Harris					
Annual Incentive [1]	1/1/2011		$ 214,200	$ 612,000	$ 1,224,000
LTI Plan 2011-2013 [2,4]	3/4/2011	36,213	367,200	1,719,631	3,294,944
Daniel A. Doyle					
Annual Incentive [1]	n/a	n/a			
LTI Plan 2011-2013 [2,4]	At hire	8,474.10	$ 143,312	$ 402,406	$ 675,205
Eric M. Markell					
Annual Incentive [1]	1/1/2011		$ 77,700	$ 222,000	$ 444,000
LTI Plan 2011-2013 [2]	3/4/2011	12,041.40	203,500	571,805	959,442
Susan McLain					
Annual Incentive [1]	1/1/2011		$ 46,305	$ 132,300	$ 264,600
LTI Plan 2011-2013 [2,4]	3/4/2011	8,263.40	139,650	392,396	658,409
Paul M. Wiegand					
Annual Incentive [1]	1/1/2011		$ 42,525	$ 121,500	$ 243,000
LTI Plan 2011-2013 [2,4]	3/4/2011	7,588.80	128,251	360,366	604,665
Marla D. Mellies					
Annual Incentive [1]	1/1/2011		$ 41,738	$ 119,250	$ 238,500
LTI Plan 2011-2013 [2,4]	3/4/2011	7,448.20	125,875	353,689	593,462
Donald E. Gaines					
Annual Incentive [1]	1/1/2011		$ 30,940	$ 88,400	$ 176,800
LTI Plan 2011-2013 [2,4]	3/4/2011	3,269.20	55,249	155,243	260,485
Bertrand A. Valdman					
Annual Incentive [3]	1/1/2011		$ 82,950	$ 237,000	$ 474,000
LTI Plan 2011-2013 [2, 3]	3/4/2011	13,994.10	236,500	664,532	1,115,031

1 *As described in the "Compensation Discussion and Analysis," the 2011 Goals and Incentive Plan had dual funding triggers in 2011 of $882.9 million EBITDA and SQI performance of 6/9. Payment would be $0 if either trigger is not met. The threshold estimate assumes $882.9 million EBITDA and SQI performance at 6/9. The target estimate assumes $981.0 million EBITDA and SQI performance at 9/9. The maximum estimate assumes $1,324.35 million EBITDA or higher and SQI performance at 9/9. Mr. Doyle joined PSE in November 2011 and was not eligible to participate in the 2011 Goals and Incentive Plan.*

2 *As described in the "Compensation Discussion and Analysis," LTI Plan grants were allocated between an SQI component and a Total Return component. Payments are calculated based on the average three-year performance of SQIs and Total Return at Puget Holdings LLC and the unit value at the end of the performance cycle. Threshold estimate assumes that SQI results average 80% achievement, Total Return is below 10%, and ending unit value is $33.80. Target estimate assumes that SQI results average 90%, Total Return averages 12%, and ending unit value is $47.49. Maximum estimate assumes that SQI results average 100%, Total Return averages 15%, and ending unit value is $51.41.*

3 *Mr. Valdman voluntarily resigned in March 2011 and per the terms of the plans forfeited his non-vested grants, including the grants shown here.*

4 *As described in the "Compensation Discussion and Analysis," LTI Plan grants were awarded for the 2012-2014 plan cycle, with the following target number of units and at grant values (calculated as the target number of units multiplied by $36.03 per unit value). Ms. Harris, 38,690, $1,394,000; Mr. Doyle, 11,865, $427,496; Ms. McLain, 7,987, $287,772; Mr. Wiegand, 7,617, $274,441; Ms. Mellies, 7,198, $259,344; and Mr. Gaines, 3,190, $114,936.*

2011 Pension Benefits

The Company and its affiliates maintain two pension plans: the Retirement Plan and the SERP. The following table provides information for each of the Named Executive Officers regarding the actuarial present value of the executive's accumulated benefit and years of credited service under the Retirement Plan and the SERP. The present value of accumulated benefits was determined using interest rate and mortality rate assumptions consistent with those used in the Company's financial statements. Except as described below in footnote 1, relating to Mr. Reynolds, each of the Named Executive Officers participates in both plans.

NAME	PLAN NAME	NUMBER OF YEARS CREDITED SERVICE	PRESENT VALUE OF ACCUMULATED BENEFIT [2,3]	PAYMENTS DURING LAST FISCAL YEAR
Kimberly J. Harris	PSE Retirement Plan	12.7	$ 221,799	$ --
	PSE SERP	12.7	1,893,375	--
Daniel A. Doyle	PSE Retirement Plan	0.1	1,907	--
	PSE SERP	0.1	4,778	--
Eric M. Markell	PSE Retirement Plan	9.4	228,958	--
	PSE SERP	9.4	1,837,574	--
Susan McLain	PSE Retirement Plan	23.7	381,504	--
	PSE SERP	23.7	1,576,260	--
Paul M. Wiegand	PSE Retirement Plan	34.5	552,081	--
	PSE SERP	34.5	1,441,598	--
Marla D. Mellies	PSE Retirement Plan	6.2	115,658	--
	PSE SERP	6.2	430,110	--
Donald E. Gaines	PSE Retirement Plan	30.9	492,108	--
	PSE SERP	30.9	822,025	--
Stephen P. Reynolds [1]	PSE Retirement Plan	9.2	261,205	--
	PSE SERP	n/a	n/a	n/a
Bertrand A. Valdman	PSE Retirement Plan	7.3	147,806	--
	PSE SERP	7.3	923,398	--

1 *Mr. Reynolds participated in the Retirement Plan, but not the SERP. In lieu of participating in the SERP, each year Mr. Reynolds' account under the Deferred Compensation Plan was credited with an amount equal to 15% of his base salary and annual incentive for the preceding year. The value of this deferred compensation account at December 31, 2011 of $881,207 is also shown in the "2011 Nonqualified Deferred Compensation Plan" table.*

2 *The amounts reported in this column for each executive were calculated assuming no future service or pay increases. Present values were calculated assuming no pre-retirement mortality or termination. The values under the Retirement Plan and the SERP are the actuarial present values as of December 31, 2011 of the benefits earned as of that date and payable at normal retirement age (age 65 for the Retirement Plan and age 62 for the SERP). Future cash balance interest credits are 4.0% for 2012 and are assumed to average 5.0% annually thereafter. The discount assumption is 4.75%, and the post-retirement mortality assumption is based on the 2012 417(e) unisex mortality table. Annuity benefits are converted to lump sum amounts at retirement based on assumed future 417(e) segment rates of 2.06%, 5.25% and 6.32% (the 24 month average of the underlying rates as of September 2011). These assumptions are consistent with the ones used for the Retirement Plan and the SERP for financial reporting purposes for 2011. In order to determine the change in pension values for the "Summary Compensation" table, the values of the Retirement Plan and the SERP benefits were also calculated as of December 31, 2010 for the benefits earned as of that date using the assumptions used for financial reporting purposes for 2010. These assumptions included assumed average cash balance interest credits of 4.0% for 2011 and 5.5% for all future years, a discount assumption of 5.15% and post-retirement mortality assumption based on the 2011 417(e) unisex mortality table. Annuity benefits were converted to lump sum amounts at retirement based on assumed future 417(e) segment rates of 3.78%, 6.31% and 6.57% (the 24 month average of the underlying rates as of September 2010). Other assumptions used to determine the value as of December 31, 2010 were the same as those used for December 31, 2011.*

3 *As described in footnote 2 above, the amounts reported for the SERP in this column are actuarial present values, calculated using the actuarial assumptions used for financial reporting purposes. These assumptions are different from those used to calculate the actual amount of benefit payments under the SERP (see text below for a discussion of the actuarial assumptions used to calculate actual payment amounts). The following table shows the estimated lump sum amount that would be paid under the SERP to each SERP-eligible Named Executive Officer at age 62 (without discounting to the present), calculated as if such Named Executive Officer had terminated employment on December 31, 2011. Each SERP-eligible Named Executive Officer (except Dan Doyle) was vested in his or her SERP benefits as of December 31, 2011.*

NAME	LUMP SUM
Kimberly J. Harris	$ 3,682,230
Daniel A. Doyle	7,116
Eric M. Markell	1,970,044
Susan McLain	2,147,771
Paul M. Wiegand	1,650,543
Marla D. Mellies	692,082
Donald E. Gaines	1,146,362
Bertrand A. Valdman	1,694,613

Retirement Plan

Under the Retirement Plan, Puget Energy's and PSE's eligible salaried employees, including the Named Executive Officers, accrue benefits in accordance with a cash balance formula, beginning on the later of their date of hire or March 1, 1997. Under this formula, for each calendar year after 1996, age-weighted pay credits are allocated to a bookkeeping account (a Cash Balance Account) for each participant. The pay credits range from 3% to 8% of eligible compensation. Eligible compensation generally includes base salary and bonuses (other than bonuses paid under the LTI Plan and signing, retention and similar bonuses), up to the limit imposed by the Internal Revenue Code. For 2009 through 2011, the Internal Revenue Code compensation limit was $245,000. In addition, as of March 1, 1997, the Cash Balance Account of each participant who was participating in the Retirement Plan on March 1, 1997 was credited with an amount based on the actuarial present value of that participant's accrued benefit, as of February 28, 1997, under the Retirement Plan's previous formula.

Amounts in the Cash Balance Accounts are also credited with interest. The interest crediting rate is 4% per year or such higher amount as PSE may determine. For 2011 and 2012 the annual interest crediting rate was 4%.

A participant's Retirement Plan benefit generally vests upon the earlier of the participant's completion of three years of active service with Puget Energy, PSE or their affiliates or attainment of age 65 (the Retirement Plan's normal retirement age) while employed by the Company or one of its affiliates. Normal retirement benefit payments begin to a vested participant as of the first day of the month following the later of the participant's termination of employment or attainment of age 65. However, a vested participant may elect to have his or her benefit under the Retirement Plan paid, or commence to be paid, as of the first day of any month commencing after the date on which his or her employment with Puget Energy, PSE and their affiliates terminates. If benefit payments commence prior to the participant's attainment of age 65, then the amount of the monthly payments will be reduced for early commencement to reflect the fact that payments will be made over a longer period of time. This reduction is subsidized — that is, it is less than a pure actuarial reduction. The amount of this reduction is, on average, 0.30% for each of the first 60 months, 0.33% for each of the second 60 months, 0.23% for each of the third 60 months and 0.17% for each of the fourth 60 months that the payment commencement date precedes the participant's 65th birthday. Further reductions apply for each additional month that the payment commencement date precedes the participant's 65th birthday. As of December 31, 2011, all the Named Executive Officers, except Mr. Doyle, were vested in their benefits under the Retirement Plan and, hence, would be eligible to commence benefit payments upon termination.

The normal form of benefit payment for unmarried participants is a straight life annuity providing monthly payments for the remainder of the participant's life, with no death benefits. The straight life annuity payable on or after the participant's normal retirement age is actuarially equivalent to the balance in the participant's Cash Balance Account as of the date of distribution. For married participants, the normal form of benefit payment is an actuarially equivalent joint and 50% survivor annuity with a "pop-up" feature providing reduced monthly payments (as compared to the straight life annuity) for the remainder of the participant's life and, upon the participant's death, monthly payments to the participant's surviving spouse for the remainder of the spouse's life in an amount equal to 50% of the amount being paid to the participant. Under the pop-up feature, if the participant's spouse predeceases the participant, the participant's monthly payments increase to the level that would have been provided under the straight life annuity. In addition, the Retirement Plan provides several other annuity payment options and a lump sum payment option that can be elected by participants. All payment options are actuarially equivalent to the straight life annuity. However, in no event will the amount of the lump sum payment be less than the balance in the participant's Cash Balance Account as of the date of distribution (in some instances the amount of the lump sum distribution may be greater than the balance in the Cash Balance Account due to differences in the mortality table and interest rates used to calculate actuarial equivalency).

If a participant in the cash balance portion of the Retirement Plan dies while employed by the Company or any of its affiliates, then his or her Retirement Plan benefit will be immediately vested. If a vested participant dies before his or her Retirement Plan benefit is paid, or commences to be paid, then the participant's Retirement Plan benefit will be paid to his or her beneficiary(ies). If a participant dies after his or her Retirement Plan benefit has commenced to be paid, then any death benefit will be governed by the form of payment elected by the participant.

Supplemental Executive Retirement Plan

The SERP provides a benefit to participating Named Executive Officers that supplements the retirement income provided to the executives by the Retirement Plan. Ms. Harris, Mr. Doyle, Mr. Markell, Ms. McLain, Mr. Wiegand, Ms.

Mellies, and Mr. Gaines participate in the SERP. Mr. Valdman participated in the SERP prior to his voluntary resignation. Mr. Reynolds did not participate in the SERP prior to his retirement.

A participating Named Executive Officer's SERP benefit generally vests upon the executive's completion of five years of participation in the SERP while employed by the Company or any of its affiliates. All the participating Named Executive Officers, except Mr. Doyle, are vested in their SERP benefits. Mr. Valdman voluntarily resigned in March 2011 and will be entitled to receive his SERP benefit beginning at age 62. The monthly benefit payable under the SERP to a vested executive (calculated in the form of a straight life annuity payable for the executive's lifetime commencing at the later of the executive's date of termination or attainment of age 62) is equal to (1) below minus the sum of (2) and (3) below:

(1) One-twelfth (1/12) of the executive's highest average earnings times the executive's years of credited service (not in excess of 15) times 3-1/3%. For purposes of the SERP, "highest average earnings" means the average of the executive's highest three calendar years of earnings. The three calendar years do not have to be consecutive, but they must be among the last ten calendar years completed by the executive prior to his or her termination. "Earnings" for this purpose include base salary and annual bonus, but do not include long-term incentive compensation. An executive will receive one "year of credited service" for each consecutive 12-month period he or she is employed by the Company or its affiliates. If an executive becomes entitled to disability benefits under PSE's long-term disability plan, then the executive's highest average earnings will be determined as of the date the executive became disabled, but the executive will continue to accrue years of credited service until he or she begins to receive SERP benefits.

(2) The monthly amount payable (or that would be payable) under the Retirement Plan to the executive in the form of a straight life annuity commencing as of the first day of the month following the later of the executive's date of termination or attainment of age 62, and includes amounts previously paid or segregated pursuant to a qualified domestic relations order.

(3) The actuarially equivalent monthly amount payable (or that would be payable) to the executive as of the first day of the month following the later of the executive's date of termination or attainment of age 62 from any pension-type rollover accounts within the Deferred Compensation Plan (including the Annual Cash Balance Restoration Account). These accounts are described in more detail in the "2010 Nonqualified Deferred Compensation" section.

Normal retirement benefits under the SERP generally are paid or commence to be paid within 90 days following the later of the Named Executive Officer's termination of employment or attainment of age 62. Except as provided below, SERP benefits are normally paid in a lump sum that is equal to the actuarial present value of the monthly straight life annuity benefit. In lieu of the normal form of payment, an executive may elect to receive his or her SERP benefit in the form of monthly installment payments over a period of two to 20 years, in a straight life annuity or in a joint and survivor annuity with a 100%, 75%, 50% or 25% survivor benefit. All payment options are actuarially equivalent to the straight life annuity. Mr. Markell, Ms. McLain, and Mr. Wiegand are the only Named Executive Officers eligible for early retirement benefit payments under the SERP as of December 31, 2011.

If a participating Named Executive Officer dies while employed by Puget Energy, PSE or any of their affiliates or after becoming vested in his or her SERP benefit, but before his or her SERP benefit has commenced to be paid, then the executive's surviving spouse will receive a lump sum benefit equal to the actuarial equivalent of the survivor benefit such spouse would have received under the joint and 50% survivor annuity option. This amount will be calculated assuming the executive would have commenced benefit payments in that form on the first day of the month following the later of his or her death or attainment of age 62, with any applicable reductions for early commencement if the executive dies before age 62. If the executive is not married, then no death benefit will be paid. If an executive dies after his or her SERP benefit has commenced to be paid, then any death benefit will be governed by the form of payment elected by the executive.

2011 Nonqualified Deferred Compensation

The following table provides information for each of the Named Executive Officers regarding aggregate executive and Company contributions and aggregate earnings for 2011 and year-end account balances under the Deferred Compensation Plan.

NAME	EXECUTIVE CONTRIBUTIONS IN 2011 [1]	REGISTRANT CONTRIBUTIONS IN 2011 [2]	AGGREGATE EARNINGS IN 2011 [3]	AGGREGATE WITHDRAWALS/ DISTRIBUTIONS	AGGREGATE BALANCE AT DECEMBER 31, 2011 [6]
Kimberly J. Harris	$ --	$ --	$ 12,921	$ --	$ 253,442
Daniel A. Doyle	--	--	--	--	--
Eric M. Markell	26,916	18,478	21,145	--	448,278
Susan McLain	38,899	14,679	48,297		978,209
Paul M. Wiegand	12,510	9,360	24,264		459,866
Marla D. Mellies	3,856	3,975	1,449		35,474
Donald E. Gaines	4,898	3,484	16,218	--	310,966
Stephen P. Reynolds[4]	--	199,906	93,522	3,393,974 [4]	881,207
Bertrand A. Valdman [5]	6,580	2,610	4,169	365,597 [5]	--

1 *The amount in this column reflects elective deferrals by the executive of salary, annual incentive compensation or LTI Plan awards paid in 2011. Deferred salary amounts are: Ms. Harris, $0; Mr. Doyle, $0; Mr. Markell, $24,637; Ms. McLain, $34,251; Mr. Wiegand, $12,510; Ms. Mellies, $3,856; Mr. Gaines, $6,529; Mr. Reynolds, $0; and Mr. Valdman, $2,475. Deferred incentive compensation amounts are: Ms. Harris, $0; Mr. Doyle, $0; Mr. Markell, $2,280; Ms. McLain, $4,648; Mr. Wiegand, $0; Ms. Mellies, $0; Mr. Gaines, $0; Mr. Reynolds, $0; and Mr. Valdman, $4,105. The amounts are also included in the applicable column of the "Summary Compensation" table for 2011.*

2 *The amount reported in this column reflects contributions by PSE consisting of the Annual Investment Plan Restoration Amount and Annual Cash Balance Restoration Amount described below. For Mr. Reynolds, the amount also includes $199,906 in additional contributions by PSE to the Deferred Compensation Plan in lieu of Mr. Reynolds' participation in the SERP. These amounts are also included in the total amounts shown in the All Other Compensation column of the "Summary Compensation" table for 2011.*

3 *The amount in this column for each executive reflects the change in value of investment tracking funds. Above market earnings on these amounts are included in the Change in Pension Value and Nonqualified Deferred Compensation Earnings column of the "Summary Compensation" table for 2011.*

4 *Mr. Reynolds retired on March 1, 2011 and received a distribution of a portion of his deferred account, per his prior election. The December 31, 2011 balance shown for Mr. Reynolds will be distributed in accordance with his prior election.*

5 *Mr. Valdman voluntarily resigned in March 2011 and per the terms of the plan for a participant not eligible for retirement, received a distribution of the entire account balance.*

6 *Of the amounts in this column, the following amounts have also been reported in the "Summary Compensation" table for 2011, 2010, and 2009.*

NAME	REPORTED FOR 2011	REPORTED FOR 2010	REPORTED FOR 2009
Kimberly J. Harris	$ 2,210	$ 1,979	$ 3,671
Daniel A. Doyle	--	--	--
Eric M. Markell	48,974	46,901	58,122
Susan McLain	61,837	--	--
Paul M. Wiegand	22,539	--	--
Marla D. Mellies	8,079	--	--
Donald E. Gaines	13,576	10,880	--
Stephen P. Reynolds	212,186	428,218	512,237
Bertrand A. Valdman	9,480	48,295	63,211

Deferred Compensation Plan

The Named Executive Officers are eligible to participate in the Deferred Compensation Plan and may defer up to 100% of base salary, annual incentive compensation and LTI Plan grants. In addition, each year, executives are eligible to receive Company contributions to restore benefits not available to them under the Company's tax-qualified plans due to limitations imposed by the Internal Revenue Code. The Annual Investment Plan Restoration Amount equals the additional matching and any other employer contribution under the 401(k) plan that would have been credited to an electing executive's 401(k) plan account if the Internal Revenue Code limitations were not in place and if deferrals under the Deferred Compensation Plan were instead made to the 401(k) plan. The Annual Cash Balance Restoration Amount equals the actuarial equivalent of any reductions in an executive's accrued benefit under the Retirement Plan due to Internal Revenue Code limitations or as a result of deferrals under the Deferred Compensation Plan. An executive must generally be employed on the last day of the year to receive these Company contributions, unless he or she retires or dies during the year in which case the Company will contribute a prorated amount.

Mr. Reynolds did not participate in the SERP during his tenure with PSE. In lieu of such participation, each year Mr. Reynolds' account under the Deferred Compensation Plan was credited with an amount equal to 15% of Mr. Reynolds' base salary and annual bonus for the preceding year. Mr. Reynolds' last credit was in January 2011 for 2010 salary and annual bonus.

The Named Executive Officers choose how to credit deferred amounts among three investment tracking funds. The tracking funds mirror performance in major asset classes of bonds, stocks, and interest crediting. The tracking funds differ from the investment funds offered in the 401(k) plan. The 2011 calendar year returns of these tracking funds were:

Vanguard Total Bond Market Index	7.72%
Vanguard 500 Index	1.97%
Interest Crediting Fund	5.41%

The Named Executive Officers may change how deferrals are allocated to the tracking funds at any time. Changes generally become effective as of the first trading day of the following calendar quarter.

The Named Executive Officers generally may choose how and when to receive payments under the Deferred Compensation Plan. There are three types of in-service withdrawals. First, an executive may choose an interim payment of deferred amounts by designating a plan year for payment at the time of his or her deferral election. The interim payment is made in a lump sum within 60 days after the last day of the designated plan year, which must be at least two years following the plan year of the deferral. Second, an in-service withdrawal may also be made to an executive upon a qualifying hardship event and demonstrated need. Third, only with respect to amounts deferred and vested prior to 2005, the executive may elect an in-service withdrawal for any reason by paying a 10% penalty. Payments upon termination of employment depend on whether the executive is then eligible for retirement. If the executive's termination occurs prior to his or her retirement date (generally the earlier of attaining age 62 or age 55 with five years of credited service), the executive will receive a lump sum payment of his or her account balance. If the executive's termination occurs after his or her retirement date, the executive may choose to receive payments in a lump sum or via one of several installment options (fixed amount, specified amount, annual or monthly installments, of up to 20 years). Mr. Markell, Ms. McLain and Mr. Wiegand are the only Named Executive Officers currently retirement eligible under the Deferred Compensation Plan.

Potential Payments Upon Termination or Change in Control

The "Estimated Potential Incremental Payments Upon Termination or Change in Control" table reflects the estimated amount of incremental compensation payable to each of the Named Executive Officers in the event of (i) an involuntary termination without cause or by the executive for good reason not in connection with a change in control; (ii) a change in control; (iii) an involuntary termination without cause or for good reason in connection with a change in control; (iv) retirement; (v) disability; or (vi) death. Mr. Reynolds retired March 1, 2011 and Mr. Valdman voluntarily resigned in March 2011. Neither were entitled to any termination or change in control benefits in connection with their terminations of employment, except that Mr. Reynolds was entitled to a pro-rated payment under the LTI Plan in accordance with its terms.

Certain Company benefit plans provide incremental benefits or payments in the event of certain terminations of employment. In addition, each Named Executive Officer, other than Mr. Doyle and Mr. Reynolds, entered into an Amended and Restated Executive Employment Agreement with the Company in March 2009, which provides for benefits or payments upon certain terminations of employment from the Company following the 2009 merger or a subsequent change in control. The only benefit payable to the Named Executive Officers solely upon a change in control is accelerated vesting of LTI Plan awards, described below.

Disability and Life Insurance Plans

If a Named Executive Officer's employment terminates due to disability or death, the executive or his or her estate will receive benefits under the PSE disability plan or life insurance plan available generally to all salaried employees. These disability and life insurance amounts are not reflected in the table below. The Named Executive Officer is also eligible to receive supplemental disability and life insurance. The supplemental monthly disability coverage is 65% of monthly base salary and target incentive pay, reduced by (i) amounts receivable under the PSE disability plan generally available to salaried employees and (ii) certain other income benefits. The supplemental life insurance benefit is provided at two times base salary and target annual incentive bonus if the executive dies while employed by PSE with a reduction for amounts payable under the applicable group life insurance policy.

LTI Plan Awards

If a Named Executive Officer's employment terminates due to disability or death, the executive or his or her estate will be paid a pro-rata portion of LTI Plan awards that were granted in a prior year. In the case of retirement at normal retirement age or approved early retirement, pro-rata LTI Plan awards will be paid in the first quarter following the year of retirement, based on performance through the prior year. In the event of a change in control, outstanding LTI Plan awards will be paid at the higher of (i) target performance or (ii) actual performance achieved during the performance cycle ending with the fiscal quarter that precedes the change of control.

Employment Agreement with Mr. Reynolds

Puget Energy and Puget Sound Energy (together, the "Company") entered into an employment agreement with Mr. Reynolds as of January 1, 2002 to secure his services as Chief Executive Officer and President. The agreement had an initial term of three years after which time it automatically renewed for one-year terms unless notice of termination was given by either party at least 180 days prior to the expiration of the then current term, which notice of termination Mr. Reynolds provided in June 2010. Effective as of December 31, 2009, Mr. Reynolds agreed to waive all change in control payments and benefits that may otherwise be payable to him on or after December 31, 2009 and for which he was previously eligible under his employment agreement. During the term of the employment agreement, if the Company had terminated Mr. Reynolds' employment without cause, or Mr. Reynolds had terminated his employment with good reason, Mr. Reynolds would have received an amount equal to two times his then current annual base salary and target annual incentive bonus. Mr. Reynolds' employment agreement terminated in connection with his retirement as CEO effective March 1, 2011, subject to the continuing obligations described below. Other than the right to receive accrued amounts under the Retirement Plan and the Deferred Compensation Plan, Mr. Reynolds received no severance or other payments in connection with his termination.

The employment agreement contains a noncompetition covenant pursuant to which Mr. Reynolds commits that during his employment with the Company and for a period of two years following his voluntary termination without good reason, he will not perform services for any person or entity selling or distributing electric power or natural gas in Washington, Oregon or Idaho, unless the Company consents in writing. The Company may enforce this covenant through injunctive relief or other appropriate remedies. The employment agreement also contains an indemnification clause in favor of Mr. Reynolds. The Company commits to defend, indemnify and hold harmless Mr. Reynolds from all liabilities in connection with his service. As part of that commitment, the Company will cover Mr. Reynolds under the Company's directors' and officers' liability insurance for six years following his termination of employment, until March 1, 2017.

Employment Agreements with Other Named Executive Officers

In March 2009, PSE entered into Amended and Restated Executive Employment Agreements (Employment Agreements) with each of the Named Executive Officers except Mr. Doyle and Mr. Reynolds (collectively, the Covered Executives), the terms of which are the same for all the Covered Executives and which amended and restated existing Amended and Restated Change of Control Agreements between the Company and each of the Covered Executives. The Employment Agreements provide for an employment period of two years after the completion of the February 2009 merger (Employment Period) and generally provide benefits similar to those provided under the previous Change of Control Agreements. In the event of termination of employment prior to the second anniversary of the merger or termination of employment within two years of a change in control that occurs after the Employment Period has ended (each, a Covered Termination), a Covered Executive is eligible to receive the payments described below. A change in control generally means a person (or group of persons) (with certain exceptions set forth in the Employment Agreements) acquires (i) beneficial ownership of more than 55% of the total combined voting power of the Company's securities outstanding immediately after such acquisition (other than through a registered public offering) or (ii) all or substantially all of the Company's assets.

Payments upon Involuntary Termination without Cause or for Good Reason

If a Covered Executive's employment is terminated without cause by the Company or is terminated by the Covered Executive for good reason during the Employment Period, or within two years of a change in control that follows the Employment Period, the Covered Executive is eligible to receive the following compensation and benefits:

- Three times the sum of annual base salary and annual incentive bonus for the year in which termination occurs;

- Pro-rated annual incentive bonus for the year in which termination occurs (Annual Bonus). Since this amount was earned for 2011, no amount is shown in the table below;

- Supplemental retirement benefit equal to the difference between (x) the actuarial equivalent of the amount the Covered Executive would have received under the Retirement Plan and the SERP had his or her employment continued until the end of the Employment Period, and (y) the actuarial equivalent of the amount the Covered Executive actually receives or is entitled to receive under the Retirement Plan and SERP;

- Merger performance bonus equal to the amount the Covered Executive would have received had his or her employment continued until each of the first and second anniversaries of the merger. In the event of termination after the first anniversary of the merger but on or prior to the second anniversary of the merger, the Covered Executive is eligible to receive the merger performance bonus that would have been payable as of the second anniversary. The merger performance bonuses have been fully paid as of December 31, 2011 so no amount is shown in the table below; and

- Continued group medical, dental, disability and life insurance benefits to the Covered Executive and his or her family. Benefits will be paid by the Company while the Covered Executive is eligible for COBRA and thereafter by reimbursement of payments made by the Covered Executive for such coverage (including related tax amounts), except that if the Covered Executive becomes re-employed with another employer and is eligible to receive medical or other welfare benefits under another employer-provided plan, the medical and other welfare benefits under the Employment Agreement will become secondary to those provided by the other employer (the foregoing benefit is referred to as Health and Welfare Benefit Continuation).

Under the Employment Agreements, "cause" and "good reason" have the following meanings:

Cause generally means (i) the willful and continued failure by the Covered Executive to substantially perform the Covered Executive's duties with the Company (other than any such failure resulting from incapacity due to physical or mental illness) for a period of 30 days after written notice of demand for substantial performance has been delivered to the Covered Executive or (ii) the Covered Executive's willfully engaging in gross misconduct materially and demonstrably injurious to the Company, as determined by the Board after notice to the executive and opportunity for a hearing. No act or failure to act on the Covered Executive's part is considered "willful" unless the Covered Executive has acted or failed to act with an absence of good faith and without a reasonable belief that the Covered Executive's action or failure to act was in the best interests of the Company.

Good Reason generally means (i) the assignment of the Covered Executive to a non-officer position with the Company, which the parties agree would constitute a material reduction in the Covered Executive's authority, duties or responsibilities; (ii) a material diminution in the Covered Executive's total compensation opportunities under the Employment Agreement; (iii) the Company's requiring the Covered Executive to be based at any location that represents a material change from the Covered Executive's location in the Seattle/Bellevue metropolitan area, unless the Covered Executive consents to the relocation; or (iv) a material breach of the Employment Agreement by the Company, provided that, in any of the foregoing, the Company has not remedied the alleged violation(s) within 60 days of notice from the Covered Executive.

Payments upon Retirement, Disability or Death

In the event of a Covered Termination due to voluntary retirement after having attained age 55 with a minimum of five years of service to the Company, a pro-rated Annual Bonus is payable to the Covered Executive. The bonus is payable at the time the Covered Executive otherwise would have received the payment had employment continued, based on the Company's actual achievement of performance goals.

In the event of a Covered Termination due to disability or death, the Covered Executive is eligible to receive the following compensation and benefits:

- Pro-rated Annual Bonus; and
- Health and Welfare Benefit Continuation.

In addition, upon termination for any of the foregoing reasons during the Employment Period, other than by reason of retirement, the Covered Executive is eligible to receive the perquisite of financial planning.

Except as otherwise described above, payments of salary and bonus will be paid after the date of termination, subject to the Covered Executive's timely execution of a general waiver and release of claims.

The Employment Agreements also contain noncompetition and anti-solicitation provisions that restrict the Covered Executive during the Employment Period and for twelve months thereafter from, respectively, engaging in activities related to selling or distributing electric power or natural gas in Washington or soliciting others to leave the Company or causing them to be hired from the Company by another entity. The Employment Agreements contain a non-disparagement clause and a confidentiality clause pursuant to which the Covered Executives must keep confidential all secret or confidential information, knowledge or data relating to the Company and its affiliates obtained during their employment. The Covered Executives may not disclose any such information, knowledge or data after their respective terminations of employment unless PSE consents in writing or as required by law.

If any payments paid or payable in connection with the February 2009 merger, whether paid or payable pursuant to the Employment Agreements or otherwise, are characterized as "excess parachute payments" within the meaning of Section 280G of the Internal Revenue Code, then the Company will make a cash payment to or on behalf of the Covered Executive equal to any excise taxes imposed by Section 4999 of the Internal Revenue Code on such payments, plus the income taxes payable by him or her resulting from this cash payment. If a change in control occurs subsequent to the merger while the Company's stock is not traded on an established securities market or otherwise immediately before such change in control, then the Covered Executive will agree to execute a waiver of any "excess parachute payments" that would result from such payments, provided that the Company agrees to seek, but is not required to obtain, shareholder approval of the amount payable in connection with termination of employment, in which case the waived amounts will be restored to the Covered Executive.

Estimated Potential Incremental Payments Upon Termination or Change in Control

The amounts shown in the table below assume that the termination of employment or change in control was effective as of December 31, 2011. The amounts below are estimates of the incremental amounts that would be paid out to the Named Executive Officer upon a termination of employment or change in control. Actual amounts payable can only be determined at the time of a termination of employment or change in control. Mr. Reynolds and Mr. Valdman were not employed by the Company on December 31, 2011 and were not eligible for any payments in connection with their terminations of employment.

	Involuntary Termination w/o Cause or for Good Reason	Upon Change in Control	After Change in Control Involuntary Termination w/o Cause or for Good Reason	Retirement	Disability	Death
Kimberly J. Harris						
Cash Severance (salary and/or annual incentive)	$ n/a	$ --	$ 3,996,000	$ --	$ --	$ --
Long Term Incentive Plan	--	2,666,260	2,666,260	--	663,578	663,578
SERP (additional years of credited service) [1]	--	--	980,781	--	--	--
Benefits (continuation) [2]	n/a	--	30,988	--	30,988	30,988
Supplemental Life Insurance	n/a	--	--	--	--	1,824,000
Total Estimated Incremental Value	$ n/a	$ 2,666,260	$ 7,674,029	$ --	$ 694,566	$ 2,518,566
Daniel A. Doyle						
Long Term Incentive Plan	$ --	$ --	$ 466,380	$ ----	$ 104,570	$ 104,570
SERP (additional years of credited service) [1]	--	--	--	--	--	--
Benefits (continuation) [2]	n/a	--	--	--	--	--
Supplemental Life Insurance	n/a	--	--	--	--	$ 855,000
Total Estimated Incremental Value	$ n/a	$ --	$ 466,380	$ --	$ 104,570	$ 959,570
Eric M. Markell						
Cash Severance (salary and/or annual incentive)	$ n/a	$ --	$ 1,776,000	$ --	$ --	$ --
Long Term Incentive Plan	--	1,361,534	1,361,534	460,802	460,802	460,802
SERP (additional years of credited service) [1]	--	--	473,434	--	--	--
Benefits (continuation) [2]	n/a	--	44,079	--	44,079	44,079
Supplemental Life Insurance	n/a	--	--	--	--	814,000
Total Estimated Incremental Value	$ n/a	$ 1,361,534	$ 3,655,047	$ 460,802	$ 504,881	$ 1,318,881
Susan McLain						
Cash Severance (salary and/or annual incentive)	$ n/a	$ --	$ 1,278,900	$ --	$ --	$ --
Long Term Incentive Plan	--	931,192	931,192	314,905	314,905	314,905
SERP (additional years of credited service) [1]	n/a	--	--	--	--	--
Benefits (continuation) [2]	n/a	--	24,488	--	24,488	24,488
Supplemental Life Insurance	n/a	--	--	--	--	558,600
Total Estimated Incremental Value	$ n/a	$ 931,192	$ 2,234,580	$ 314,905	$ 339,393	$ 897,993
Paul M. Wiegand						
Cash Severance (salary and/or annual incentive)	$ n/a	$ --	$ 1,174,500	$ --	$ --	$ --
Long Term Incentive Plan	--	742,859	742,859	233,287	233,287	233,287
SERP (additional years of credited service)[1]	n/a	--	0	--	--	--
Benefits (continuation) [2]	n/a	--	40,480	--	40,480	40,480
Supplemental Life Insurance	n/a	--	--	--	--	513,000
Total Estimated Incremental Value	$ n/a	$ 742,859	$ 1,957,839	$ 233,287	$ 273,767	$ 786,767
Marla D. Mellies						
Cash Severance (salary and/or annual incentive)	$ n/a	$ --	$ 1,152,750	$ --	$ --	$ --
Long Term Incentive Plan	--	610,283	610,283	--	187,920	187,920
SERP (additional years of credited service) [1]	n/a	--	288,064	--	--	--
Benefits (continuation) [2]	n/a	--	24,284	--	24,284	24,284
Supplemental Life Insurance	n/a	--	--	--	--	503,500
Total Estimated Incremental Value	$ n/a	$ 610,283	$ 2,075,381	$ --	$ 212,204	$ 715,704
Donald E. Gaines						
Cash Severance (salary and/or annual incentive)	$ n/a	$ --	$ 920,200	$ --	$ --	$ --
Long Term Incentive Plan	--	366,378	366,378	--	123,740	123,740
SERP (additional years of credited service) [1]	n/a	--	--	--	--	--
Benefits (continuation) [2]	n/a	--	27,325	--	27,325	27,325
Supplemental Life Insurance	n/a	--	--	--	--	397,800
Total Estimated Incremental Value	$ n/a	$ 366,378	$ 1,321,903	$ --	$ 151,065	$ 548,865

1 *SERP values are shown as the estimated incremental value that the Named Executive Officer would receive at age 62 as a result of the termination event shown in the column, relative to the vested benefit as of December 31, 2011. These values are based on interest rate and mortality rate assumptions consistent with those used in the Company's financial statements.*

2 *Benefits (continuation) reflects the value of continued medical, dental, disability and life insurance benefits as well as financial planning benefit in the amount of $5,000 for Ms. Harris and $2,500 for all other named executives.*

DIRECTOR COMPENSATION FOR FISCAL YEAR 2011

The following table sets forth information regarding compensation paid by the Company to the directors named in the table who received compensation from the Company in 2011 for service as directors. We refer to these directors as nonemployee directors. Directors who are employed by the Company or by the Company's investor-owners are not paid separately for their service and thus are not named in the table below. The directors who served in 2011 and were employed by the Company's investor-owners are: Andrew Chapman, Alan James, Alan Kadic, Christopher Leslie, Benjamin Hawkins, Mark Wiseman and Mark Wong, who is no longer a director. Stephen Reynolds was employed by the Company and also served as a director until his retirement on March 1, 2011. Kimberly Harris was employed by the Company and also served as a director beginning March 1, 2011.

As described in further detail below, the Company's nonemployee director compensation program in 2011 consisted of quarterly retainer cash fees of $20,000. Additional quarterly retainer amounts associated with serving as Chair of the Board, chairing Board committees, serving on the Audit Committee and meeting fees were also paid in cash.

NAME	FEES EARNED	NONQUALIFIED DEFERRED COMPENSATION EARNINGS [1]	TOTAL
William Ayer	$ 148,800	$ 3,815	$ 152,615
Herbert Simon	110,000	2,681	112,681
Christopher Trumpy	108,800	--	108,800
Mary O. McWilliams [2]	75,500	--	75,500

[1] *Represents earnings accrued to deferred compensation considered to be above market.*

[2] *Ms. McWilliams was appointed as a nonemployee director on March 1, 2011.*

Nonemployee Director Compensation Program. The 2011 nonemployee director compensation program is based on the principles that the level of nonemployee director compensation should be based on Board and committee responsibilities and should be competitive with comparable companies.

The 2011 compensation program for nonemployee directors was as follows:

- A base cash quarterly retainer fee of $20,000
- $1,600 for attendance at each in-person Board and committee meeting, and $800 for each telephonic meeting lasting 60 minutes or less,

In 2011, nonemployee directors were paid the following additional cash quarterly retainer fees:

- Independent Board Chairman, $10,000
- Chair of the Governance and Public Affairs Committees, $1,500
- Each member of the Audit Committee other than the chair, $1,000

Nonemployee directors were reimbursed for actual travel and out-of-pocket expenses incurred in connection with their services.

Nonemployee directors are eligible to participate in the Company's matching gift program on the same terms as all Puget Energy employees. Under this program, the Company matches up to a total of $300 a year in contributions by a director to non-profit organizations that have IRS 501(c)(3) tax exempt status and are located in and served the people of PSE's service territory in Washington State.

Deferral of Compensation. Nonemployee directors may choose to elect to defer all or a part of their cash fees under the Company's Deferred Compensation Plan for Nonemployee Directors. Nonemployee directors may allocate these deferrals into one or more "measurement funds," which include an interest crediting fund, an equity index fund and a bond index fund. Nonemployee directors are permitted to make changes in measurement fund allocations quarterly. None of the independent board members deferred any director fees during 2011.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SHAREHOLDER MATTERS

SECURITY OWNERSHIP OF DIRECTORS, EXECUTIVE OFFICERS AND CERTAIN BENEFICIAL OWNERS

The following tables show the number of shares of common stock beneficially owned as of December 31, 2011 by each person or group that we know owns more than 5.0% of Puget Energy's and PSE's common stock. No director, executive officer or executive officer named in the Summary Compensation Table in Item 11 of Part III of this report owns any of the outstanding shares of common stock of Puget Energy or PSE. Puget Equico LLC and its affiliates beneficially own 100.0% of the outstanding common stock of Puget Energy. Puget Energy holds 100.0% of the outstanding common stock of PSE. Percentage of beneficial ownership is based on 200 shares of Puget Energy common stock and 85,903,791 shares of Puget Sound Energy common stock outstanding as of December 31, 2011.

BENEFICIAL OWNERSHIP TABLE OF PUGET ENERGY AND PSE

	Number of Beneficially Owned Shares	
Name	Puget Energy	PSE
Puget Equico LLC and affiliates	200 [1, 2]	--
Puget Energy	--	85,903,791 [3]

1 *Information presented above and in this footnote is based on Amendment No. 2 to Schedule 13D/A filed on February 13, 2009 (the Schedule 13D) by Puget Equico LLC (Puget Equico), Puget Intermediate Holdings Inc. (Puget Intermediate), Puget Holdings LLC (Puget Holdings and together with Puget Intermediate, the Parent Entities), Macquarie Infrastructure Partners I (formerly MIP Padua Holdings GP) (MIP), Macquarie Infrastructure Partners II (formerly MIP Washington Holdings, L.P.) (MIP II), Macquarie FSS Infrastructure Trust (MFIT), Padua MG Holdings LLC (PMGH) Canada Pension Plan Investment Board (USRE II) Inc. (CPPIB), 6860141 Canada Inc. as trustee for British Columbia Investment Management Corporation (bcIMC), PIP2PX (Pad) Ltd. (PIP2PX) and PIP2GV (Pad) Ltd. (PIP2GV and together with MIP, MIP II, MFIT, PMGH, CPPIB, bcIMC and PIP2PX, the Investors). Puget Equico is a wholly-owned subsidiary of Puget Intermediate, Puget Intermediate is a wholly-owned subsidiary of Puget Holdings and the Investors are the direct or indirect owners of Puget Holdings. The Parent Entities and the Investors are the direct or indirect owners of Puget Equico. Although the Parent Entities and the Investors do not own any shares of Puget Energy directly, Puget Equico, the Parent Entities and the Investors may be deemed to be members of a "group," within the meaning of Section 13(d)(3) of the Securities Exchange Act of 1934, as amended. Accordingly, each such entity may be deemed to beneficially own the 200 shares of Puget Energy common stock owned by Puget Equico. Such shares of common stock constitute 100.0% of the issued and outstanding shares of common stock of Puget Energy. Under Section 13(d)(3) of the Exchange Act and based on the number of shares outstanding, Puget Equico, the Parent Entities and the Investors may be deemed to have shared power to vote and shared power to dispose of such shares of Puget Energy common stock that may be beneficially owned by Puget Equico. However, each of Puget Equico, the Parent Entities and the Investors expressly disclaims beneficial ownership of such shares of common stock other than those shares held directly by such entity. According to the Schedule 13D, as of February 13, 2009:*

- *The address of the principal office of Puget Holdings, Puget Intermediate and Puget Equico is the PSE Building, 10885 NE 4th Street, Bellevue, WA 98009.*
- *The address of the principal office of MIP and MIP II is 125 West 55th Street, Level 22, New York, NY 10019.*
- *The address of the principal office of MFIT is Level 11, 1 Martin Place, Sydney, Australia NSW 2000.*
- *The address of the principal office of PMGH is 125 West 55th Street, Level 22, New York, NY 10019.*
- *The address of the principal office of CPPIB is One Queen Street East, Suite 2600, P.O. Box 101, Toronto, Ontario, Canada M5C 2W5.*
- *The address of the principal office of bcIMC is Sawmill Point, Suite 301-2940 Jutland Road, Victoria, British Columbia, Canada V8T 5K6.*
- *The address of the principal office of PIP2PX and PIP2GV is 340 Terrace Building, 9515-107 Street, Edmonton, Alberta, Canada T5K 2C3.*

2 *Pursuant to that certain Pledge Agreement dated as of February 6, 2009, made by Puget Equico LLC to Barclays Bank PLC, as collateral agent and that certain Joinder Agreement dated December 6, 2010 by and among Barclays Bank PLC, as collateral agent, Barclays Bank PLC, as facility agent, Puget Energy, Puget Equico and Wells Fargo Bank, National Association as trustee, the outstanding stock of Puget Energy held by Puget Equico was pledged by Puget Equico to secure the obligations of Puget Energy under (a) the Credit Agreement dated as of May 16, 2008 among Puget Merger Sub Inc., as Borrower, Barclays Bank PLC, as Facility Agent, the other agents party thereto, and the lender party thereto (which agreement was subsequently assumed by Puget Energy) and (b) the senior secured notes issued on December 6, 2010.*

3 *Pursuant to that certain Borrower's Security Agreement dated as of February 6, 2009, and that certain Joinder Agreement dated December 6, 2010 by and among Barclays Bank PLC, as collateral agent, Barclays Bank PLC, as facility agent, Puget Energy, Puget Equico and Wells Fargo Bank, National Association as trustee, the outstanding stock of PSE held by Puget Energy was pledged by Puget Energy to secure its obligations under (a) the Credit Agreement dated as of May 16, 2008, as amended, among Puget Merger Sub Inc,. as Borrower, Barclays Bank PLC, as Facility Agent, the other agents party thereto, and the lender party thereto (which agreement was subsequently assumed by Puget Energy) and (b) the senior secured notes issued on December 6, 2010.*

EQUITY COMPENSATION PLAN INFORMATION

In connection with the merger of Puget Energy with Puget Holdings, which was completed on February 6, 2009, all compensation plans under which equity securities were authorized for issuance have been terminated, except the LTI Plan. Following the merger, only non-equity awards that can be settled solely in cash are made under the LTI Plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

TRANSACTIONS WITH RELATED PERSONS

Our Boards of Directors have adopted a written policy for the review and approval or ratification of related person transactions. Under the policy, our directors and executive officers are expected to disclose to our Chief Compliance Officer the material facts of any transaction that could be considered a related person transaction promptly upon gaining knowledge of the transaction. A related person transaction is generally defined as any transaction required to be disclosed under Item 404(a) of Regulation S-K, the SEC's related person transaction disclosure rule.

Any transaction reported to the Chief Compliance Officer will be reviewed according to the following procedures:

- If the Chief Compliance Officer determines that disclosure of the transaction is not required under the SEC's related person transaction disclosure rule, the transaction will be deemed approved and will be reported to the Audit Committee.
- If disclosure is required, the Chief Compliance Officer will submit the transaction to the Chair of the Audit Committee who will review and, if authorized, will determine whether to approve or ratify the transaction. The Chair is authorized to approve or ratify any related person transaction involving an aggregate amount of less than $1.0 million or when it would be impracticable to wait for the next Audit Committee meeting to review the transaction.
- If the transaction is outside the Chair's authority, the Chair will submit the transaction to the Audit Committee for review and approval or ratification.

When determining whether to approve or ratify a related person transaction, the Chair of the Audit Committee or the Audit Committee, as applicable, will review relevant facts regarding the related person transaction, including:

- The extent of the related person's interest in the transaction;
- Whether the terms are comparable to those generally available in arms' length transactions; and
- Whether the related person transaction is consistent with the best interests of the Company.

If any related person transaction is not approved or ratified, the Committee may take such action as it may deem necessary or desirable in the best interests of the Company and its shareholders.

Kimberly Harris, who serves as the President and Chief Executive Officer, as well as a director of Puget Energy and PSE, is married to Kyle Branum, a principal at the law firm Riddell Williams P.S. since 2008. Riddell Williams or its predecessor firms have been one of PSE's primary law firms for nearly 50 years. In 2011, Riddell Williams was paid $1.63 million for legal services provided to PSE. Mr. Branum is among the lawyers at Riddell Williams who provide legal services to PSE. This work was performed under the direct supervision of the office of the general counsel and the compensation arrangements were comparable to other regional law firms providing legal services to PSE.

Puget Energy is party to interest rate swap agreements, negotiated under the International Swaps and Derivatives Association, Inc. ("ISDA agreements"), with various parties, including Macquarie Bank Limited. Affiliates of Macquarie Bank Limited indirectly own an equity interest in PSE. The ISDA agreements were the product of arms' length negotiations between Puget Energy and the various counterparties, including Macquarie Bank Limited, and contain terms and conditions similar to those of other master swap agreements with unrelated third parties.

BOARD OF DIRECTORS AND CORPORATE GOVERNANCE

INDEPENDENCE OF THE BOARD

The Boards of Puget Energy and PSE have reviewed the relationships between Puget Energy and PSE (and their respective subsidiaries) and each of their respective directors. Based on this review, the Boards have determined that of the members constituting the Boards, William Ayer (member of the Boards of both Puget Energy and PSE), Mary McWilliams (member of the Boards of both Puget Energy and PSE), Melanie Dressel (member of the Boards of both Puget Energy and PSE), and Herbert Simon (member of the Board of PSE) are independent under the New York Stock Exchange (NYSE) corporate governance listing standards and also meet the definition of an "Independent Director" under the Company's Amended and Restated Bylaws. Under the Amended and Restated Bylaws of Puget Energy and PSE, an Independent Director is a director who: (a) shall not be a member of Puget Holdings (referred to as a Holdings Member) or an affiliate of any Holdings Member (including by way of being a member, stockholder, director, manager, partner, officer or employee of any such member), (b) shall not be an officer or employee of PSE, (c) shall be a resident of the state of Washington, and (d) if and to the extent required with respect to any specific director, shall meet such other qualifications as may be required by any applicable regulatory authority for an independent director or manager. The Company's definition of "Independent Director" is available in the Corporate Governance Guidelines at www.pugetenergy.com.

In making these independence determinations, the Boards have established a categorical standard that a director's independence is not impaired solely as a result of the director, or a company for which the director or an immediate family member of the director serves as an executive officer, making payments to PSE for power or natural gas provided by PSE at rates fixed in conformity with law or governmental authority, unless such payments would automatically disqualify the director under the NYSE's corporate governance listing standards. The Board has also established a categorical standard that a director's independence is not impaired if a director is a director, employee or executive officer of another company that makes payments to or receives payments from Puget Energy, PSE or any of their affiliates, for property or services in an amount which is less than the greater of $1.0 million or one percent of such other company's consolidated gross revenue, determined for the most recent fiscal year. These categorical standards will not apply, however, to the extent that Puget Energy or PSE would be required to disclose an arrangement as a related person transaction pursuant to Item 404 of Regulation S-K.

The Boards considered all relationships between its directors and Puget Energy and PSE (and their respective subsidiaries), including some that are not required to be disclosed in this report as related-person transactions. Messrs. Ayer and Simon, Ms. McWilliams and Ms. Dressel serve as directors or officers of, or otherwise have a financial interest in, entities that make payments to PSE for energy services provided to those entities at tariff rates established by the Washington Utilities and Transportation Commission. These transactions fall within the first categorical independence standard described above. In addition, PSE has entered into transactions with entities for whom Mr. Simon serves as a director or officer, or in which he otherwise has a financial interest, that involve amounts that are less than the greater of $1.0 million or 1% of those entities' consolidated gross revenue. These transactions fall within the second categorical standard described above. Because these relationships either fall within the Board's categorical independence standards or involve an amount that is not material to the Company or the other entity, the Boards have concluded that none of these relationships impair the independence of the applicable directors.

EXECUTIVE SESSIONS

Non-management directors meet in executive session on a regular basis, generally on the same date as each scheduled Board meeting. Mr. Ayer, who is not a member of management, presides over the executive sessions. Interested parties may communicate with the non-management directors of the Board through the procedures described in Item 10 of Part III of this annual report under the section "Communications with the Board."

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The aggregate fees billed by PricewaterhouseCoopers LLP, the Company's independent registered public accounting firm, for the years ended December 31 were as follows:

	2011		2010	
(DOLLARS IN THOUSANDS)	PUGET ENERGY	PSE	PUGET ENERGY	PSE
Audit fees [1]	$ 1,632	$ 1,519	$ 1,558	$ 1,453
Audit related fees [2]	387	325	332	264
Tax fees [3]	--	27	--	72
Total	$ 2,019	$ 1,871	$ 1,890	$ 1,789

1 *For professional services rendered for the audit of Puget Energy's and PSE's annual financial statements and reviews of financial statements included in the Company's Forms 10-Q. The 2011 fees are estimated and include an aggregate amount of $0.8 million billed to Puget Energy and $0.9 million to PSE through December 2011.*
2 *Consists of employee benefit plan audits, work performed in connection with registration statements and other regulatory audits.*
3 *Consists of tax consulting and tax return reviews.*

The Audit Committee of the Company has adopted policies for the pre-approval of all audit and non-audit services provided by the Company's independent registered public accounting firm. The policies are designed to ensure that the provision of these services does not impair the firm's independence. Under the policies, unless a type of service to be provided by the independent registered public accounting firm has received general pre-approval, it will require specific pre-approval by an Audit Committee. In addition, any proposed services exceeding pre-approved cost levels will require specific pre-approval by an Audit Committee.

The annual audit services engagement terms and fees, as well as any changes in terms, conditions and fees relating to the engagement, are subject to specific pre-approval by the Audit Committee. In addition, on an annual basis, the Audit Committee grants general pre-approval for specific categories of audit, audit-related, tax and other services, within specified fee levels, that may be provided by the independent registered public accounting firm. With respect to each proposed pre-approved service, the independent registered public accounting firm is required to provide detailed back-up documentation to the Audit Committee regarding the specific services to be provided. Under the policies, the Audit Committee may delegate pre-approval authority to one or more of their members. The member or members to whom such authority is delegated shall report any pre-approval decision to the Audit Committee at its next scheduled meeting. The Audit Committee does not delegate responsibilities to pre-approve services performed by the independent registered public accounting firm to management.

For 2011 and 2010, all audit and non-audit services were pre-approved.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

a) Documents filed as part of this report:
   1) *Financial Statements.* See index on page 65.
   2) *Financial Statement Schedules*. Financial Statement Schedules of the Company located on page 136, as required for the years ended December 31, 2011, 2010 and 2009, consist of the following:

      I. Condensed Financial Information of Puget
      II. Valuation of Qualifying Accounts

   3) Exhibits - see index on page 177.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUGET ENERGY, INC.	PUGET SOUND ENERGY, INC.
/s/ Kimberly J. Harris	/s/ Kimberly J. Harris
Kimberly J. Harris	Kimberly J. Harris
President and Chief Executive Officer	President and Chief Executive Officer
Date: March 5, 2012	Date: March 5, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of each registrant and in the capacities and on the dates indicated.

SIGNATURE	TITLE (Puget Energy and PSE unless otherwise noted)	DATE
/s/ Kimberly J. Harris (Kimberly J. Harris)	President and Chief Executive Officer	March 5, 2012
/s/ Daniel A. Doyle (Daniel A. Doyle)	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	
/s/ William S. Ayer (William S. Ayer)	Chairman and Director	
/s/ Andrew Chapman (Andrew Chapman)	Director	
/s/ Melanie Dressel (Melanie Dressel)	Director	
/s/ Benjamin Hawkins (Benjamin Hawkins)	Director	
/s/ Alan W. James (Alan W. James)	Director	
/s/ Alan Kadic (Alan Kadic)	Director	
/s/ Christopher J. Leslie (Christopher J. Leslie)	Director	

/s/ Mary O. McWilliams (Mary O. McWilliams)	Director
/s/ Christopher Trumpy (Christopher Trumpy)	Director
/s/ Mark Wiseman (Mark Wiseman)	Director
/s/ Herbert B. Simon (Herbert B. Simon)	Director of PSE only

EXHIBIT INDEX

Certain of the following exhibits are filed herewith. Certain other of the following exhibits have heretofore been filed with the Securities and Exchange Commission and are incorporated herein by reference.

2.1	Agreement and Plan of Merger, dated October 25, 2007, by and among Puget Energy, Inc., Padua Holdings LLC, Padua Intermediate Holdings Inc. and Padua Merger Sub Inc. (incorporated herein by reference to Exhibit 2.1 to Puget Energy's Current Report on Form 8-K, dated October 25, 2007, Commission File No. 1-16305).
3(i).1	Amended Articles of Incorporation of Puget Energy (incorporated herein by reference to Exhibit 3.1 to Puget Energy's Current Report on Form 8-K, dated February 6, 2009, Commission File No. 1-16305).
3(i).2	Amended and Restated Articles of Incorporation of Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 3.2 to Puget Sound Energy's Current Report on Form 8-K, dated February 6, 2009, Commission File No. 1-4393).
3(ii).1	Amended and Restated Bylaws of Puget Energy dated February 6, 2009 (incorporated herein by reference to Exhibit 3.3 to Puget Energy's Current Report on Form 8-K, Commission File No. 1-16305).
3(ii).2	Amended and Restated Bylaws of Puget Sound Energy, Inc. dated February 6, 2009 (incorporated herein by reference to Exhibit 3.4 to Puget Sound Energy's Current Report on Form 8-K, Commission File No. 1-4393).
4.1	Indenture between Puget Sound Energy, Inc. and U.S. Bank National Association (as successor to State Street Bank and Trust Company) defining the rights of the holders of Puget Sound Energy's senior notes (incorporated herein by reference to Exhibit 4-a to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 30, 1998, Commission File No. 1-4393).
4.2	First, Second, Third and Fourth Supplemental Indentures defining the rights of the holders of Puget Sound Energy's senior notes (incorporated herein by reference to Exhibit 4-b to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 30, 1998, Commission File No. 1-4393; Exhibit 4.26 to Puget Sound Energy's Current Report on Form 8-K, dated March 4, 1999, Commission File No. 1-4393; Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated November 2, 2000, Commission File No. 1-4393; and Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated May 28, 2003, Commission File No. 1-4393).
4.3	Fortieth through Sixtieth Supplemental Indentures defining the rights of the holders of Puget Sound Energy's Electric Utility First Mortgage Bond (incorporated herein by reference to Exhibits 4.3 through and including 4.23 to Puget Sound Energy's Registration Statement on Form S-3ASR, filed March 13, 2009, Registration No. 333-157960).
4.4	Sixty-first through Eighty-seventh Supplemental Indentures defining the rights of the holders of Puget Sound Energy's Electric Utility First Mortgage Bonds (incorporated herein by reference to Exhibit (4)-j-1 to Registration No. 2-72061; Exhibit (4)-a to Registration No. 2-91516; Exhibit (4)-b to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 1985, Commission File No. 1-4393; Exhibits (4)(a) and (4)(b) to Puget Sound Energy's Current Report on Form 8-K, dated April 22, 1986, Commission File No. 1-4393; Exhibit (4)(b) to Puget Sound Energy's Current Report on Form 8-K, dated September 5, 1986, Commission File No. 1-4393; Exhibit (4)-b to Puget Sound Energy's Report on Form 10-Q for the quarter ended September 30, 1986, Commission File No. 1-4393; Exhibit (4)-c to Registration No. 33-18506; Exhibit (4)-b to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 1989, Commission File No. 1-4393; Exhibit (4)-b to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393; Exhibits (4)-d and (4)-e to Registration No. 33-45916; Exhibit (4)-c to Registration No. 33-50788; Exhibit (4)-a to Registration No. 33-53056; Exhibit 4.3 to Registration No. 33-63278; Exhibit 4-c to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 20, 1998, Commission File No. 1-4393; Exhibit 4.27 to Puget Sound Energy's Current Report on Form 8-K, dated March 4, 1999, Commission File No. 1-4393; Exhibit 4.2 to Puget Sound Energy's Current Report on Form 8-K, dated November 2, 2000, Commission File No. 1-4393; Exhibit 4.2 to Puget Sound Energy's Current Report on Form 8-K, dated May 28, 2003, Commission File No. 1-4393; Exhibit 4.28 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2004, Commission File No. 1-4393; Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated May 23, 2005, Commission File No. 1-4393; Exhibit 4.30 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2005, Commission File No. 1-4393); Exhibit 4.4 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009, Registration No. 333-132497-01; Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated September 13, 2006, Commission File No. 1-4393; Exhibit 4.1 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2007, Commission File No. 1-4393; and Exhibit 4.5 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009, Registration No. 333-132497-01); Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated September 8, 2009, Commission File No. 1-4393.

4.5 Indenture of First Mortgage, dated as of April 1, 1957, defining the rights of the holders of Puget Sound Energy's Gas Utility First Mortgage Bonds (incorporated herein by reference to Puget Sound Energy's Registration Statement on Form S-3ASR, filed March 13, 2009, Registration No. 333-157960).

4.6 First, Sixth, Seventh and Seventeenth Supplemental Indenture to the Gas Utility First Mortgage, dated as of October 1, 1959, August 1, 1966, February 1, 1967, June 1, 1977 and August 9, 1978, respectively (incorporated herein by reference to Exhibits 4.26 through and including 4.30 to Puget Sound Energy's Registration Statement on Form S-3ASR, filed March 13, 2009, Registration No. 333-157960).

4.7 Twenty-second Supplemental Indenture to the Gas Utility First Mortgage, dated as of July 15, 1986 (incorporated herein by reference to Exhibit 4-B.20 to Washington Natural Gas Company's Report on Form 10-K for the fiscal year ended September 30, 1986, Commission File No. 0-951).

4.8 Twenty-seventh Supplemental Indenture to the Gas Utility First Mortgage, dated as of September 1, 1990 (incorporated herein by reference to Exhibit 4.12 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009, Registration No. 333-132497-01).

4.9 Twenty-eighth through Thirty-sixth Supplemental Indentures to the Gas Utility First Mortgage (incorporated herein by reference to Exhibit 4-A to Washington Natural Gas Company's Report on Form 10-Q for the quarter ended March 31, 1993, Commission File No. 0-951; Exhibit 4-A to Washington Natural Gas Company's Registration Statement on Form S-3, Registration No. 33-49599; Exhibit 4-A to Washington Natural Gas Company's Registration Statement on Form S-3, Registration No. 33-61859; Exhibit 4.30 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-4393; Exhibits 4.22 and 4.23 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2005, Commission File No. 1-4393; Exhibits 4.22 and 4.23 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2007, Commission File No. 1-4393; and Exhibit 4.14 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009, Registration No. 333-132497-01).

4.10 Unsecured Debt Indenture, dated as of May 18, 2001, between Puget Sound Energy, Inc. and The Bank of New York Trust Company, N.A. (as successor to Bank One Trust Company, N.A.) defining the rights of the holders of Puget Sound Energy's unsecured debentures (incorporated herein by reference to Exhibit 4.3 to Puget Sound Energy's Current Report on Form 8-K, dated May 18, 2001, Commission File No. 1-4393).

4.11 Second Supplemental Indenture to the Unsecured Debt Indenture, dated June 1, 2007, between Puget Sound Energy, Inc. and The Bank of New York Trust Company, N.A. defining the rights of Puget Sound Energy's Series A Enhanced Junior Subordinated Notes due June 1, 2067 (incorporated herein by reference to Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated May 30, 2007, Commission File No. 1-4393).

4.12 Form of Replacement Capital Covenant of Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 4.2 to Puget Sound Energy's Current Report on Form 8-K, dated May 30, 2007, Commission File No. 1-4393).

4.13 Pledge Agreement dated March 11, 2003 between Puget Sound Energy, Inc. and Wells Fargo Bank Northwest, National Association, as Trustee (incorporated herein by reference to Exhibit 4.24 to Post-Effective Amendment No. 1 to Puget Sound Energy's Registration Statement on Form S-3, filed July 11, 2003, Registration No. 333-82940-02).

4.14 Loan Agreement dated as of March 1, 2003, between the City of Forsyth, Rosebud County, Montana and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 4.25 to Post-Effective Amendment No. 1 to Puget Sound Energy's Registration Statement on Form S-3, filed July 11, 2003, Registration No. 333-82490).

4.15 Indenture and First Supplemental Indenture between Wells Fargo Bank, National Association and Puget Energy, Inc. dated as of December 6, 2010 (incorporated by reference to Exhibits 4.1 and 4.2 to Puget Energy's Current Report on Form 8-K, filed December 7, 2010, Commission File No. 1-16305).

4.16 Second Supplemental Indenture to the Indenture dated December 6, 2010 between Puget Energy, Inc. and Wells Fargo Bank, National Association defining the rights of Puget Energy's Senior Secured Notes due September 1, 2021 (incorporated herein by reference to Exhibit 4.1 to Puget Energy's Current Report on Form 8-K, filed June 6, 2011, Commission File No. 1-16305).

10.1 First Amendment dated as of October 4, 1961 to Power Sales Contract between Public Utility District No. 1 of Chelan County, Washington and Puget Sound Energy, Inc., relating to the Rocky Reach Project (incorporated herein by reference to Exhibit 10.1 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.2 First Amendment dated February 9, 1965 to Power Sales Contract between Public Utility District No. 1 of Douglas County, Washington and Puget Sound Energy, Inc., relating to the Wells Development (incorporated herein by reference to Exhibit 10.2 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.3 Contract dated November 14, 1957 between Public Utility District No. 1 of Chelan County, Washington and Puget Sound Energy, Inc., relating to the Rocky Reach Project (incorporated herein by reference to Exhibit

10.3 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.4 Power Sales Contract dated as of November 14, 1957 between Public Utility District No. 1 of Chelan County, Washington and Puget Sound Energy, Inc., relating to the Rocky Reach Project (incorporated herein by reference to Exhibit 10.4 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.5 Power Sales Contract dated May 21, 1956 between Public Utility District No. 2 of Grant County, Washington and Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 10.5 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.6 First Amendment to Power Sales Contract dated as of August 5, 1958 between Puget Sound Energy, Inc. and Public Utility District No. 2 of Grant County, Washington, relating to the Priest Rapids Development (incorporated herein by reference to Exhibit 10.6 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.7 Power Sales Contract dated June 22, 1959 between Public Utility District No. 2 of Grant County, Washington and Puget Sound Energy, Inc., relating to the Wanapum Development (incorporated herein by reference to Exhibit 10.7 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.8 Agreement to Amend Power Sales Contracts dated July 30, 1963 between Public Utility District No. 2 of Grant County, Washington and Puget Sound Energy, Inc., relating to the Wanapum Development (incorporated herein by reference to Exhibit 10.8 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.9 Power Sales Contract executed as of September 18, 1963 between Public Utility District No. 1 of Douglas County, Washington and Puget Sound Energy, Inc., relating to the Wells Development (incorporated herein by reference to Exhibit 10.9 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.10 Construction and Ownership Agreement dated as of July 30, 1971 between The Montana Power Company and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 10.10 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.11 Operation and Maintenance Agreement dated as of July 30, 1971 between The Montana Power Company and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 10.11 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.12 Contract dated June 19, 1974 between Puget Sound Energy, Inc. and P.U.D. No. 1 of Chelan County (incorporated herein by reference to Exhibit 10.12 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

10.13 Transmission Agreement dated April 17, 1981 between the Bonneville Power Administration and Puget Sound Energy, Inc. (Colstrip Project) (incorporated herein by reference to Exhibit (10)-55 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.14 Transmission Agreement dated April 17, 1981 between the Bonneville Power Administration and Montana Intertie Users (Colstrip Project) (incorporated herein by reference to Exhibit (10)-56 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.15 Ownership and Operation Agreement dated as of May 6, 1981 between Puget Sound Energy, Inc. and other Owners of the Colstrip Project (Colstrip 3 and 4) (incorporated herein by reference to Exhibit (10)-57 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.16 Colstrip Project Transmission Agreement dated as of May 6, 1981 between Puget Sound Energy, Inc. and Owners of the Colstrip Project (incorporated herein by reference to Exhibit (10)-58 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.17 Common Facilities Agreement dated as of May 6, 1981 between Puget Sound Energy, Inc. and Owners of Colstrip 1 and 2, and 3 and 4 (incorporated herein by reference to Exhibit (10)-59 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.18 Amendment dated as of June 1, 1968, to Power Sales Contract between Public Utility District No. 1 of Chelan County, Washington and Puget Sound Energy, Inc. (Rocky Reach Project) (incorporated herein by reference to Exhibit (10)-66 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.19 Transmission Agreement dated as of December 30, 1987 between the Bonneville Power Administration and Puget Sound Energy, Inc. (Rock Island Project) (incorporated herein by reference to Exhibit (10)-74 to Report on Form 10-K for the fiscal year ended December 31, 1988, Commission File No. 1-4393).

10.20 Amendment No. 1 to the Colstrip Project Transmission Agreement dated as of February 14, 1990 among The Montana Power Company, The Washington Water Power Company (Avista), Portland General Electric Company, PacifiCorp and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-91 to Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393).

10.21 Agreement for Firm Power Purchase (Thermal Project) dated December 27, 1990 among March Point Cogeneration Company, a California general partnership comprising San Juan Energy Company, a California corporation; Texas-Anacortes Cogeneration Company, a Delaware corporation; and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-4 to Report on Form 10-Q for the quarter ended March 31, 1991, Commission File No. 1-4393).

10.22 Agreement for Firm Power Purchase dated March 20, 1991 between Tenaska Washington, Inc., a Delaware corporation, and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-1 to Report on Form 10-Q for the quarter ended June 30, 1991, Commission File No. 1-4393).

10.23 Amendment of Seasonal Exchange Agreement, dated December 4, 1991 between Pacific Gas and Electric Company and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-107 to Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-4393).

10.24 Capacity and Energy Exchange Agreement, dated as of October 4, 1991 between Pacific Gas and Electric Company and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-108 to Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-4393).

10.25 General Transmission Agreement dated as of December 1, 1994 between the Bonneville Power Administration and Puget Sound Energy, Inc. (BPA Contract No. DE-MS79-94BP93947) (incorporated herein by reference to Exhibit 10.115 to Report on Form 10-K for the fiscal year ended December 31, 1994, Commission File No. 1-4393).

10.26 PNW AC Intertie Capacity Ownership Agreement dated as of October 11, 1994 between the Bonneville Power Administration and Puget Sound Energy, Inc. (BPA Contract No. DE-MS79-94BP94521) (incorporated herein by reference to Exhibit 10.116 to Report on Form 10-K for the fiscal year ended December 31, 1994, Commission File No. 1-4393).

10.27 Amendment to Gas Transportation Service Contract dated July 31, 1991 between Washington Natural Gas Company and Northwest Pipeline Corporation (incorporated herein by reference to Exhibit 10-E.2 to Washington Natural Gas Company’s Form 10-K for the fiscal year ended September 30, 1995, Commission File No. 1-11271).

10.28 Firm Transportation Service Agreement dated January 12, 1994 between Northwest Pipeline Corporation and Washington Natural Gas Company for firm transportation service from Jackson Prairie (incorporated herein by reference to Exhibit 10-P to Washington Natural Gas Company’s Form 10-K for the fiscal year ended September 30, 1994, Commission File No. 1-11271).

10.29 Product Sales Contract dated December 13, 2001 and Amendment No. 1 thereto, between Public Utility District No. 2 of Grant County, Washington, and Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 10-1 to Puget Sound Energy’s Report on Form 10-Q for the quarter ended June 30, 2002, File No. 1-4393).

10.30 Reasonable Portion Power Sales Contract dated December 13, 2001 and Amendment No. 1 thereto, between Public Utility District No. 2 of Grant County, Washington, and Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 10-2 to Puget Sound Energy’s Report on Form 10-Q for the quarter ended June 30, 2002, Commission File No. 1-4393).

10.31 Additional Products Sales Agreement dated December 13, 2001, and Amendment No. 1 thereto, between Public Utility District No. 2 of Grant County, Washington, and Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 10.3 to Puget Sound Energy’s Report on Form 10-Q for the quarter ended June 30, 2002, Commission File No. 1-4393).

10.32 Credit Agreement dated as of February 10, 2012 among Puget Energy, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, the other agents party thereto, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to Puget Energy’s and Puget Sound Energy’s Report on Form 8-K dated February 16, 2012, Commission File Nos. 1-16305 and 1-4393).

10.33 Credit Agreement dated as of February 6, 2009 among Puget Sound Energy, Inc., as Borrower, Barclays Bank PLC, as Facility Agent, the other agents party thereto, and the lenders party thereto (incorporated herein by reference to Exhibit 10.2 to Puget Energy’s and Puget Sound Energy’s Report on Form 10-Q for the quarter ended September 30, 2009, Commission File Nos. 1-16305 and 1-4393).

10.34 Amendment dated May 10, 2010 to Credit Agreement (dated February 6, 2009) among Puget Sound Energy, Inc. as Borrower, Barclays Bank PLC, as Facility Agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to Puget Energy’s and Puget Sound Energy’s Report on Form 10-Q for the quarter ended June 30, 2010, Commission File Nos. 1-16305 and 1-4393).

** 10.35 Employment agreement with S. P. Reynolds, Chief Executive Officer and President, dated January 1, 2002 (incorporated herein by reference to Exhibit 10.104 to the Report on Form 10-K for the fiscal year ended December 31, 2001, Commission File Nos. 1-16305 and 1-4393).

** 10.36 First Amendment effective May 12, 2005 to employment agreement with S.P. Reynolds, Chief Executive Officer and President, dated as of January 1, 2002 (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K, dated May 12, 2005, Commission File Nos. 1-16305 and 1-4393).

** 10.37	Second Amendment dated February 9, 2006 to employment agreement with S. P. Reynolds, Chief Executive Officer and President, dated as of January 1, 2002 and amended as of May 10, 2005 (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K, dated February 14, 2006, Commission File Nos. 1-16305 and 1-4393).
** 10.38	Third Amendment dated February 28, 2008 to employment agreement with S.P. Reynolds, Chief Executive Officer and President, dated as of January 1, 2002 and amended as of February 9, 2006 (incorporated herein by reference to Exhibit 10.44 to Puget Energy's Report on Form 10-K for the fiscal year ended December 31, 2007, Commission File No. 1-16305 and 1-4393).
** 10.39	Form of Executive Employment Agreement with Executive Officers (incorporated herein by reference to Exhibit 10.1 to Puget Sound Energy's Current Report on Form 8-K, dated April 3, 2009, Commission File No. 1-4393).
** 10.40	Waiver of rights to certain payments and other benefits, executed by Stephen P. Reynolds, Chief Executive Officer and President, dated February 25, 2010.
** 10.41	Puget Sound Energy, Inc. Amended and Restated Supplemental Executive Retirement Plan effective January 1, 2009 (incorporated herein by reference to Exhibit 10.39 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
** 10.42	Puget Sound Energy, Inc. Amended and Restated Deferred Compensation Plan for Key Employees effective January 1, 2009 (incorporated herein by reference to Exhibit 10.40 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
** 10.43	Puget Sound Energy, Inc. Amended and Restated Deferred Compensation Plan for Nonemployee Directors effective January 1, 2009 (incorporated herein by reference to Exhibit 10.41 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
** 10.44	Summary of Director Compensation (incorporated herein by reference to Exhibit 10.51 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2006, Commission File No. 1-16305 and 1-4393).
** 10.45	Form of Amended and Restated Change of Control Agreement between Puget Sound Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K, dated February 14, 2006, Commission File Nos. 1-4393).
** 10.46	Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective October 1, 2000, as amended (incorporated herein by reference to Exhibit 10.45 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
** 10.47	Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective January 1, 2002, as amended (incorporated herein by reference to Exhibit 10.46 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
** 10.48	Puget Sound Energy, Inc. Supplemental Disability Plan for Executive Employees, effective October 1, 2000, as amended (incorporated herein by reference to Exhibit 10.47 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
** 10.49	Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective November 1, 2007, as amended (incorporated herein by reference to Exhibit 10.48 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
** 10.50	Puget Energy, Inc. Amended and Restated 2005 Long-Term Incentive Plan, effective March 4, 2011 (incorporated herein by reference to Exhibit 10.52 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2010, Commission File No. 1-16305 and 1-4393).
* 12.1	Statement setting forth computation of ratios of earnings to fixed charges of Puget Energy, Inc. (2007 through 2011).
* 12.2	Statement setting forth computation of ratios of earnings to fixed charges of Puget Sound Energy, Inc. (2007 through 2011).
* 21.1	Subsidiaries of Puget Energy, Inc.
* 21.2	Subsidiaries of Puget Sound Energy, Inc.
* 23.1	Consent of PricewaterhouseCoopers LLP.
* 31.1	Certification of Puget Energy, Inc. - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Kimberly J. Harris.
* 31.2	Certification of Puget Energy, Inc. - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Daniel A. Doyle.

*	31.3	Certification of Puget Sound Energy, Inc. - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Kimberly J. Harris.
*	31.4	Certification of Puget Sound Energy, Inc. – Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Daniel A. Doyle.
*	32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Kimberly J. Harris.
*	32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Daniel A. Doyle.
***	101	Financial statements from the annual report on Form 10-K of Puget Energy, Inc. and Puget Sound Energy, Inc. for the fiscal year ended December 31, 2011, filed on March 5, 2012, formatted in XBRL: (i) the Consolidated Statement of Income (Unaudited), (ii) the Consolidated Statements of Comprehensive Income (Unaudited), (iii) the Consolidated Balance Sheets (Unaudited), (iii) the Consolidated Statements of Cash Flows (Unaudited), and (iv) the Notes to Consolidated Financial Statements tagged as blocks of text (submitted electronically herewith).

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* *Filed herewith.*

** *Management contract, compensating plan or arrangement.*

*** *In accordance with Rule 406T of Regulation S-T, the XBRL information in Exhibit 101 to this annual report on Form 10-K shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.*

Attachment 32.1

Schedule 1

SELECTED INDICATORS OF ECONOMIC ACTIVITY
(1989 = 100)

		Canada							United States						
		Gross Domestic Product					After-Tax Profits		Gross Domestic Product					After-Tax Profits	
		Constant Dollars	Current Dollars	Industrial Production	GDP Deflator Index	Consumer Price Index	Billions of Dollars	As Percent of GDP	Constant Dollars	Current Dollars	Industrial Production	Implicit Price Index	Consumer Price Index	Billions of Dollars	As Percent of GDP
Year		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1989		100.0	100.0	100.0	100.0	100.0	41	6.3%	100.0	100.0	100.0	100.0	100.0	244	4.5%
1990		100.2	103.4	97.2	103.2	104.8	28	4.1%	101.9	105.8	101.0	103.9	105.4	266	4.6%
1991		98.1	104.2	93.5	106.2	110.7	18	2.6%	101.6	109.3	99.4	107.5	109.8	287	4.8%
1992		99.0	106.5	94.5	107.6	112.3	18	2.6%	105.1	115.7	102.2	110.1	113.2	326	5.1%
1993		101.3	110.6	98.8	109.2	114.4	25	3.4%	108.1	121.6	105.6	112.5	116.5	348	5.2%
1994		106.1	117.2	105.1	110.4	114.6	46	6.0%	112.5	129.2	111.1	114.9	119.5	406	5.7%
1995		109.1	122.7	109.9	112.9	117.1	54	6.7%	115.3	135.3	116.4	117.3	122.9	466	6.3%
1996		110.9	126.8	111.8	114.7	118.9	54	6.5%	119.6	143.0	121.6	119.5	126.5	509	6.5%
1997		115.6	133.5	118.0	116.1	120.8	56	6.3%	125.0	152.0	130.4	121.6	129.5	556	6.7%
1998		120.3	139.2	122.2	115.6	122.0	55	6.0%	130.4	160.4	137.9	123.0	131.5	475	5.4%
1999		127.0	149.4	129.8	117.6	124.2	71	7.3%	136.7	170.6	143.9	124.8	134.4	522	5.6%
2000		133.6	163.5	139.6	122.5	127.5	88	8.1%	142.4	181.5	149.6	127.5	138.9	507	5.1%
2001		136.0	168.5	134.6	123.9	130.8	91	8.2%	143.9	187.6	144.5	130.4	142.8	509	5.0%
2002		140.0	175.3	137.5	125.2	133.7	99	8.6%	146.5	194.1	144.7	132.5	145.1	573	5.4%
2003		142.6	184.4	137.7	129.4	137.4	105	8.6%	150.2	203.2	146.5	135.3	148.4	570	5.9%
2004		147.0	196.3	139.8	133.5	139.9	122	9.4%	155.4	216.2	149.9	139.1	152.3	923	7.8%
2005		151.5	208.9	142.1	137.9	143.0	138	10.0%	160.2	230.3	154.8	143.7	157.5	1,228	9.7%
2006		155.8	220.5	142.1	141.6	145.9	140	9.7%	164.5	244.0	158.2	148.4	162.6	1,349	10.1%
2007		159.2	232.6	141.4	146.1	149.0	146	9.5%	167.6	255.9	162.1	152.7	167.2	1,293	9.2%
2008		160.3	243.8	137.1	152.1	152.6	168	10.5%	167.0	260.7	156.4	156.1	173.6	1,051	7.3%
2009		155.8	232.5	124.1	149.2	153.0	96	6.3%	161.2	254.3	138.5	157.7	173.0	1,183	8.5%
2010		160.9	247.0	130.2	153.6	155.7	126	7.7%	166.1	265.0	146.0	159.5	175.9	1,408	9.7%
2011		164.8	261.3	134.7	158.6	160.3	153	8.9%	169.0	275.3	152.0	162.9	181.4	1,480	9.8%
2007	Q1	157.6	227.6	142.4	144.4	147.4	139	9.3%	165.7	251.0	160.5	151.5	164.3	1,264	9.2%
	Q2	158.9	232.5	142.3	146.3	149.6	144	9.4%	167.2	255.0	162.3	152.5	167.5	1,316	9.4%
	Q3	159.7	233.4	141.4	146.2	149.6	148	9.6%	168.4	257.7	162.7	153.0	167.9	1,284	9.1%
	Q4	160.5	236.7	139.7	147.4	149.5	152	9.8%	169.1	260.0	163.0	153.7	169.1	1,308	9.2%
2008	Q1	160.3	240.3	138.2	150.0	150.0	163	10.3%	168.4	260.4	162.5	154.6	171.0	1,188	8.3%
	Q2	160.5	246.5	137.6	153.6	153.1	181	11.2%	168.9	263.0	160.1	155.7	174.8	1,208	8.4%
	Q3	160.9	249.3	138.0	155.0	154.7	186	11.4%	167.4	262.6	154.8	156.9	176.8	1,163	8.1%
	Q4	159.4	239.0	134.4	150.0	152.4	142	9.0%	163.5	256.9	148.2	157.1	171.8	644	4.6%
2009	Q1	156.1	230.7	128.0	147.8	151.9	105	6.9%	160.7	253.4	140.4	157.7	171.0	1,000	7.2%
	Q2	154.7	229.3	122.6	148.3	153.2	93	6.2%	160.4	252.7	136.2	157.5	172.8	1,099	7.9%
	Q3	155.3	232.0	121.6	149.5	153.4	91	6.0%	161.1	253.9	137.9	157.6	174.0	1,244	8.9%
	Q4	157.2	237.8	124.1	151.3	153.6	93	6.0%	162.6	257.0	139.8	158.0	174.3	1,390	9.9%
2010	Q1	159.4	243.4	127.3	152.7	154.4	109	6.8%	164.2	260.4	142.4	158.6	175.0	1,416	9.9%
	Q2	160.3	244.8	130.1	152.8	155.3	114	7.1%	165.7	263.9	145.4	159.2	175.8	1,466	10.1%
	Q3	161.3	247.1	131.0	153.3	156.2	133	8.2%	166.8	266.4	147.8	159.8	176.0	1,414	9.7%
	Q4	162.5	252.7	132.3	155.6	157.1	146	8.8%	167.7	269.1	148.6	160.5	176.5	1,338	9.1%
2011	1Q	164.0	257.5	134.3	157.1	158.4	152	9.0%	167.9	271.2	150.2	161.6	178.8	1,455	9.8%
	2Q	163.7	258.9	132.8	158.2	160.6	144	8.5%	168.4	273.9	150.6	162.6	181.9	1,470	9.8%
	3Q	165.4	262.4	135.4	158.7	160.9	152	8.8%	169.2	276.8	152.7	163.6	182.6	1,502	9.9%
	4Q	166.1	266.4	136.2	160.5	161.3	164	9.4%	170.4	279.4	154.5	164.0	182.3	1,494	9.8%

Note: Data are based on Chain Weighted Indexes.

Source: www.bea.gov, www.cansim2.statcan.ca, www.federalreserve.gov

TREND IN INTEREST RATES, DIVIDEND YIELDS, AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

	Canada												
	Government Securities											Moody's U.S. Utility Long-Term	Exchange Rate
	T-Bills		10 Year		Long-Term		Bonds Over	Inflation	A-Rated	Median Utility	A-Rated Utility/ Long Canada Bond		
Year	Canadian	U.S. [1/]	Canadian	U.S.	Canadian	U.S. [2/]	10 Years [3/]	Indexed Bonds	Utility Bonds [4/]	Dividend Yield [5/]	Yield Spread	A-Rated Bonds	(Cdn$/US$)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Annual													
1990	12.81	7.49	10.76	8.55	10.69	8.61	10.85		12.13		1.44	9.86	0.86
1991	8.73	5.38	9.42	7.86	9.72	8.14	9.76		11.00		1.28	9.36	0.84
1992	6.59	3.43	8.05	7.01	8.68	7.67	8.77	4.62	10.01		1.33	8.69	0.82
1993	4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	9.08	6.08	1.22	7.59	0.77
1994	5.54	4.34	8.43	7.08	8.69	7.39	8.63	4.41	9.81	6.12	1.12	8.30	0.73
1995	6.89	5.44	8.08	6.58	8.41	6.85	8.28	4.68	9.29	6.42	0.88	7.89	0.73
1996	4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	8.38	5.66	0.63	7.75	0.73
1997	3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	7.19	4.57	0.53	7.60	0.72
1998	4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	6.38	4.23	0.79	7.04	0.68
1999	4.69	4.71	5.55	5.68	5.72	5.91	5.69	4.07	6.92	5.00	1.20	7.62	0.67
2000	5.45	5.85	5.89	5.98	5.71	5.88	5.89	3.69	7.05	5.63	1.34	8.24	0.67
2001	3.78	3.34	5.49	4.99	5.77	5.50	5.76	3.59	7.10	4.57	1.33	7.74	0.65
2002	2.55	1.63	5.27	4.56	5.67	5.41	5.65	3.49	7.08	3.97	1.41	7.34	0.64
2003	2.86	1.03	4.78	4.02	5.31	5.03	5.26	3.04	6.65	3.80	1.33	6.54	0.72
2004	2.21	1.44	4.55	4.27	5.11	5.08	5.05	2.34	6.14	3.69	1.03	6.14	0.77
2005	2.73	3.29	4.04	4.27	4.38	4.52	4.36	1.81	5.43	3.23	1.05	5.62	0.83
2006	4.05	4.86	4.21	4.79	4.26	4.87	4.28	1.67	5.36	3.19	1.09	6.06	0.89
2007	4.13	4.42	4.25	4.58	4.30	4.80	4.31	1.95	5.52	3.26	1.22	6.06	0.94
2008	2.26	1.28	3.56	3.61	4.04	4.22	4.03	1.90	6.29	3.62	2.26	6.54	0.94
2009	0.31	0.15	3.27	3.29	3.85	4.10	3.85	1.86	6.10	4.20	2.24	5.99	0.88
2010	0.59	0.14	3.17	3.14	3.70	4.17	3.63	1.36	5.20	3.78	1.51	5.38	0.97
2011	0.91	0.06	2.76	2.75	3.26	3.86	3.19	0.92	4.82	3.50	1.56	5.00	1.02
2012 (Jun)	0.93	0.08	1.92	1.88	2.50	2.99	2.39	0.45	4.09	3.62	1.59	4.26	0.99

[1/] Rates on new issues.
[2/] 30-year maturities through January 2002. Theoretical 30-year yield, February 2002 to January 2006, when no 30-year Treasury bonds were issued. The theoretical 30-year Treasury bond yield represents the yield on all outstanding Treasury bonds with a term to maturity greater than 25 years plus an extrapolation factor published by the U.S. Department of the Treasury to allow the estimation of a 30-year rate; 30-year maturities February 2006 forward.
[3/] Terms to maturity of l0 years or more.
[4/] Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of long-term utility bonds maintained by Foster Associates from September 2000 forward.
[5/] Monthly dividend yields of Canadian Utilities, Emera Inc., Enbridge Inc., Fortis Inc., and Transcanada Corp.

Source: www.bankofcanada.ca; www.federalreserve.gov, www.globeandmail.com; www.moodys.com
www.ustreas.gov

TREND IN INTEREST RATES, DIVIDEND YIELDS, AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

		Canada												
		Government Securities											Moody's	
		T-Bills		10 Year		Long-Term		Bonds Over	Inflation	A-Rated	Median Utility	A-Rated Utility/ Long Canada Bond	U.S. Utility Long-Term	Exchange Rate
Year		Canadian	U.S. [1/]	Canadian	U.S.	Canadian	U.S. [2/]	10 Years [3/]	Indexed Bonds	Utility Bonds [4/]	Dividend Yield [5/]	Yield Spread	A-Rated Bonds	(Cdn$/US$)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2005	Q1	2.47	2.67	4.27	4.33	4.72	4.70	4.69	2.05	5.78	3.58	1.06	5.72	0.82
	Q2	2.46	3.01	3.93	4.05	4.39	4.36	4.35	1.86	5.47	3.38	1.09	5.43	0.81
	Q3	2.73	3.50	3.88	4.21	4.20	4.39	4.19	1.75	5.20	2.92	0.99	5.49	0.84
	Q4	3.25	4.00	4.07	4.49	4.19	4.63	4.21	1.59	5.25	3.04	1.06	5.82	0.85
2006	Q1	3.70	4.57	4.18	4.65	4.23	4.70	4.25	1.53	5.32	3.28	1.09	5.92	0.87
	Q2	4.17	4.84	4.51	5.11	4.54	5.19	4.57	1.81	5.65	3.39	1.10	6.41	0.90
	Q3	4.14	5.00	4.14	4.79	4.21	4.91	4.23	1.67	5.34	3.18	1.12	6.09	0.89
	Q4	4.16	5.04	4.00	4.59	4.07	4.70	4.08	1.68	5.13	2.92	1.06	5.82	0.87
2007	Q1	4.17	5.11	4.10	4.68	4.17	4.82	4.18	1.77	5.23	3.19	1.06	5.92	0.86
	Q2	4.29	4.82	4.39	4.85	4.35	4.98	4.38	1.94	5.49	3.34	1.14	6.08	0.92
	Q3	4.17	4.26	4.43	4.64	4.45	4.86	4.46	2.09	5.75	3.36	1.30	6.19	0.97
	Q4	3.90	3.48	4.09	4.16	4.21	4.53	4.21	2.01	5.61	3.13	1.39	6.05	1.02
2008	Q1	2.76	1.73	3.65	3.55	4.07	4.35	4.03	1.80	5.65	3.31	1.58	6.16	0.99
	Q2	2.60	1.74	3.68	3.94	4.10	4.58	4.07	1.60	5.84	3.63	1.74	6.30	0.99
	Q3	2.23	1.44	3.66	3.89	4.11	4.44	4.13	1.78	6.21	3.66	2.10	6.58	0.95
	Q4	1.45	0.19	3.26	3.06	3.88	3.50	3.91	2.42	7.47	3.87	3.60	7.13	0.82
2009	Q1	0.61	0.24	2.99	2.87	3.68	3.62	3.65	2.13	7.06	4.38	3.38	6.44	0.80
	Q2	0.21	0.16	3.28	3.39	3.90	4.24	3.86	1.97	6.27	4.37	2.37	6.35	0.87
	Q3	0.22	0.16	3.38	3.41	3.89	4.17	3.94	1.76	5.49	4.14	1.60	5.54	0.92
	Q4	0.21	0.06	3.42	3.49	3.95	4.35	3.96	1.57	5.56	3.91	1.62	5.65	0.94
2010	Q1	0.20	0.12	3.43	3.69	4.01	4.59	3.94	1.54	5.45	3.91	1.44	5.80	0.96
	Q2	0.46	0.17	3.36	3.32	3.80	4.22	3.73	1.45	5.37	4.09	1.57	5.46	0.96
	Q3	0.74	0.15	2.88	2.65	3.49	3.73	3.42	1.35	5.00	3.71	1.51	4.96	0.96
	Q4	0.97	0.14	2.99	2.91	3.48	4.15	3.42	1.11	4.98	3.42	1.50	5.31	0.99
2011	Q1	0.95	0.13	3.31	3.44	3.73	4.53	3.68	1.25	5.18	3.42	1.46	5.56	1.02
	Q2	0.96	0.04	3.13	3.18	3.58	4.33	3.50	1.00	5.07	3.56	1.49	5.37	1.04
	Q3	0.88	0.05	2.48	2.32	3.05	3.54	2.96	0.83	4.65	3.58	1.60	4.74	1.01
	Q4	0.86	0.01	2.13	2.05	2.70	3.04	2.61	0.58	4.37	3.46	1.67	4.35	0.99
2012	Q1	0.91	0.07	1.99	2.01	2.59	3.12	2.48	0.44	4.10	3.62	1.51	4.35	1.00
	Q2	0.95	0.09	1.84	1.74	2.41	2.85	2.31	0.45	4.08	3.62	1.67	4.17	0.99
2008	Jan	3.38	1.96	3.88	3.67	4.18	4.35	4.16	1.96	5.67	3.07	1.49	6.07	1.00
	Feb	3.04	1.85	3.64	3.53	4.09	4.41	4.04	1.85	5.66	3.44	1.57	6.22	1.02
	Mar	1.87	1.38	3.43	3.45	3.94	4.30	3.88	1.60	5.63	3.42	1.69	6.20	0.97
	Apr	2.68	1.43	3.58	3.77	4.08	4.49	4.02	1.72	5.78	3.60	1.70	6.22	0.99
	May	2.64	1.89	3.71	4.06	4.13	4.72	4.09	1.61	5.83	3.66	1.70	6.36	0.99
	Jun	2.48	1.90	3.74	3.99	4.08	4.53	4.10	1.47	5.89	3.65	1.81	6.32	0.98
	Jul	2.39	1.68	3.70	3.99	4.10	4.59	4.11	1.54	5.92	3.63	1.82	6.44	0.98
	Aug	2.40	1.72	3.53	3.83	4.01	4.43	4.02	1.57	6.09	3.58	2.08	6.32	0.94
	Sep	1.89	0.92	3.75	3.85	4.23	4.31	4.25	2.23	6.64	3.77	2.41	6.98	0.94
	Oct	1.85	0.46	3.76	4.01	4.28	4.35	4.33	2.51	7.61	3.80	3.33	8.01	0.82
	Nov	1.67	0.01	3.32	2.93	3.90	3.45	3.96	2.65	7.48	3.74	3.58	7.18	0.81
	Dec	0.83	0.11	2.69	2.25	3.45	2.69	3.45	2.10	7.33	4.07	3.88	6.20	0.82
2009	Jan	0.86	0.24	3.06	2.87	3.77	3.58	3.80	2.27	7.33	4.11	3.56	6.52	0.81
	Feb	0.59	0.26	3.12	3.02	3.70	3.71	3.70	2.32	7.07	4.33	3.37	6.38	0.79
	Mar	0.39	0.21	2.79	2.71	3.57	3.56	3.46	1.81	6.78	4.70	3.21	6.41	0.79
	Apr	0.20	0.14	3.09	3.16	3.84	4.05	3.74	2.05	6.71	4.70	2.87	6.55	0.84
	May	0.20	0.14	3.39	3.47	3.99	4.34	3.93	2.00	6.14	4.33	2.15	6.53	0.91
	Jun	0.24	0.19	3.36	3.53	3.86	4.32	3.91	1.86	5.94	4.09	2.08	5.96	0.86
	Jul	0.24	0.18	3.46	3.52	3.95	4.31	4.01	1.73	5.54	4.08	1.59	5.68	0.93
	Aug	0.20	0.15	3.37	3.40	3.89	4.18	3.94	1.81	5.45	4.18	1.56	5.54	0.91
	Sep	0.22	0.14	3.31	3.31	3.84	4.03	3.87	1.74	5.49	4.16	1.65	5.41	0.93
	Oct	0.22	0.05	3.42	3.41	3.92	4.23	3.95	1.60	5.49	4.11	1.57	5.55	0.93
	Nov	0.21	0.06	3.22	3.21	3.84	4.20	3.83	1.58	5.50	3.98	1.66	5.54	0.95
	Dec	0.19	0.06	3.61	3.85	4.08	4.63	4.09	1.53	5.69	3.63	1.61	5.86	0.96
2010	Jan	0.16	0.08	3.34	3.63	3.94	4.51	3.90	1.49	5.42	3.75	1.48	5.73	0.94
	Feb	0.16	0.13	3.39	3.61	4.02	4.55	3.94	1.58	5.49	4.11	1.47	5.77	0.95
	Mar	0.28	0.16	3.56	3.84	4.07	4.72	3.99	1.56	5.44	3.88	1.37	5.89	0.98
	Apr	0.39	0.16	3.65	3.69	4.01	4.53	3.94	1.49	5.40	3.99	1.39	5.60	0.99
	May	0.50	0.16	3.36	3.31	3.73	4.22	3.65	1.45	5.46	4.15	1.73	5.57	0.96
	Jun	0.50	0.18	3.08	2.97	3.65	3.91	3.59	1.42	5.24	4.12	1.59	5.21	0.94
	Jul	0.66	0.15	3.11	2.94	3.69	3.98	3.62	1.51	5.17	3.83	1.48	5.17	0.97
	Aug	0.70	0.14	2.78	2.47	3.44	3.52	3.36	1.34	5.01	3.80	1.57	4.78	0.94
	Sep	0.87	0.16	2.75	2.53	3.35	3.69	3.27	1.20	4.82	3.51	1.47	4.93	0.97
	Oct	0.92	0.12	2.80	2.63	3.44	3.99	3.32	1.09	4.89	3.46	1.45	5.21	0.98
	Nov	1.01	0.17	3.07	2.81	3.48	4.12	3.45	1.12	5.04	3.49	1.56	5.28	0.97
	Dec	0.97	0.12	3.11	3.30	3.52	4.34	3.48	1.11	5.00	3.30	1.48	5.45	1.01
2011	Jan	0.96	0.15	3.27	3.42	3.73	4.58	3.68	1.38	5.18	3.25	1.45	5.61	1.00
	Feb	0.96	0.15	3.30	3.42	3.70	4.49	3.65	1.22	5.14	3.52	1.44	5.51	1.03
	Mar	0.93	0.09	3.35	3.47	3.75	4.51	3.70	1.15	5.23	3.50	1.48	5.57	1.03
	Apr	0.98	0.04	3.20	3.32	3.69	4.40	3.62	1.00	5.19	3.57	1.50	5.46	1.05
	May	0.96	0.06	3.07	3.05	3.49	4.22	3.38	0.98	4.97	3.51	1.48	5.23	1.03
	Jun	0.93	0.03	3.11	3.18	3.55	4.38	3.49	1.03	5.04	3.59	1.49	5.41	1.04
	Jul	0.91	0.10	2.79	2.82	3.29	4.12	3.21	0.79	4.73	3.66	1.44	5.09	1.05
	Aug	0.93	0.02	2.49	2.23	3.10	3.60	3.00	0.88	4.74	3.55	1.64	4.74	1.02
	Sep	0.80	0.02	2.15	1.92	2.77	2.90	2.68	0.82	4.49	3.52	1.72	4.38	0.96
	Oct	0.89	0.01	2.29	2.17	2.92	3.16	2.81	0.67	4.54	3.44	1.62	4.42	1.01
	Nov	0.86	0.01	2.15	2.08	2.69	3.06	2.61	0.61	4.41	3.46	1.72	4.38	0.98
	Dec	0.82	0.02	1.94	1.89	2.49	2.89	2.41	0.45	4.17	3.48	1.68	4.24	0.98
2012	Jan	0.88	0.06	1.89	1.83	2.50	2.94	2.40	0.38	4.05	3.47	1.55	4.22	0.99
	Feb	0.93	0.08	1.98	1.98	2.60	3.08	2.48	0.44	4.10	3.68	1.50	4.30	1.01
	Mar	0.91	0.07	2.11	2.23	2.66	3.35	2.55	0.51	4.14	3.72	1.48	4.54	1.00
	Apr	1.05	0.10	2.04	1.95	2.61	3.12	2.51	0.57	4.22	3.50	1.61	4.33	1.01
	May	0.93	0.07	1.74	1.59	2.29	2.67	2.16	0.34	4.00	3.65	1.71	4.04	0.97
	Jun	0.87	0.09	1.74	1.67	2.33	2.76	2.25	0.44	4.03	3.72	1.70	4.13	0.98

[1/] Rates on new issues.
[2/] Theoretical 30-year yield, 2005 to January 2006. 30-year maturities February 2006 forward.
[3/] Terms to maturity of l0 years or more.
[4/] Series of long-term utility bonds maintained by Foster Associates.
[5/] Monthly dividend yields of Canadian Utilities, Emera Inc., Enbridge Inc., Fortis Inc., and Transcanada Corp.
Note: Monthly data reflect rate in effect at end of month.

Source: www.bankofcanada.ca; www.federalreserve.gov, www.globeandmail.com; www.moodys.com
RBC Capital Markets, www.ustreas.gov

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES
(Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
Gas Distributors									
AltaGas Utilities	12/11	AUC	2011-474	57.00	0.00	43.00	8.75	3.60	
ATCO Gas	12/11	AUC	2011-474	53.09	7.91	39.00	8.75	3.60	
Enbridge Gas Distribution Inc	1/04; 7/07; 2/08	OEB	RP-2002-0158; EB-2006-0034; EB-2007-0615	61.33	2.67	36.00	8.39	4.23	
FortisBC Energy Inc.	12/09	BCUC	G-158-09	60.00	0.00	40.00	9.50	4.30	
FortisBC Energy (Vancouver Island)	12/09	BCUC	G-14-06; G-158-09	60.00	0.00	40.00	10.00	4.30	
FortisBC Energy Inc (Whistler)	4/09; 12/09	BCUC	G-35-09; G-158-09	60.00	0.00	40.00	10.00	4.30	
Gazifère	11/10;12/11	Régie	D-2010-147;D-2011-189	60.00	0.00	40.00	8.29	3.10	
Gaz Métro	11/11	Régie	D-2011-182	54.00	7.50	38.50	8.90	4.00	
Pacific Northern Gas-West	12/09; 5/10	BCUC	G-158-09; G-84-10	51.15	3.85	45.00	10.15	4.30	
Pacific Northern Gas-Fort St. John/Dawson Creek	12/09; 5/10	BCUC	G-158-09; G-84-10	60.00	0.00	40.00	9.90	4.30	
Pacific Northern Gas-Tumbler Ridge	12/09; 5/10	BCUC	G-158-09; G-84-10	60.00	0.00	40.00	10.15	4.30	
Union Gas	1/04; 5/06; 1/08	OEB	RP-2002-0158; EB-2006-0520; EB-2007-0606	60.60	3.40	36.00	8.54	4.23	
Electric Utilities									
AltaLink	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
ATCO Electric									
Transmission	12/11	AUC	2011-474	52.81	10.19	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	50.95	10.05	39.00	8.75	3.60	
ENMAX									
Transmission	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
EPCOR									
Transmission	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
FortisAlberta Inc.	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
FortisBC Inc.	5/05; 12/09	BCUC	G-52-05; G-158-09	60.00	0.00	40.00	9.90	4.30	
Hydro One Transmission	12/10; 3/12	OEB	EB-2010-0002; Letter Cost of Capital Parameters	60.00	0.00	40.00	9.12	2.93	
Maritime Electric	7/10	IRAC	UE-10-03	59.50	0.00	40.50	9.75	n/a	[1]
Newfoundland Power	12/09; 12/10	NLPub	P.U. 46 (2009); P.U. 32 (2010)	54.27	1.04	44.69	8.38	3.72	
Nova Scotia Power	11/11	NSUARB	2011 NSUARB 184	53.30	9.20	37.50	9.20	n/a	
Ontario Electricity Distributors	12/09; 3/12	OEB	EB-2009-0084; Letter Cost of Capital Parameters	60.00	0.00	40.00	9.12	2.93	
Ontario Power Generation	3/11	OEB	EB-2010-0008	53.00	0.00	47.00	9.55	3.85	
Gas Pipelines									
Foothills Pipe Lines Ltd.	6/10	NEB	TG-03-2010	60.00	0.00	40.00	9.70	n/a	
Nova Gas Transmission Ltd.	9/10	NEB	TG-05-2010	60.00	0.00	40.00	9.70	n/a	
TransCanada PipeLines	5/07; 11/10	NEB	RH-2-94;TG-06-2007; NEB Letter 11-10	60.00	0.00	40.00	8.08	3.72	
Trans Québec & Maritimes Pipeline	3/09; 11/10	NEB	RH-1-2008; TG-07-2010	60.00	0.00	40.00	9.70	n/a	[2]
Westcoast Energy	1/11	NEB	TG-01-2011	60.00	0.00	40.00	9.70	n/a	

[1] In 2010, the Electric Power Amendment Act reduced electricity rates and froze them until March 2013.
[2] Settlement for 2010-2012 does not specify return on rate base; AFUDC rate, income taxes and capital variances based on a 9.7% ROE, 60%/40% debt/equity capital structure and TQM's embedded cost of debt.
Source: Regulatory Decisions.

RATES OF RETURN ON COMMON EQUITY ADOPTED BY
REGULATORY BOARDS FOR CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Gas Distributors																							
AltaGas Utilities	NA	13.50	13.25	NA	NA	12.00	11.75	11.75	11.75	11.75	9.90	9.70	9.70	9.50	9.60	9.50	8.93	8.51	8.75	9.00	9.00	8.75	8.75
ATCO Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50	8.93	8.51	8.75	9.00	9.00	8.75	8.75
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57	8.74	8.39	8.39	8.39	8.39	8.39	8.39
FortisBC Energy [1/]	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03	8.80	8.37	8.62	8.47	9.50	9.50	9.50
Gaz Métro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69	8.95	8.73	9.05	8.76	9.20	9.09	8.90
Pacific Northern Gas [1/]	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	9.68	9.45	9.02	9.27	9.12	10.15	10.15	10.15
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	9.95	9.95	9.62	9.62	8.89	8.54	8.54	8.54	8.54	8.54	8.54
Mean of Gas Distributors	**13.90**	**13.60**	**13.09**	**12.51**	**11.65**	**12.03**	**11.69**	**11.07**	**10.48**	**9.96**	**9.84**	**9.68**	**9.68**	**9.73**	**9.52**	**9.51**	**8.96**	**8.58**	**8.77**	**8.75**	**9.11**	**9.02**	**9.00**
Electric Utilities																							
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50	8.93	8.51	8.75	9.00	9.00	8.75	8.75
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	[2/]	[2/]	[2/]	[2/]	[2/]	[2/]	9.40	9.60	9.50	8.93	8.51	8.75	9.00	9.00	8.75	8.75
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50	8.93	8.51	8.75	9.00	9.00	8.75	8.75
FortisBC Inc. [1/]	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43	9.20	8.77	9.02	8.87	9.90	9.90	9.90
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24	9.24	8.60	8.95	8.95	9.00	8.38	8.80
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55	9.55	9.55	NA	9.35	NA	NA	9.20
Ontario Electricity Distributors	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.35	9.88	9.88	9.88	9.88	9.88	9.88	9.00	9.00	8.57	8.01	9.85	9.58	9.42
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	[2/]	[3/]	9.25	9.25	NA	9.40	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.34**	**9.68**	**9.74**	**9.59**	**9.63**	**9.66**	**9.51**	**9.11**	**8.78**	**8.80**	**8.88**	**9.29**	**9.02**	**9.08**
Gas Pipelines (NEB)																							
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72	8.57	8.52	8.08	NA[4/]
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72	8.57	8.52	9.70	9.70
Mean of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**	**8.46**	**8.72**	**8.57**	**8.52**	**8.89**	**9.70**
Mean of All Companies	**13.68**	**13.56**	**12.97**	**12.16**	**11.50**	**12.12**	**11.39**	**10.93**	**10.30**	**9.69**	**9.80**	**9.69**	**9.62**	**9.70**	**9.59**	**9.51**	**9.01**	**8.65**	**8.77**	**8.79**	**9.10**	**9.00**	**9.08**

[1/] Allowed ROE for 2009 for first six months
[2/] Negotiated settlement, details not available.
[3/] Negotiated settlement, implicit ROE made public is 10.5%.
[4/] Rate case ongoing for 2012.

Note: The allowed ROEs for ENMAX Distribution, EPCOR Distribution and EPCOR Transmission have been identical to those of the other Alberta utilities since 2004 (ENMAX Transmission since 200
Source: Regulatory Decisions

DEBT RATINGS OF CANADIAN UTILITIES

	Ratings						
	DBRS		Moody's		S&P		
Company	Issuer Rating (1)	Debt Rating (2)	Issuer Rating (3)	Debt Rating (4)	Corporate Credit Rating (5)	Debt Rating (6)	S&P Business Risk Profile (7)
Gas Distributors							
Enbridge Gas Distribution		A (Unsecured)			A-	A- (Senior Unsecured)	Excellent
FortisBC Energy Inc.		A (Unsecured)		A3 (Senior Unsecured) A1 (Senior Secured)		[1]	
FortisBC Energy Inc. (Vancouver Island)		BBB(high) (Debentures)		A3 (Senior Unsecured)			
Gaz Métro Inc.		A (First Mortgage)			A-	A (Senior Secured)	Excellent
Pacific Northern Gas		[2]					
Union Gas Limited		A (Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
Median		**A**		**A3**	**A-**	**A-**	**Excellent**
Electric Utilities							
AltaLink L.P.		A (Senior Secured)			A-	A- (Senior Secured)	Excellent
CU Inc.		A(high) (Unsecured)			A	A (Senior Unsecured)	Excellent
Enersource	A	A (Senior Unsecured)					
ENMAX Corp.		A(low) (Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
ENTEGRUS Inc. [3]					A		Excellent
EPCOR Utilities Inc.		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
FortisAlberta Inc.		A(low) (Senior Unsecured)		Baa1 (Senior Unsecured)	A-	A- (Senior Unsecured)	Excellent
FortisBC Inc.		A(low) (Unsecured)		Baa1 (Senior Unsecured)			
Guelph Hydro Electric Systems					A	A (Senior Unsecured)	Excellent
Hamilton Utilities					A	A (Senior Unsecured)	Excellent
Hydro One Inc.		A(high) (Senior Unsecured)		A1 (Senior Unsecured) [4]	A+ [4]	A+ (Senior Unsecured) [4]	Excellent
Hydro Ottawa Holding Inc.		A (Senior Unsecured)			A	A (Senior Unsecured)	Excellent
London Hydro					A		Excellent
Maritime Electric					BBB+	A- (Senior Secured)	Strong
Newfoundland Power		A (First Mortgage)	Baa1	A2 (First Mortgage)			
Nova Scotia Power		A(low) (Unsecured)	[5]	[5]	BBB+	BBB+ (Senior Unsecured)	Strong
Ontario Power Generation		A(low) (Unsecured)			A-		Strong
Toronto Hydro		A(high) (Senior Unsecured)			A	A (Senior Unsecured)	Excellent
Veridian Corp.	A						
Median		**A**		**A3**	**A**	**A/A-**	**Excellent**
Pipelines							
Enbridge Pipelines Inc.		A (Unsecured)			A-	A- (Senior Unsecured)	Excellent
NOVA Gas Transmission Ltd.		A (Unsecured)		A3 (Senior Unsecured)	A-	A- (Senior Unsecured)	
Trans Québec & Maritimes Pipeline		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
TransCanada PipeLines Ltd.		A (Unsecured)	A3	A3 (Senior Unsecured)	A-	A- (Senior Unsecured)	Excellent
Westcoast Energy Inc.		A(low) (Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
Median		**A**		**A3**	**A-**	**A-**	**Excellent/Strong**
Medians							
All Companies		**A**		**A3**	**A-**	**A-**	**Excellent**
All Investor-Owned Companies		**A**		**A3**	**A-**	**A-**	**Excellent**
All Gas & Electric Investor-Owned Companies Currently Rated by DBRS excl. FEI		**A**		**Baa1**	**A-**	**A-**	**Excellent**

[1] S&P ratings affirmed at AA- for Senior Secured Debt and A for Unsecured Debt, then withdrawn September 23, 2010.
[2] DBRS rating discontinued March 12, 2012. Previously BBB(low) for Senior Secured.
[3] Previously Chatham-Kent Energy Inc.
[4] Moody's rating reflects application of methodology for government-related issuers. Implied senior unsecured rating of Baa1. S&P stand-alone rating is A.
[5] Ratings withdrawn at request of company March 2010; unsecured debt previously rated Baa1.

TOTAL CAPITAL STRUCTURE RATIOS OF CANADIAN UTILITIES WITH RATED DEI
(2011)

Company	Total Debt [2/]	Preferred Stock [3/]	Common Stock Equity [4/]
	(1)	(2)	(3)
Gas Distributors [1/]			
Enbridge Gas Distributior	57.3%	2.1%	40.5%
FortisBC Energy Inc.	59.7%	0.0%	40.3%
Gaz Métro L.P.	60.0%	0.0%	40.0%
Pacific Northern Gas	48.0%	2.6%	49.3%
Union Gas Limitec	61.5%	2.5%	36.0%
Median	**59.7%**	**2.1%**	**40.3%**
Electric Utilities			
AltaLink L.P.	56.7%	0.0%	43.3%
CU Inc.	56.0%	6.9%	37.2%
Enersource [5/]	55.0%	0.0%	45.0%
ENMAX Corp.	45.6%	0.0%	54.4%
EPCOR Utilities Inc.	42.0%	0.0%	58.0%
FortisAlberta Inc.	57.4%	0.0%	42.6%
FortisBC Inc.	58.4%	0.0%	41.6%
Hamilton Utilities	37.4%	0.0%	62.6%
Hydro One Inc.	55.5%	2.2%	42.3%
Hydro Ottawa Holding Inc. [5/]	42.3%	0.0%	57.7%
London Hydrc	43.2%	0.0%	56.8%
Maritime Electric	56.5%	0.0%	43.5%
Newfoundland Power	54.7%	1.0%	44.2%
Nova Scotia Power [6/]	57.9%	3.8%	38.3%
Toronto Hydrc	57.0%	0.0%	43.0%
Veridian Corp. [5/]	44.1%	0.0%	55.9%
Median	**55.2%**	**0.0%**	**43.9%**
Pipelines			
Enbridge Pipelines Inc.	52.9%	0.0%	47.1%
Nova Gas Transmission Ltd	65.4%	0.0%	34.6%
Trans Québec & Maritimes Pipeline	59.9%	0.0%	40.1%
TransCanada PipeLines Ltd	53.3%	0.9%	45.8%
Westcoast Energy Inc.	59.0%	3.6%	37.4%
Median	**59.0%**	**0.0%**	**40.1%**
Medians			
All Companies	**56.2%**	**0.0%**	**43.1%**
All Investor-Owned Companies	**57.4%**	**0.0%**	**40.5%**
All Gas & Electric Investor-Owned Companies Currently Rated by DBRS excl. FE	**57.4%**	**1.0%**	**40.5%**

[1/] The average of the four quarters ending December 2011 for gas distributors was used to better measure the actual sources of funds over the year due to the seasonal pattern of use of short-term debt.
[2/] Includes preferred securities classified as debt.

[3/] Includes preferred securities classified as equity and non-controlling interests in subsidiary company preferred shares.
[4/] Includes non-controlling interests in common shares of subsidiary companies.
[5/] 2010 capital structure.
[6/] Common equity ratio excludes Accumulated Other Comprehensive Income.

Notes:

Financial statements for FortisBC Energy (Vancouver Island) are not publicly available.

Source: Reports to Shareholders

TOTAL CAPITAL STRUCTURE RATIOS
OF INVESTOR-OWNED CANADIAN UTILITIES WITH RATED DEBT
(Short-Term and Long-Term Debt Separated)

Company	2008 Long-Term Debt 2/	2008 Short-Term Debt	2008 Preferred Stock 3/	2008 Common Stock Equity 4/	2009 Long-Term Debt 2/	2009 Short-Term Debt	2009 Preferred Stock 3/	2009 Common Stock Equity 4/
Gas Distributors 1/								
Enbridge Gas Distribution	49.0%	9.6%	2.1%	39.2%	48.7%	6.6%	2.3%	42.4%
FortisBC Energy Inc.	56.1%	9.5%	0.0%	34.5%	59.4%	4.8%	0.0%	35.8%
Gaz Métro L.P.	62.4%	1.4%	0.0%	36.2%	62.0%	1.0%	0.0%	37.0%
Pacific Northern Gas	44.9%	2.4%	3.0%	49.7%	45.9%	0.4%	3.0%	50.8%
Union Gas Limited	56.6%	4.0%	2.9%	36.5%	59.7%	0.0%	0.0%	40.3%
Median	**56.1%**	**4.0%**	**2.1%**	**36.5%**	**59.4%**	**1.0%**	**0.0%**	**40.3%**
Electric Utilities								
AltaLink L.P.	61.7%	0.0%	0.0%	38.3%	54.1%	0.0%	0.0%	45.9%
CU Inc.	56.4%	0.3%	5.1%	38.2%	53.6%	0.1%	7.7%	38.6%
FortisAlberta Inc.	60.0%	0.5%	0.0%	39.4%	56.4%	0.9%	0.0%	42.7%
FortisBC Inc.	59.1%	0.0%	0.0%	40.9%	59.2%	0.0%	0.0%	40.8%
Maritime Electric	53.6%	6.2%	0.0%	40.2%	52.4%	6.1%	0.0%	41.5%
Newfoundland Power	53.4%	0.0%	1.1%	45.5%	55.1%	0.0%	1.0%	43.8%
Nova Scotia Power 5/	54.3%	0.8%	4.7%	40.1%	51.3%	6.8%	4.6%	37.2%
Median	**56.4%**	**0.3%**	**0.0%**	**40.1%**	**54.1%**	**0.1%**	**0.0%**	**41.5%**
Pipelines								
Enbridge Pipelines Inc.	52.7%	7.0%	0.0%	40.4%	44.4%	12.7%	0.0%	42.9%
Nova Gas Transmission Ltd	61.4%	0.6%	0.0%	38.0%	63.8%	0.5%	0.0%	35.7%
Trans Québec & Maritimes Pipeline	69.9%	0.0%	0.0%	30.1%	62.9%	0.0%	0.0%	37.1%
TransCanada PipeLines Ltd	54.4%	5.0%	1.1%	39.5%	51.8%	4.7%	1.1%	42.4%
Westcoast Energy Inc.	51.3%	3.6%	4.8%	40.3%	57.1%	1.5%	5.4%	36.0%
Pipelines	**54.4%**	**3.6%**	**0.0%**	**39.5%**	**57.1%**	**1.5%**	**0.0%**	**37.1%**
Median All Companies	**56.1%**	**1.4%**	**0.0%**	**39.4%**	**55.1%**	**0.9%**	**0.0%**	**40.8%**
All Gas & Electric Investor-Owned Companies Currently Rated by DBRS excl. FEI	**56.6%**	**0.5%**	**1.1%**	**39.2%**	**55.1%**	**0.1%**	**0.0%**	**40.8%**

Company	2010 Long-Term Debt 2/	2010 Short-Term Debt	2010 Preferred Stock 3/	2010 Common Stock Equity 4/	2011 Long-Term Debt 2/	2011 Short-Term Debt	2011 Preferred Stock 3/	2011 Common Stock Equity 4/
Gas Distributors 1/								
Enbridge Gas Distribution	49.7%	6.7%	2.2%	41.3%	50.3%	7.0%	2.1%	40.5%
FortisBC Energy Inc.	56.2%	3.8%	0.0%	40.0%	56.6%	3.1%	0.0%	40.3%
Gaz Métro L.P.	61.7%	1.7%	0.0%	36.7%	59.0%	1.0%	0.0%	40.0%
Pacific Northern Gas	47.3%	1.6%	2.7%	48.4%	46.2%	1.8%	2.6%	49.3%
Union Gas Limited	55.4%	4.7%	2.5%	37.4%	57.0%	4.5%	2.5%	36.0%
Median	**55.4%**	**3.8%**	**2.2%**	**40.0%**	**56.6%**	**3.1%**	**2.1%**	**40.3%**
Electric Utilities								
AltaLink L.P.	56.0%	0.0%	0.0%	44.0%	52.3%	4.5%	0.0%	43.3%
CU Inc.	52.4%	1.0%	8.3%	38.3%	55.6%	0.4%	6.9%	37.2%
FortisAlberta Inc.	56.8%	0.5%	0.0%	42.7%	57.1%	0.3%	0.0%	42.6%
FortisBC Inc.	59.5%	0.0%	0.0%	40.5%	58.4%	0.0%	0.0%	41.6%
Maritime Electric	47.1%	9.6%	0.0%	43.3%	55.6%	0.9%	0.0%	43.5%
Newfoundland Power	53.7%	0.0%	1.0%	45.2%	54.7%	0.0%	1.0%	44.2%
Nova Scotia Power 5/	58.1%	1.5%	4.1%	36.4%	56.1%	1.8%	3.8%	38.3%
Median	**56.0%**	**0.5%**	**0.0%**	**42.7%**	**55.6%**	**0.4%**	**0.0%**	**42.6%**
Pipelines								
Enbridge Pipelines Inc.	46.7%	7.7%	0.0%	45.6%	47.0%	4.8%	0.0%	48.2%
Nova Gas Transmission Ltd	55.8%	7.2%	0.0%	37.1%	61.7%	3.7%	0.0%	34.6%
Trans Québec & Maritimes Pipeline	60.0%	0.0%	0.0%	40.0%	59.9%	0.0%	0.0%	40.1%
TransCanada PipeLines Ltd	51.5%	5.5%	1.0%	42.0%	47.7%	4.4%	0.9%	47.0%
Westcoast Energy Inc.	57.6%	0.4%	5.2%	36.9%	55.9%	2.9%	3.6%	37.6%
Median	**55.8%**	**5.5%**	**0.0%**	**40.0%**	**55.9%**	**3.7%**	**0.0%**	**40.1%**
Medians All Companies	**55.8%**	**1.6%**	**0.0%**	**40.5%**	**55.9%**	**1.8%**	**0.0%**	**40.5%**
All Gas & Electric Investor-Owned Companies Currently Rated by DBRS excl. FEI	**56.0%**	**1.0%**	**1.0%**	**40.5%**	**56.1%**	**1.0%**	**1.0%**	**40.5%**

1/ The average of the four quarters ending December for gas distributors was used to better measure
2/ Includes preferred securities classified as debt.
3/ Includes preferred securities classified as equity and non-controlling interests in subsidiary company
4/ Includes non-controlling interests in common shares of subsidiary companies.
5/ 2011 Common equity ratio excludes Accumulated Other Comprehensive Income.

Notes:
FortisBC Energy (Vancouver Island) excluded as financial statements not publicly availabl
Source: Reports to Shareholders

CAPITAL STRUCTURE RATIOS OF SAMPLE OF U.S. UTILITIES
(Four Quarters Ending December 2011)

Company	Total Debt [1/] (1)	Preferred Stock [2/] (2)	Common Stock Equity [3/] (3)
AGL Resources Inc.	56.6	0.0	43.4
Alliant Energy Corp.	47.3	2.6	50.1
Atmos Energy Corp.	50.3	0.0	49.7
Consolidated Edison	48.3	1.0	50.8
Integrys Energy Group Inc.	43.9	0.9	55.2
Northwest Natural Gas	53.0	0.0	47.0
Piedmont Natural Gas [4/]	48.6	0.0	51.4
Southern Company	53.9	1.8	44.3
Vectren Corp.	54.8	0.0	45.2
WGL Holdings Inc.	36.5	1.4	62.1
Wisconsin Energy Corp.	51.6	0.6	47.8
Xcel Energy Inc.	54.3	0.4	45.3
Median	**51.0**	**0.5**	**48.7**

[1/] Includes preferred securities classified as debt.

[2/] Includes preferred securities classified as equity and non-controlling interests in subsidiary company preferred shares.

[3/] Includes non-controlling interests in common shares of subsidiary companies.

[4/] Trailing four quarters ending October 31, 2011.

Source: Reports to Shareholders.

CREDIT METRICS OF CANADIAN UTILITIES WITH RATED DEBT

Company	EBIT Coverage 2008	2009	2010	3 Year Average		FFO Interest Coverage 2008	2009	2010	3 Year Average		FFO To Debt 2008	2009	2010	3 Year Average	
Gas Distributors															
Enbridge Gas Distribution	2.30	2.40	2.30	2.33		3.30	3.50	3.40	3.40		16.30	18.10	16.30	16.90	
FortisBC Energy Inc.	1.90	1.90	2.10	1.97	1/	2.50	2.60	2.70	2.60	2/	9.80	10.20	10.60	10.20	2/
Gaz Métro L.P.	2.20	2.20	2.40	2.27	3/	4.50	4.30	4.40	4.40		21.50	21.90	20.20	21.20	
Pacific Northern Gas	2.13	2.59	2.49	2.40	1/	2.26	2.60	3.90	2.92	4/	11.20	11.70	19.60	14.17	1/
Union Gas Limited	2.40	2.40	2.60	2.47		3.42	2.90	3.50	3.27		15.10	14.80	16.50	15.47	
Median	**2.20**	**2.40**	**2.40**	**2.33**		**3.30**	**2.90**	**3.50**	**3.27**		**15.10**	**14.80**	**16.50**	**15.47**	
Electric Utilities															
AltaLink L.P.	1.80	1.80	2.20	1.93		3.20	3.00	3.50	3.23		12.70	12.70	13.70	13.03	
CU Inc.	2.10	2.40	2.40	2.30		3.50	3.40	3.10	3.33		16.90	17.90	14.90	16.57	
Enersource	2.50	2.20	2.20	2.30		3.50	3.60	3.80	3.63		18.10	18.40	19.40	18.63	
ENMAX Corp.	2.70	2.30	1.90	2.30		3.80	3.30	3.10	3.40		13.70	13.60	13.70	13.67	
ENTEGRUS Inc.	3.50	3.70	4.00	3.73		5.50	5.40	5.50	5.47		34.90	29.50	29.70	31.37	
EPCOR Utilities Inc.	1.50	2.10	2.20	1.93		2.90	2.60	2.70	2.73		15.10	16.40	13.20	14.90	
FortisAlberta Inc.	2.00	2.10	2.00	2.03		3.80	3.80	3.90	3.83		12.50	13.20	13.90	13.20	
FortisBC Inc.	2.05	2.04	2.10	2.06	1/	2.80	2.90	3.00	2.90	2/	11.20	11.90	11.60	11.57	2/
Hamilton Utilities	3.30	3.30	3.10	3.23		5.10	4.60	5.20	4.97		35.30	29.60	27.00	30.63	
Hydro One Inc.	2.80	2.10	2.30	2.40		4.00	2.80	3.00	3.27		14.50	11.40	12.20	12.70	
Hydro Ottawa Holding Inc.	4.10	4.30	4.30	4.23		6.20	6.20	6.40	6.27		25.50	27.30	27.80	26.87	
London Hydro	2.90	3.30	3.10	3.10	3/	4.80	5.20	5.50	5.17		26.20	27.50	25.60	26.43	
Maritime Electric	2.30	2.30	2.40	2.33		3.20	3.10	2.80	3.03		17.40	16.30	13.60	15.77	
Newfoundland Power	2.53	2.40	2.41	2.45	1/	3.00	3.10	3.40	3.17	2/	15.80	15.00	17.60	16.13	2/
Nova Scotia Power	2.40	2.20	1.80	2.13		3.10	3.00	3.40	3.17		15.90	14.50	14.60	15.00	
Toronto Hydro	1.80	1.60	1.80	1.73		3.40	3.30	3.60	3.43		17.50	16.30	16.00	16.60	
Veridian Corp.	3.16	3.59	3.49	3.41	1/	na	na	na	na		22.40	33.50	29.00	28.30	1/
Median	**2.50**	**2.30**	**2.30**	**2.30**		**3.50**	**3.30**	**3.45**	**3.37**		**16.90**	**16.30**	**14.90**	**16.13**	
Pipelines															
Enbridge Pipelines Inc.	2.90	2.70	2.30	2.63		2.60	2.80	3.00	2.80		6.60	8.10	13.20	9.30	
NOVA Gas Transmission Ltd.	2.15	1.94	2.18	2.09	1/	na	na	na	na		14.20	14.20	14.30	14.23	1/
Trans Québec & Maritimes Pipeline	2.10	3.50	3.00	2.87		3.60	4.40	4.10	4.03		15.80	20.20	16.50	17.50	
TransCanada PipeLines Ltd.	2.30	1.90	1.80	2.00		3.00	2.80	2.90	2.90		13.00	12.40	11.90	12.43	
Westcoast Energy Inc.	2.70	2.40	2.60	2.57		3.50	2.90	3.50	3.30		17.90	13.30	15.80	15.67	
Median	**2.30**	**2.40**	**2.30**	**2.57**		**3.25**	**2.85**	**3.25**	**3.10**		**14.20**	**13.30**	**14.30**	**14.23**	
Medians															
All Companies	**2.30**	**2.30**	**2.30**	**2.33**		**3.42**	**3.10**	**3.50**	**3.30**		**15.80**	**15.00**	**15.80**	**15.67**	
All Investor Owned Companies	**2.20**	**2.30**	**2.30**	**2.30**		**3.20**	**3.00**	**3.40**	**3.20**		**15.10**	**14.20**	**14.60**	**15.00**	
All Gas & Electric Investor-Owned Companies Currently Rated by DBRS excl. FEI	**2.20**	**2.20**	**2.30**	**2.27**		**3.30**	**3.10**	**3.40**	**3.27**		**15.80**	**14.80**	**14.90**	**15.47**	

1/ Data from DBRS.
2/ Data from Moody's.
3/ 2010 data from S&P Credit Stats.
4/ Calculated from Annual Reports.
Source: Standard & Poor's Debt Rating Reports except where noted.

DBRS CREDIT METRICS FOR INVESTOR-OWNED CANADIAN UTILITIES

	EBIT Coverage						EBITDA Coverage					
	2007	2008	2009	2010	2011	2007-11 Average	2007	2008	2009	2010	2011	2007-11 Average
FortisBC Energy Inc	**1.99**	**1.92**	**1.96**	**2.17**	**2.17**	**2.04**	**2.72**	**2.62**	**2.72**	**3.04**	**3.00**	**2.82**
AltaLink L.P.	1.78	1.84	1.94	2.31	2.51	2.08	3.44	3.60	3.79	3.99	4.02	3.77
CU Inc.	2.30	2.20	2.00	2.40	3.00	2.38	3.90	3.80	3.00	3.70	4.30	3.74
Enbridge Gas Distribution	2.62	2.55	2.87	2.62	2.69	2.67	4.06	3.92	4.51	4.41	4.65	4.31
FortisAlberta Inc.	2.05	2.02	2.17	2.09	2.06	2.08	4.17	4.02	4.12	4.28	4.11	4.14
FortisBC Inc.	2.04	2.05	2.04	2.10	2.40	2.13	3.04	3.09	3.06	3.21	3.52	3.18
Gaz Metro	2.52	2.52	2.43	2.37	2.41	2.45	4.16	4.18	4.21	3.97	4.08	4.12
Newfoundland Power [1/]	2.20	2.53	2.40	2.41	2.38	2.38	3.17	3.84	3.71	3.71	4.01	3.69
Nova Scotia Power	2.83	2.67	2.69	2.04	1.67	2.38	4.30	4.22	4.42	3.72	3.23	3.98
Union Gas Limited	2.18	2.36	2.35	2.55	2.66	2.42	3.29	3.56	3.54	3.81	3.99	3.64
Median (Excluding FEI)	**2.20**	**2.36**	**2.35**	**2.37**	**2.41**	**2.38**	**3.90**	**3.84**	**3.79**	**3.81**	**4.02**	**3.77**

	Cash Flow/Total Debt					
	2007	2008	2009	2010	2011	2007-11 Average
FortisBC Energy Inc	**8.9**	**10.1**	**10.3**	**10.9**	**11.8**	**10.4**
AltaLink L.P.	12.6	13.3	14.8	14.8	13.2	13.7
CU Inc.	17.9	18.5	13.2	18.3	17.7	17.1
Enbridge Gas Distribution	16.8	17.1	21.7	19.5	19.4	18.9
FortisAlberta Inc.	18.2	15.7	15.9	17.4	16.5	16.7
FortisBC Inc.	11.4	11.4	12.2	12.4	13.3	12.1
Gaz Metro	29.9	21.5	22.3	18.4	24.0	23.2
Newfoundland Power [1/]	12.9	16.2	15.0	17.8	17.5	15.9
Nova Scotia Power	21.7	19.6	17.1	12.6	15.1	17.2
Union Gas Limited	15.1	14.9	14.1	16.7	16.2	15.4
Median (Excluding FEI)	**16.8**	**16.2**	**15.0**	**17.4**	**16.5**	**16.7**

[1/] Newfoundland Power 2011 data 12 months ending September 30, 2011.

Source: DBRS Reports

CREDIT METRICS FOR U.S. A-RATED GAS UTILITIES
(2010)

	EBIT Coverage (1)	FFO Interest Coverage (2)	FFO To Debt (3)	EBITDA Coverage (4)	Equity Ratio (5)
Indiana Gas	3.3	4.3	19.8	5.0	49.2%
Laclede Group	4.4	5.6	30.3	4.9	56.0%
Laclede Gas					
New Jersey Natural Gas	6.8	8.4	32.0	8.2	57.0%
Integrys Energy Group	3.7	5.7	25.2	4.0	49.3%
North Shore Gas					
Peoples Gas Light & Coke					
Northwest Natural Gas	3.8	5.4	21.9	5.3	44.3%
NStar LLC	5.0	6.1	21.2	5.8	39.6%
NStar Gas					
Piedmont Natural Gas	4.9	5.5	26.2	5.3	51.0%
Questar Gas	3.6	6.1	25.9	5.0	43.9%
Southern California Gas	4.6	5.7	27.1	6.9	42.3%
WGL Holdings	5.5	7.1	30.4	7.5	53.7%
Washington Gas Light					
Wisconsin Energy Corp	2.8	4.8	18.4	3.8	42.5%
Wisconsin Gas					
Median	**4.4**	**5.7**	**25.9**	**5.3**	**49.2%**

Source: Standard and Poor's

CREDIT METRICS OF SAMPLE OF U.S. UTILITIES

	EBIT Coverage				EBITDA Coverage			
Company	2008	2009	2010	3 Year Average	2008	2009	2010	3 Year Average
AGL Resources Inc.	3.70	4.10	4.40	4.07	4.90	5.50	5.80	5.40
Alliant Energy Corp.	3.20	2.60	3.30	3.03	4.60	3.90	4.80	4.43
Atmos Energy Corp.	2.88	2.63	2.93	2.81	4.20	3.90	4.20	4.10
Consolidated Edison	3.00	3.10	3.50	3.20	4.10	4.30	4.80	4.40
Integrys Energy Group Inc.	2.00	3.10	3.70	2.93	3.00	4.10	5.00	4.03
Northwest Natural Gas	3.80	3.80	3.80	3.80	5.60	5.10	5.10	5.27
Piedmont Natural Gas	3.70	4.90	4.90	4.50	4.70	6.20	5.30	5.40
Southern Company	3.30	3.20	3.60	3.37	4.80	4.50	4.90	4.73
Vectren Corp.	3.10	2.90	2.90	2.97	4.60	4.80	5.00	4.80
WGL Holdings Inc.	5.20	5.20	5.10	5.17	6.80	7.20	7.50	7.17
Wisconsin Energy Corp.	1.10	2.20	2.80	2.03	2.30	3.50	3.80	3.20
Xcel Energy Inc.	2.50	2.70	2.90	2.70	3.80	4.00	4.20	4.00
Median	**3.15**	**3.10**	**3.55**	**3.12**	**4.60**	**4.40**	**4.95**	**4.58**

	FFO Interest Coverage				FFO To Debt			
Company	2008	2009	2010	3 Year Average	2008	2009	2010	3 Year Average
AGL Resources Inc.	3.50	4.37	4.52	4.13	[1/] 18.80	20.90	20.00	19.90
Alliant Energy Corp.	4.50	4.50	5.30	4.77	20.00	22.70	24.80	22.50
Atmos Energy Corp.	4.24	3.91	4.48	4.21	21.95	21.36	25.52	22.94
Consolidated Edison	3.20	4.30	5.30	4.27	9.30	16.40	21.00	15.57
Integrys Energy Group Inc.	5.20	5.50	5.70	5.47	18.20	25.50	25.20	22.97
Northwest Natural Gas	5.30	3.70	5.40	4.80	21.90	17.40	21.90	20.40
Piedmont Natural Gas	4.60	6.40	5.50	5.50	21.80	24.80	26.20	24.27
Southern Company	4.20	4.40	4.90	4.50	17.20	18.10	20.10	18.47
Vectren Corp.	5.10	5.00	5.40	5.17	21.20	21.40	25.50	22.70
WGL Holdings Inc.	7.00	6.70	6.30	6.67	30.40	26.90	27.60	28.30
Wisconsin Energy Corp.	5.00	4.70	4.80	4.83	18.40	16.70	18.40	17.83
Xcel Energy Inc.	3.90	4.20	4.40	4.17	17.10	18.80	19.00	18.30
Median	**4.55**	**4.45**	**5.30**	**4.78**	**19.40**	**21.13**	**23.35**	**21.45**

[1/] Data from S&P Credit Stats.

Source: Standard & Poor's Debt Rating Reports except where noted.

HISTORIC EQUITY MARKET RISK PREMIUMS
(Arithmetic Averages)

Canada
(1947-2011)

Stock Return	Bond Total Return	Risk Premium
11.8	7.1	4.7

Stock Return	Bond Income Return	Risk Premium
11.8	6.7	5.0

United States
(1947-2011)

Stock Return	Bond Total Return	Risk Premium
12.3	6.6	5.7

Stock Return	Bond Income Return	Risk Premium
12.3	5.9	6.4

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*.

HISTORIC EQUITY MARKET RISK PREMIUMS
(Arithmetic Averages)

Canada
(1924-2011)

Stock Return	Bond Total Return	Risk Premium
11.4	6.6	4.8
Stock Return	Bond Income Return	Risk Premium
11.4	6.0	5.4

United States
(1926-2011)

Stock Return	Bond Total Return	Risk Premium
11.8	6.1	5.6
Stock Return	Bond Income Return	Risk Premium
11.8	5.2	6.6

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*.

FIVE-YEAR STANDARD DEVIATIONS OF MARKET RETURNS FOR 10 SECTOR INDICES OF S&P/TSX COMPOSITE
(Percentages)

Five Year Periods Ending:	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Average
S&P / TSX Composite	**3.57**	**4.68**	**4.84**	**5.40**	**5.87**	**5.83**	**4.97**	**4.59**	**4.04**	**3.24**	**2.86**	**4.35**	**4.88**	**4.88**	**4.95**	**4.60**
10 Sector Indices																
Consumer Discretionary	3.69	4.36	4.62	4.99	5.38	5.73	5.35	5.00	4.35	3.69	3.08	3.84	4.07	4.04	4.13	4.42
Consumer Staples	3.57	4.01	3.70	4.04	4.17	4.76	4.45	4.37	4.05	3.88	2.97	3.24	3.36	3.68	3.54	3.85
Energy	5.60	6.16	7.31	7.97	8.30	8.10	6.98	5.72	5.56	5.46	5.40	7.04	7.37	6.71	6.72	6.69
Financials	4.27	5.89	5.92	6.22	6.17	6.06	4.58	4.23	3.77	3.36	2.97	3.99	5.38	5.59	5.62	4.93
Health Care	6.62	7.73	8.19	9.38	9.00	9.39	8.93	8.68	6.98	6.57	5.45	4.92	5.38	5.89	7.47	7.37
Industrials	4.13	4.93	4.69	5.12	6.50	7.18	6.92	6.87	6.48	5.16	4.08	4.87	5.48	5.51	5.66	5.57
Information Technology	7.99	9.17	10.35	12.27	15.16	17.12	16.64	17.09	15.81	13.36	10.20	11.82	11.68	12.14	12.60	12.89
Materials	5.87	6.98	7.22	7.29	7.40	7.25	5.89	5.65	5.67	5.88	5.59	7.96	8.48	8.60	8.69	6.96
Telecommunication Services	3.66	5.82	7.37	7.87	8.46	8.71	7.54	5.74	4.97	4.64	4.18	5.08	5.07	4.93	4.59	5.91
Utilities	3.12	3.80	4.00	4.80	5.06	4.88	4.49	4.09	3.36	3.13	3.49	4.04	4.32	4.30	4.09	4.07
Mean	**4.85**	**5.89**	**6.34**	**7.00**	**7.56**	**7.92**	**7.18**	**6.75**	**6.10**	**5.51**	**4.74**	**5.68**	**6.06**	**6.14**	**6.31**	**6.27**
Median	**4.20**	**5.85**	**6.57**	**6.76**	**6.95**	**7.21**	**6.41**	**5.68**	**5.27**	**4.90**	**4.13**	**4.90**	**5.38**	**5.55**	**5.64**	**5.69**

Ratios of Standard Deviations

S&P/TSX Utilities Index as a Percent of:																
10 Sector Indices (Mean)	**0.64**	**0.65**	**0.63**	**0.69**	**0.67**	**0.62**	**0.63**	**0.61**	**0.55**	**0.57**	**0.74**	**0.71**	**0.71**	**0.70**	**0.65**	**0.65**
10 Sector Indices (Median)	**0.74**	**0.65**	**0.61**	**0.71**	**0.73**	**0.68**	**0.70**	**0.72**	**0.64**	**0.64**	**0.85**	**0.82**	**0.80**	**0.77**	**0.73**	**0.72**

Source: *TSX Review*

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	Consumer Discretionary (1)	Consumer Staples (2)	Energy (3)	Financials (4)	Health Care (5)	Industrials (6)	Information Technology (7)	Materials (8)	Telecommunication Services (9)	Utilities (10)
1997	0.82	0.62	0.97	0.94	0.60	0.97	1.57	1.32	0.64	0.53
1998	0.80	0.60	0.85	1.12	1.01	0.93	1.41	1.12	0.92	0.55
1999	0.73	0.44	0.90	1.00	1.00	0.78	1.55	1.04	1.11	0.30
2000	0.69	0.23	0.66	0.78	1.09	0.72	1.78	0.74	0.92	0.14
2001	0.68	0.10	0.49	0.66	0.98	0.82	2.13	0.60	0.94	-0.03
2002	0.73	0.08	0.43	0.66	0.99	0.86	2.28	0.57	0.93	-0.06
2003	0.74	-0.08	0.26	0.38	0.85	0.91	2.74	0.43	0.83	-0.25
2004	0.80	-0.07	0.17	0.39	0.82	1.05	2.87	0.41	0.58	-0.13
2005	0.83	0.07	0.48	0.56	0.72	1.13	2.68	0.77	0.74	0.00
2006	0.86	0.37	1.03	0.68	0.85	1.06	2.07	1.32	0.52	0.25
2007	0.73	0.54	1.44	0.51	0.54	0.96	1.12	1.45	0.62	0.46
2008	0.59	0.32	1.43	0.61	0.48	0.81	1.43	1.30	0.55	0.49
2009	0.56	0.28	1.35	0.80	0.41	0.83	1.22	1.24	0.47	0.41
2010	0.55	0.33	1.24	0.85	0.39	0.87	1.37	1.22	0.46	0.42
2011	0.52	0.31	1.25	0.85	0.37	0.89	1.49	1.19	0.45	0.43

Source: *TSX Review*

TSE 300 SUB-INDEX COMPOUND RETURNS AND BETAS
(1956-2003)

	Sub-Index Compound Returns [1/]						Sub-Index Betas					
	56-03	56-97	64-73	74-83	84-93	94-03	56-03	56-97	64-73	74-83	84-93	94-03
Metals/Minerals	7.8	7.6	7.5	11.2	6.8	7.2	1.15	1.23	1.14	1.22	1.37	0.87
Gold/Precious Metals	9.5	10.4	16.2	16.0	11.0	-2.7	0.85	0.96	0.36	1.31	1.24	0.64
Oil and Gas	9.5	8.4	14.6	11.9	4.5	15.3	1.06	1.20	1.25	1.40	0.98	0.52
Paper/Forest Products	7.1	7.4	4.8	11.8	10.3	2.6	1.02	1.07	1.15	1.00	1.27	0.85
Consumer Products	11.3	11.9	10.2	13.8	11.2	9.6	0.83	0.86	0.84	0.90	0.89	0.73
Industrial Products	7.2	9.6	8.3	10.9	6.0	1.1	1.17	1.02	1.11	0.87	1.08	1.69
Real Estate [2/]	5.3	5.5	0.7	16.7	-2.3	1.3	1.00	1.18	1.21	1.28	1.06	0.46
Transportation/Environmental	10.1	11.4	12.7	18.4	3.0	8.8	0.94	1.04	0.94	1.08	1.22	0.62
Pipelines	11.7	12.1	5.2	13.8	13.7	13.1	0.68	0.85	0.80	0.92	0.76	0.02
Utilities	11.0	10.7	3.3	17.8	11.0	16.3	0.54	0.48	0.50	0.47	0.40	0.79
Communications/Media	13.5	15.0	19.1	15.3	12.9	7.5	0.77	0.77	0.96	0.69	0.95	0.80
Merchandising	10.1	10.7	10.6	12.2	8.7	7.2	0.78	0.86	0.93	0.84	0.83	0.46
Finance	12.4	12.8	12.0	11.7	11.6	17.9	0.83	0.85	0.95	0.71	0.93	0.77
Conglomerates	10.8	10.8	12.8	15.2	9.5	13.9	0.94	1.03	1.26	0.97	1.20	0.68
Adjusted R Square [3/]							**47%**	**44%**	**1%**	**1%**	**11%**	**9%**
Beta [4/]							**-0.088**	**-0.082**	**-0.020**	**-0.008**	**-0.056**	**-0.053**

[1/] Annualized rate of return at which capital has compounded over time.
[2/] Data only available starting July 1961
[3/] Represents percentage of variation in sub-index returns explained by the sub-index betas.
[4/] Represents relationship between sub-index returns and sub-index betas.

Source: *TSX Review*

S&P/TSX COMPOSITE SECTOR COMPOUND RETURNS AND BETAS
(1988-2011)

	Sector Compound Returns [1/]			Sector Betas		
	88-11	**88-97**	**02-11**	**88-11**	**88-97**	**02-11**
Consumer Discretionary	5.9	10.2	1.3	0.72	0.90	0.63
Consumer Staples	11.2	12.7	7.5	0.34	0.73	0.34
Energy	10.2	8.4	13.3	0.82	0.76	1.19
Financials	12.4	18.3	8.4	0.80	1.04	0.80
Health Care	6.4	15.5	-0.9	0.73	0.81	0.50
Industrials	6.3	8.3	4.7	0.94	1.13	0.92
Information Technology	2.2	21.8	-19.8	1.72	1.21	1.68
Materials	6.6	3.4	13.6	0.99	1.26	1.23
Telecommunication Services	13.0	15.4	4.4	0.66	0.58	0.46
Utilities	10.4	11.5	12.3	0.29	0.62	0.38
Adjusted R Square [2/]				**52%**	**1%**	**18%**
Beta [3/]				**-0.063**	**-0.017**	**-0.094**

[1/] Data only available starting December 1987. Annualized rate of return at which capital has compounded over time.
[2/] Represents percentage of variation in sector returns explained by the sector betas.
[3/] Represents relationship between sector returns and sector betas.

Source: *TSX Review*

MONTHLY BETAS FOR REGULATED CANADIAN UTILITIES

"Raw" Monthly Price Betas
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Canadian Utilities Limited	0.46	0.54	0.48	0.55	0.63	0.62	0.54	0.38	0.27	0.19	0.05	0.03	0.20	0.32	0.58	0.19	0.06	0.06	0.03
Emera Inc.	na	na	na	0.52	0.40	0.55	0.41	0.27	0.20	0.15	-0.05	0.01	0.07	0.12	0.24	0.17	0.16	0.21	0.21
Enbridge Inc.	0.35	0.53	0.46	0.44	0.43	0.48	0.26	0.07	-0.10	-0.18	-0.37	-0.32	-0.19	0.22	0.54	0.30	0.30	0.32	0.30
Fortis Inc.	0.35	0.44	0.51	0.37	0.30	0.49	0.33	0.23	0.14	0.13	-0.06	0.01	0.21	0.48	0.65	0.21	0.20	0.16	0.14
TransCanada Corporation	0.40	0.57	0.56	0.52	0.36	0.55	0.21	0.15	-0.08	-0.09	-0.38	-0.16	-0.15	0.34	0.52	0.38	0.39	0.39	0.37
Mean	**0.39**	**0.52**	**0.50**	**0.48**	**0.42**	**0.54**	**0.35**	**0.22**	**0.08**	**0.04**	**-0.16**	**-0.08**	**0.03**	**0.30**	**0.51**	**0.25**	**0.22**	**0.23**	**0.21**
Median	**0.38**	**0.54**	**0.50**	**0.52**	**0.40**	**0.55**	**0.33**	**0.23**	**0.14**	**0.13**	**-0.06**	**0.01**	**0.07**	**0.32**	**0.54**	**0.21**	**0.20**	**0.21**	**0.21**
TSE Gas/Electric Index	0.42	0.48	0.52	0.52	0.46	0.55	0.38	0.21	0.17	0.14	NA	NA	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.55	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13	0.00	0.25	0.46	0.49	0.41	0.42	0.43

Adjusted Betas [1/]
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Canadian Utilities Limited	0.64	0.69	0.65	0.70	0.75	0.75	0.69	0.58	0.51	0.46	0.37	0.35	0.47	0.54	0.72	0.45	0.37	0.37	0.35
Emera Inc.	NA	NA	NA	0.68	0.60	0.70	0.60	0.51	0.46	0.43	0.29	0.33	0.38	0.41	0.49	0.44	0.44	0.47	0.47
Enbridge Inc.	0.56	0.69	0.64	0.62	0.62	0.65	0.50	0.38	0.26	0.21	0.08	0.12	0.21	0.48	0.69	0.53	0.53	0.54	0.53
Fortis Inc.	0.57	0.62	0.67	0.58	0.53	0.66	0.55	0.48	0.42	0.41	0.29	0.34	0.47	0.65	0.77	0.47	0.46	0.44	0.42
TransCanada Corporation	0.60	0.71	0.71	0.68	0.57	0.70	0.47	0.43	0.28	0.27	0.08	0.22	0.23	0.56	0.68	0.58	0.59	0.59	0.58
Mean	**0.59**	**0.68**	**0.67**	**0.65**	**0.61**	**0.69**	**0.56**	**0.48**	**0.39**	**0.36**	**0.22**	**0.27**	**0.35**	**0.53**	**0.67**	**0.50**	**0.48**	**0.48**	**0.47**
Median	**0.58**	**0.69**	**0.66**	**0.68**	**0.60**	**0.70**	**0.55**	**0.48**	**0.42**	**0.41**	**0.29**	**0.33**	**0.38**	**0.54**	**0.69**	**0.47**	**0.46**	**0.47**	**0.47**
TSE Gas/Electric Index	0.61	0.65	0.68	0.68	0.64	0.70	0.59	0.47	0.44	0.42	NA	NA	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.70	0.76	0.78	0.77	0.69	0.70	0.53	0.42	0.31	0.29	0.16	0.24	0.33	0.50	0.64	0.66	0.60	0.61	0.62

[1/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight* and *TSX Review*.

MONTHLY BETAS AND R^2s FOR REGULATED CANADIAN UTILITIES

Beta Ending	Canadian Utilities Limited		Emera Inc.		Enbridge Inc.		Fortis Inc.		TransCanada Corp.		S&P/TSX Utilities	
	Beta	R^2	Beta	R^2	Beta	R^2	Beta	R^2	Beta	R^2	Beta	R^2
2004	0.03	0.1%	0.01	0.0%	-0.32	7.0%	0.01	0.0%	-0.16	1.6%	-0.13	2.3%
2005	0.20	4.2%	0.07	0.5%	-0.19	2.8%	0.21	3.0%	-0.15	2.5%	0.00	0.0%
2006	0.32	4.9%	0.12	1.1%	0.22	4.2%	0.48	9.0%	0.34	10.0%	0.25	6.8%
2007	0.58	10.1%	0.24	3.2%	0.54	12.5%	0.65	11.8%	0.52	14.8%	0.46	14.3%
2008	0.19	1.9%	0.17	3.5%	0.30	7.8%	0.21	2.8%	0.38	16.4%	0.49	28.1%
2009	0.06	0.2%	0.16	3.3%	0.30	10.0%	0.20	2.9%	0.39	19.7%	0.41	21.5%
2010	0.06	0.2%	0.21	4.9%	0.32	11.2%	0.16	2.3%	0.39	19.1%	0.42	22.3%
2011	0.03	0.1%	0.21	5.4%	0.30	10.3%	0.14	2.4%	0.37	17.7%	0.43	27.1%

Source: Standard and Poor's *Research Insight*

WEEKLY BETAS FOR REGULATED CANADIAN UTILITIES

	"Raw" Weekly Price Betas Five Year Period Ending:							
COMPANY	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Canadian Utilities Limited	0.14	0.25	0.32	0.50	0.42	0.40	0.39	0.38
Emera Inc.	0.19	0.03	0.11	0.20	0.32	0.35	0.40	0.43
Enbridge Inc.	0.01	0.21	0.47	0.64	0.58	0.52	0.49	0.49
Fortis Inc.	-0.06	0.21	0.26	0.38	0.50	0.46	0.50	0.53
TransCanada Corporation	-0.02	0.14	0.35	0.48	0.45	0.44	0.44	0.44
Mean	**0.05**	**0.17**	**0.30**	**0.44**	**0.46**	**0.43**	**0.44**	**0.45**
Median	**0.01**	**0.21**	**0.32**	**0.48**	**0.45**	**0.44**	**0.44**	**0.44**
S&P/TSX Utilities	0.04	0.16	0.31	0.42	0.53	0.53	0.55	0.56

	Adjusted Betas [1/] Five Year Period Ending:							
COMPANY	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Canadian Utilities Limited	0.43	0.49	0.55	0.66	0.61	0.60	0.59	0.59
Emera Inc.	0.46	0.35	0.40	0.47	0.54	0.56	0.59	0.62
Enbridge Inc.	0.34	0.47	0.65	0.76	0.72	0.68	0.66	0.66
Fortis Inc.	0.29	0.47	0.50	0.59	0.67	0.64	0.66	0.68
TransCanada Corporation	0.31	0.42	0.57	0.65	0.63	0.62	0.63	0.62
Mean	**0.37**	**0.44**	**0.53**	**0.63**	**0.64**	**0.62**	**0.63**	**0.63**
Median	**0.34**	**0.47**	**0.55**	**0.65**	**0.63**	**0.62**	**0.63**	**0.62**
S&P/TSX Utilities	0.36	0.44	0.53	0.61	0.69	0.69	0.70	0.70

[1/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight* and *TSX Review*.

MONTHLY BETAS FOR SAMPLE OF U.S. UTILITIES

"Raw" Monthly Price Betas
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
AGL Resources Inc.	0.33	0.40	0.39	0.45	0.62	0.60	0.45	0.29	0.29	0.24	0.21	0.30	0.37	0.36	0.50	0.31	0.40	0.46	0.45
Alliant Energy Corp.	0.46	0.55	0.61	0.46	0.26	0.18	0.08	0.09	-0.02	0.10	0.24	0.34	0.40	0.80	0.72	0.59	0.57	0.53	0.53
Atmos Energy Corp.	0.32	0.32	0.50	0.76	0.08	0.16	0.19	0.00	-0.17	-0.02	-0.03	0.05	0.18	0.41	0.85	0.51	0.50	0.52	0.52
Consolidated Edison	0.57	0.55	0.53	0.59	0.66	0.32	0.18	0.09	-0.04	-0.16	-0.14	-0.05	0.00	0.14	0.39	0.25	0.29	0.31	0.26
Integrys Energy Group Inc.	0.34	0.31	0.38	0.25	0.29	0.16	0.10	0.01	-0.03	-0.01	0.06	0.15	0.17	0.37	0.56	0.48	0.91	0.89	0.87
Northwest Natural Gas	0.21	0.19	0.19	0.14	0.38	0.46	0.18	0.11	0.06	-0.11	-0.19	0.01	0.04	0.14	0.74	0.36	0.25	0.31	0.31
Piedmont Natural Gas	0.35	0.43	0.39	0.27	0.32	0.51	0.28	0.13	0.15	0.09	-0.03	0.13	0.28	0.35	0.58	0.06	0.19	0.23	0.31
Southern Company	0.51	0.47	0.39	0.53	0.42	0.15	0.11	-0.05	-0.36	-0.45	-0.47	-0.47	-0.49	-0.06	0.34	0.37	0.34	0.35	0.30
Vectren Corp.	0.22	0.23	0.23	0.64	0.57	0.34	0.16	0.24	0.20	0.23	0.35	0.46	0.32	0.49	0.56	0.25	0.37	0.42	0.41
WGL Holdings Inc.	0.29	0.36	0.39	0.75	0.62	0.47	0.28	0.25	0.19	0.14	0.11	0.22	0.21	0.27	0.69	0.24	0.17	0.25	0.28
Wisconsin Energy Corp.	0.47	0.53	0.52	0.58	0.43	0.31	0.14	0.11	-0.02	-0.10	-0.09	0.06	0.02	0.18	0.56	0.45	0.39	0.37	0.34
Xcel Energy Inc.	0.63	0.62	0.37	0.60	0.50	0.34	0.27	0.19	-0.01	0.41	0.56	0.70	0.80	1.48	0.60	0.56	0.46	0.44	0.39
Mean	**0.39**	**0.41**	**0.41**	**0.50**	**0.43**	**0.33**	**0.20**	**0.12**	**0.02**	**0.03**	**0.05**	**0.16**	**0.19**	**0.41**	**0.59**	**0.37**	**0.40**	**0.42**	**0.41**
Median	**0.34**	**0.41**	**0.39**	**0.56**	**0.43**	**0.33**	**0.18**	**0.11**	**-0.01**	**0.04**	**0.01**	**0.14**	**0.19**	**0.35**	**0.57**	**0.37**	**0.38**	**0.40**	**0.37**

Adjusted Betas [1/]
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
AGL Resources Inc.	0.55	0.60	0.59	0.63	0.74	0.73	0.63	0.52	0.53	0.49	0.47	0.53	0.58	0.57	0.66	0.54	0.60	0.64	0.63
Alliant Energy Corp.	0.64	0.70	0.74	0.64	0.50	0.45	0.38	0.39	0.31	0.40	0.49	0.56	0.60	0.87	0.81	0.73	0.71	0.68	0.68
Atmos Energy Corp.	0.55	0.54	0.66	0.84	0.38	0.44	0.46	0.33	0.22	0.32	0.31	0.36	0.45	0.61	0.90	0.67	0.66	0.68	0.68
Consolidated Edison	0.71	0.70	0.68	0.73	0.77	0.54	0.45	0.39	0.30	0.22	0.24	0.30	0.33	0.43	0.59	0.50	0.53	0.54	0.51
Integrys Energy Group Inc.	0.56	0.54	0.59	0.50	0.52	0.44	0.40	0.34	0.31	0.32	0.37	0.43	0.45	0.58	0.71	0.65	0.94	0.93	0.91
Northwest Natural Gas	0.47	0.46	0.46	0.42	0.58	0.64	0.45	0.41	0.37	0.26	0.20	0.33	0.36	0.43	0.83	0.57	0.50	0.54	0.54
Piedmont Natural Gas	0.56	0.62	0.59	0.51	0.54	0.67	0.52	0.42	0.43	0.39	0.31	0.42	0.52	0.57	0.72	0.37	0.46	0.49	0.54
Southern Company	0.67	0.65	0.59	0.69	0.61	0.43	0.40	0.30	0.09	0.03	0.02	0.01	0.00	0.29	0.55	0.58	0.56	0.57	0.53
Vectren Corp.	0.48	0.48	0.48	0.76	0.71	0.56	0.43	0.49	0.46	0.48	0.56	0.64	0.55	0.66	0.71	0.49	0.58	0.61	0.61
WGL Holdings Inc.	0.52	0.57	0.59	0.83	0.75	0.64	0.52	0.50	0.46	0.42	0.41	0.47	0.47	0.51	0.79	0.49	0.44	0.50	0.52
Wisconsin Energy Corp.	0.64	0.68	0.68	0.72	0.62	0.54	0.42	0.40	0.32	0.26	0.27	0.37	0.34	0.45	0.71	0.63	0.59	0.58	0.56
Xcel Energy Inc.	0.75	0.75	0.58	0.73	0.67	0.56	0.51	0.46	0.32	0.60	0.70	0.80	0.87	1.32	0.73	0.70	0.64	0.62	0.59
Mean	**0.59**	**0.61**	**0.60**	**0.67**	**0.62**	**0.55**	**0.47**	**0.41**	**0.34**	**0.35**	**0.36**	**0.43**	**0.46**	**0.61**	**0.73**	**0.58**	**0.60**	**0.61**	**0.61**
Median	**0.56**	**0.61**	**0.59**	**0.70**	**0.62**	**0.55**	**0.45**	**0.40**	**0.32**	**0.36**	**0.34**	**0.42**	**0.46**	**0.57**	**0.71**	**0.58**	**0.59**	**0.60**	**0.58**

[1/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight*

WEEKLY BETAS FOR SAMPLE OF U.S. UTILITIES

"Raw" Weekly Price Betas
Five Year Period Ending:

COMPANY	2004	2005	2006	2007	2008	2009	2010	2011
AGL Resources Inc.	0.44	0.56	0.63	0.74	0.70	0.70	0.68	0.68
Alliant Energy Corp.	0.38	0.52	0.72	0.70	0.72	0.74	0.78	0.75
Atmos Energy Corp.	0.50	0.50	0.59	0.70	0.66	0.64	0.67	0.65
Consolidated Edison	0.25	0.29	0.39	0.48	0.50	0.50	0.51	0.47
Integrys Energy Group Inc.	0.29	0.42	0.50	0.63	0.64	0.82	0.83	0.80
Northwest Natural Gas	0.34	0.46	0.54	0.83	0.54	0.51	0.54	0.53
Piedmont Natural Gas	0.42	0.52	0.61	0.77	0.61	0.60	0.61	0.63
Southern Company	0.05	0.19	0.29	0.42	0.42	0.41	0.41	0.38
Vectren Corp.	0.73	0.55	0.74	0.79	0.60	0.64	0.64	0.63
WGL Holdings Inc.	0.43	0.52	0.63	0.78	0.68	0.62	0.61	0.61
Wisconsin Energy Corp.	0.36	0.41	0.48	0.67	0.58	0.52	0.52	0.49
Xcel Energy Inc.	0.54	0.68	0.81	0.60	0.55	0.53	0.53	0.51
Mean	**0.39**	**0.47**	**0.58**	**0.68**	**0.60**	**0.60**	**0.61**	**0.59**
Median	**0.40**	**0.51**	**0.60**	**0.70**	**0.61**	**0.61**	**0.61**	**0.62**

Adjusted Betas [1/]
Five Year Period Ending:

COMPANY	2004	2005	2006	2007	2008	2009	2010	2011
AGL Resources Inc.	0.62	0.71	0.75	0.82	0.80	0.80	0.79	0.79
Alliant Energy Corp.	0.58	0.68	0.81	0.80	0.81	0.83	0.85	0.83
Atmos Energy Corp.	0.66	0.66	0.72	0.80	0.78	0.76	0.78	0.77
Consolidated Edison	0.50	0.53	0.59	0.65	0.66	0.66	0.67	0.64
Integrys Energy Group Inc.	0.53	0.61	0.66	0.75	0.76	0.88	0.89	0.86
Northwest Natural Gas	0.56	0.64	0.69	0.89	0.69	0.67	0.69	0.68
Piedmont Natural Gas	0.61	0.68	0.74	0.85	0.74	0.73	0.74	0.75
Southern Company	0.37	0.46	0.52	0.61	0.61	0.60	0.60	0.59
Vectren Corp.	0.82	0.70	0.83	0.86	0.73	0.76	0.76	0.75
WGL Holdings Inc.	0.62	0.68	0.75	0.85	0.78	0.74	0.74	0.74
Wisconsin Energy Corp.	0.57	0.60	0.65	0.78	0.72	0.68	0.68	0.66
Xcel Energy Inc.	0.69	0.79	0.87	0.73	0.70	0.68	0.69	0.67
Mean	**0.59**	**0.64**	**0.72**	**0.78**	**0.73**	**0.73**	**0.74**	**0.73**
Median	**0.60**	**0.67**	**0.73**	**0.80**	**0.74**	**0.74**	**0.74**	**0.74**

[1/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: www.yahoo.com

HISTORICAL VALUE LINE BETAS FOR SAMPLE OF U.S. UTILITIES

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
AGL Resources Inc.	0.75	0.75	0.65	0.65	0.60	0.60	0.75	0.75	0.80	0.90	0.95	0.85	0.75	0.75	0.75	0.75
Alliant Energy Corp.	0.60	0.55	nmf	nmf	0.55	0.55	0.65	0.70	0.80	0.85	0.95	0.80	0.70	0.70	0.70	0.75
Atmos Energy Corp.	0.65	0.55	0.55	0.55	0.55	0.55	0.60	0.65	0.70	0.70	0.80	0.85	0.65	0.65	0.65	0.70
Consolidated Edison	0.75	0.75	0.60	0.50	0.55	0.50	0.55	0.60	0.60	0.60	0.75	0.75	0.65	0.65	0.65	0.60
Integrys Energy Group Inc.	0.65	0.65	0.65	0.50	0.55	0.55	0.60	0.70	0.75	0.75	0.85	0.80	0.70	0.95	0.90	0.90
Northwest Natural Gas	0.45	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.65	0.70	0.75	0.90	0.60	0.60	0.60	0.60
Piedmont Natural Gas	0.65	0.60	0.55	0.55	0.60	0.60	0.70	0.70	0.75	0.75	0.80	0.85	0.70	0.65	0.65	0.70
Southern Company [1/]	0.70	0.70	0.50	0.45	0.50	nmf	nmf	0.60	0.65	0.65	0.70	0.70	0.55	0.55	0.55	0.55
Vectren Corp.	0.70	0.75	0.75	0.55	nmf	nmf	0.70	0.75	0.75	0.80	0.90	0.90	0.85	0.75	0.70	0.70
WGL Holdings Inc.	0.70	0.75	0.60	0.60	0.60	0.60	0.65	0.70	0.75	0.80	0.85	0.85	0.75	0.65	0.65	0.65
Wisconsin Energy Corp.	0.70	0.70	0.65	0.45	0.50	0.50	0.55	0.60	0.70	0.70	0.80	0.85	0.65	0.65	0.65	0.65
Xcel Energy Inc.	na	na	na	na	nmf	nmf	0.60	0.70	0.80	0.80	0.90	1.05	0.75	0.65	0.65	0.65
Mean	**0.66**	**0.67**	**0.61**	**0.54**	**0.56**	**0.56**	**0.63**	**0.67**	**0.73**	**0.75**	**0.83**	**0.85**	**0.69**	**0.68**	**0.68**	**0.68**
Median	**0.70**	**0.70**	**0.60**	**0.55**	**0.55**	**0.55**	**0.60**	**0.70**	**0.75**	**0.75**	**0.83**	**0.85**	**0.70**	**0.65**	**0.65**	**0.68**

1/ 1996 number is from 1st quarter 1997.

Source: Value Line fourth quarter issues

INDIVIDUAL COMPANY RISK DATA FOR SAMPLE OF U.S. UTILITIES

	Value Line									S & P		Moody's
	Safety	Forecast Common Equity Ratio 2015-2017	Forecast Return On Average Common Equity 2015-2017	Dividend Payout Forecast 2015-2017	2012Q2 Beta	"Raw" Weekly Betas[1/]	Adjusted Weekly Betas	Common Equity Ratio 2011Q4 Trailing Four Quarters	2009-2011 Average Earned Returns	Business Risk Profile	Debt Rating	Debt Rating[2/]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
AGL Resources Inc.	1	57.0%	12.3%	48.8%	0.75	0.64	0.76	43.4%	10.9%	Excellent	BBB+	Baa1
Alliant Energy Corp.	2	49.5%	11.4%	61.1%	0.75	0.68	0.78	50.1%	8.1%	Excellent	BBB+	Baa1
Atmos Energy Corp.	2	51.0%	7.9%	54.8%	0.70	0.61	0.74	49.7%	9.3%	Excellent	BBB+	Baa1
Consolidated Edison	1	52.5%	9.3%	62.0%	0.60	0.41	0.61	50.8%	9.1%	Excellent	A-	Baa1
Integrys Energy Group Inc.	2	56.0%	9.8%	65.9%	0.90	0.72	0.81	55.2%	4.3%	Excellent	A-	Baa1
Northwest Natural Gas	1	63.0%	10.9%	53.9%	0.60	0.47	0.65	47.0%	10.5%	Excellent	A+	A3
Piedmont Natural Gas	2	50.0%	13.2%	71.1%	0.70	0.57	0.72	51.4%	13.4%	Excellent	A	A3
Southern Company	1	45.5%	12.6%	69.2%	0.55	0.32	0.54	44.3%	12.5%	Excellent	A	Baa1
Vectren Corp.	2	48.0%	12.2%	64.0%	0.70	0.59	0.72	45.2%	9.6%	Excellent	A-	A3
WGL Holdings Inc.	1	70.5%	10.0%	62.5%	0.65	0.55	0.70	62.1%	10.3%	Excellent	A+	A2
Wisconsin Energy Corp.	1	46.5%	13.9%	65.5%	0.65	0.44	0.63	47.8%	12.3%	Excellent	A-	A3
Xcel Energy Inc.	2	50.0%	10.6%	60.0%	0.65	0.45	0.63	45.3%	9.8%	Excellent	A-	Baa1
Mean	**1.5**	**53.3%**	**11.2%**	**61.6%**	**0.68**	**0.54**	**0.69**	**49.3%**	**10.0%**	**Excellent**	**A-**	**Baa1**
Median	**1.5**	**50.5%**	**11.1%**	**62.2%**	**0.68**	**0.56**	**0.71**	**48.7%**	**10.1%**	**Excellent**	**A-**	**Baa1**

[1/] "Raw" betas calculated using weekly price changes against the NYSE Composite (260 weeks ending May 21, 2012).
[2/] Rating for Vectren Corp. is for Vectren Utility Holdings. Rating for WGL Holdings is Washington Gas Light.

Source: www.Moodys.com; Standard and Poor's, *Issuer Ranking: U.S. Regulated Utilities, Strongest To Weakest* (April 20, 2012); Standard and Poor's Research Insight; Value Line (February, March, and May 2012); *Value Line Index* , May 11, 2012; and www.yahoo.com.

EQUITY RETURN AWARDS AND COMMON EQUITY RATIOS ADOPTED FOR THE SAMPLE OF U.S. UTILITIES
2009-2012

Parent	Subsidiary (1)	Service (2)	State (3)	Decision Date (4)	Allowed ROE (5)	Allowed Common Equity Ratio (6)
AGL Resources Inc.	Atlanta Gas Light Co.	Gas	GA	11/3/2010	10.75	51.00
	Northern Illinois Gas Co.	Gas	IL	3/25/2009	10.17	51.07
	Pivotal Utility Holdings Inc.	Gas	NJ	12/17/2009	10.30	47.89
	Chattanooga Gas Co.	Gas	TN	5/24/2010	10.05	46.06
	Virginia Natural Gas Inc.	Gas	VA	12/20/2011	10.00	45.36
Alliant Energy Corp.	Interstate P&L	Electric	IA	12/15/2010	10.44	44.24
	Interstate P&L	Electric	MN	8/12/2011	10.35	47.74
	Wisconsin P&L	Electric	WI	6/15/2012	10.40	49.31
	Wisconsin P&L	Gas	WI	6/15/2012	10.40	49.31
Atmos Energy Corp.	Atmos Energy Corp.	Gas	GA	3/31/2010	10.70	47.70
	Atmos Energy Corp.	Gas	TN	3/9/2009	10.30	48.12
	Atmos Energy Corp.	Gas	TX	1/26/2010	10.40	48.91
Consolidated Edison	Rockland Electric Co.	Electric	NJ	5/12/2010	10.30	49.85
	Consolidated Edison Co. of NY	Gas	NY	9/16/2010	9.60	48.00
	Consolidated Edison Co. of NY	Electric	NY	3/25/2010	10.15	48.00
	Orange & Rockland Utilities Inc.	Electric	NY	6/14/2012	9.40	48.00
	Orange & Rockland Utilities Inc.	Gas	NY	10/16/2009	10.40	48.00
Integrys Energy Group Inc.	North Shore Gas Co.	Gas	IL	1/10/2012	9.45	50.00
	Peoples Gas Light & Coke Co.	Gas	IL	1/10/2012	9.45	49.00
	Michigan Gas Utilities Corp.	Gas	MI	12/16/2009	10.75	47.27
	Upper Peninsula Power	Electric	MI	12/20/2011	10.20	54.90
	Minnesota Energy Resources	Gas	MN	5/24/2012	9.70	NA
	Wisconsin Public Service	Electric	WI	1/13/2011	10.30	51.65
	Wisconsin Public Service	Gas	WI	1/13/2011	10.30	51.65
Piedmont Natural Gas Co.	Piedmont Natural Gas Co.	Gas	TN	1/23/2012	10.20	52.71
Southern Co.	Gulf Power Co.	Electric	FL	2/27/2012	10.25	46.26
	Georgia Power	Electric	GA	12/29/2010	11.15	51.67
Vectren Corp.	Southern Indiana G&E	Electric	IN	4/27/2011	10.40	49.93
WGL Holdings Inc.	Washington Gas Light Co.	Gas	MD	11/14/2011	9.60	57.88
	Washington Gas Light Co.	Gas	VA	4/21/2011	10.00	55.70
Wisconsin Energy Corp.	Wisconsin Electric Power	Electric	MI	6/26/2012	10.10	43.51
	Wisconsin Electric Power	Electric	WI	12/18/2009	10.40	53.02
	Wisconsin Electric Power	Gas	WI	12/18/2009	10.40	53.02
	Wisconsin Gas LLC	Gas	WI	12/18/2009	10.50	46.62
Xcel Energy Inc.	Public Service of CO	Electric	CO	4/26/2012	10.00	56.00
	Public Service of CO	Gas	CO	9/1/2011	10.10	56.00
	Northern States Power-MN	Electric	MN	3/29/2012	10.37	52.56
	Northern States Power-MN	Gas	MN	12/6/2010	10.09	52.46
	Northern States Power-MN	Electric	ND	2/29/2012	10.40	51.77
	Northern States Power-MN	Electric	SD	6/19/2012	9.25	53.04
	Southwestern Public Service	Electric	TX	3/25/2011	NA	NA [1/]
	Northern States Power-WI	Gas	WI	12/22/2011	10.40	52.59
	Northern States Power-WI	Electric	WI	12/22/2011	10.40	52.59

2009-2012:		
Mean	**10.20**	**50.25**
Median	**10.30**	**49.93**
2011-2012:		
Mean	**10.06**	**51.19**
Median	**10.20**	**51.65**

[1/] A 10% ROE and 51% equity ratio are to be used, per the settlement, solely for purposes of any Transmission Cost Recovery Factor filings before the next PUC rate case and for AFUDC purposes only.

Source: Regulatory Research Associates and various regulatory decisions.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES
CONSTANT GROWTH DCF MODEL
(Annual Averages of Monthly Data)

Year	Expected Dividend Yield[1/] (1)	I/B/E/S EPS Growth Forecast (2)	DCF Cost of Equity (3)	Long-Term Treasury Yield (4)	Equity Risk Premium (5)	Moody's Spread[2/] (6)
1998	5.0	4.3	9.3	5.5	3.8	1.5
1999	5.5	4.7	10.2	5.9	4.3	1.7
2000	6.1	5.0	11.1	5.9	5.2	2.4
2001	5.4	5.1	10.5	5.5	5.0	2.3
2002	5.3	5.7	10.9	5.4	5.5	1.9
2003	5.1	5.0	10.0	5.0	5.0	1.5
2004	4.7	4.4	9.1	5.1	4.0	1.0
2005	4.3	4.4	8.7	4.5	4.2	1.1
2006	4.5	4.7	9.2	4.9	4.3	1.2
2007	4.3	4.9	9.2	4.8	4.4	1.3
2008	4.8	5.4	10.3	4.2	6.0	2.3
2009	5.5	5.3	10.9	4.1	6.8	1.9
2010	4.9	5.0	9.9	4.2	5.7	1.2
2011	4.4	5.2	9.6	3.9	5.8	1.1
2012 Q1	4.3	4.7	9.0	3.1	5.9	1.2
Means for Long Treasury Yields:						
Below 4.0%	**4.8**	**5.2**	**9.9**	**3.4**	**6.5**	**1.8**
4.0-4.99%	**4.7**	**5.0**	**9.7**	**4.6**	**5.1**	**1.4**
Below 5.0%	**4.7**	**5.0**	**9.7**	**4.4**	**5.4**	**1.5**
5.0-5.99%	**5.2**	**4.9**	**10.1**	**5.5**	**4.6**	**1.7**
6.0% and above	**6.0**	**4.8**	**10.8**	**6.2**	**4.6**	**1.9**
Means: 1998 - 2012Q1	**5.0**	**4.9**	**9.9**	**4.9**	**5.0**	**1.6**

[1/] Dividend Yield adjusted for I/B/E/S growth (DY (1+g)).
[2/] Moody's Spread is the yield on Moody's long-term A rated Utility Index minus the 30-year Treasury yield.

Source: www.federalreserve.gov; I/B/E/S; www.Moodys.com; Standard & Poor's *Research Insight* ; and www.ustreas.gov.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES
CONSTANT GROWTH DCF MODEL

Regression Analysis Results 1998-2012Q1

EQUATION 1:

Equity Risk Premium = 8.76 - 0.77 (30-Year Treasury Yield)

t-statistics:

30-Year Treasury Yield = -9.41

R^2 = 34%

Equity Risk Premium at Long-Term Government Bond Yield of 4.00% = 5.7%

ROE at Long-Term Government Bond Yield of 4.00% = 9.7%

EQUATION 2:

Equity Risk Premium = 7.55 - 0.86 (30-Year Treasury Yield) + 1.06 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

30-Year Treasury Yield = -15.11

Spread = 13.42

R^2 = 68%

Equity Risk Premium at Long-term Government Bond Yield of 4.00% and Spread of 1.35% = 5.5%

ROE at Long-Term Government Bond Yield of 4.00% and Spread of 1.35% = 9.5%

EQUATION 3:

Equity Risk Premium = 6.86 - 0.53 (A-rated Utility Bond Yield)

t-statistics:

A-rated Utility Bond Yield = -10.12

R^2 = 38%

Equity Risk Premium at A-rated Utility Bond Yield of 5.35% = 4.0%

ROE at A-rated Utility Bond Yield of 5.35% = 9.4%

Note: t-statistics measure the statistical significance of an independent variable in explaining the dependent variable. The higher the t-value, the greater the confidence in the coefficient as a predictor. R^2 is the proportion of the variability in the dependent variable that is explained by the independent variable(s).

DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES
THREE STAGE MODEL

(Annual Averages of Monthly Data)

Year	Dividend Yield (1)	Implied Growth Rate (2)	DCF Cost of Equity[1/] (3)	Long-Term Treasury Yield (4)	Equity Risk Premium (5)	Moody's Spread[2/] (6)
1998	4.8	4.8	9.6	5.5	4.1	1.5
1999	5.3	4.9	10.2	5.9	4.2	1.7
2000	5.8	5.4	11.1	5.9	5.3	2.4
2001	5.1	5.6	10.7	5.5	5.3	2.3
2002	5.0	5.8	10.7	5.4	5.3	1.9
2003	4.8	5.6	10.4	5.0	5.4	1.5
2004	4.5	5.5	10.0	5.1	4.9	1.0
2005	4.1	5.4	9.5	4.5	5.0	1.1
2006	4.3	5.5	9.8	4.9	4.9	1.2
2007	4.1	5.3	9.4	4.8	4.6	1.3
2008	4.6	5.3	9.9	4.2	5.7	2.3
2009	5.2	5.4	10.6	4.1	6.5	1.9
2010	4.6	5.2	9.8	4.2	5.6	1.2
2011	4.2	5.2	9.4	3.9	5.5	1.1
2012 Q1	4.1	5.0	9.0	3.1	5.9	1.2
Means for Long Treasury Yields:						
Below 4.0%	**4.5**	**5.2**	**9.8**	**3.4**	**6.4**	**1.8**
4.0-4.99%	**4.5**	**5.4**	**9.9**	**4.6**	**5.3**	**1.4**
Below 5.0%	**4.5**	**5.3**	**9.8**	**4.4**	**5.5**	**1.5**
5.0-5.99%	**5.0**	**5.4**	**10.3**	**5.5**	**4.8**	**1.7**
6.0% and above	**5.7**	**5.0**	**10.7**	**6.2**	**4.5**	**1.9**
Means:						
1998 - 2012Q1	**4.7**	**5.3**	**10.1**	**4.9**	**5.2**	**1.6**

[1/] Internal Rate of Return: Stage 1 growth rate, I/B/E/S EPS growth forecast, applies for first 5 years; Stage 2 growth rate, average of Stage 1 and 3 growth rates, applies for years 6-10; Stage 3 growth, equal to the forecast nominal GDP growth rate, applies thereafter.
[2/] Moody's Spread is the yield on Moody's long-term A rated Utility Index minus the 30-year Treasury yield.

Source: www.federalreserve.gov; I/B/E/S; www.Moodys.com; Standard & Poor's *Research Insight* ; and www.ustreas.gov.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES
THREE STAGE MODEL

Regression Analysis Results 1998-2012 Q1

EQUATION 1:

Equity Risk Premium = 8.33 - 0.65 (30-Year Treasury Yield)

t-statistics:

30-Year Treasury Yield = -11.33

R^2 = 43%

Equity Risk Premium at Long-Term Government Bond Yield of 4.00% = 5.7%

ROE at Long-Term Government Bond Yield of 4.00% = 9.7%

EQUATION 2:

Equity Risk Premium = 7.56 - 0.71 (30-Year Treasury Yield) + 0.68 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

30-Year Treasury Yield = -16.35

Spread = 11.36

R^2 = 68%

Equity Risk Premium at Long-term Government Bond Yield of 4.00% and Spread of 1.35% = 5.6%

ROE at Long-Term Government Bond Yield of 4.00% and Spread of 1.35% = 9.6%

EQUATION 3:

Equity Risk Premium = 7.27 - 0.57 (A-rated Utility Bond Yield)

t-statistics:

A-rated Utility Bond Yield = -16.26

R^2 = 61%

Equity Risk Premium at A-rated Utility Bond Yield of 5.35% = 4.2%

ROE at A-rated Utility Bond Yield of 5.35% = 9.6%

Note: t-statistics measure the statistical significance of an independent variable in explaining the dependent variable. The higher the t-value, the greater the confidence in the coefficient as a predictor. R^2 is the proportion of the variability in the dependent variable that is explained by the independent variable(s).

APPROVED U.S. ELECTRIC AND GAS UTILITY ROES, BOND YIELDS AND SPREADS

	Approved Electric and Gas ROEs	Moody's A-Rated Utility Bond Yield	30-Year Treasury Yield	A-Rated Utility/ Treasury Yield Spread		Approved Electric and Gas ROEs	Moody's A-Rated Utility Bond Yield	30-Year Treasury Yield	A-Rated Utility/ Treasury Yield Spread
	(1)	(2)	(3)	(4)		(5)	(6)	(7)	(8)
1997 Q3		7.49	6.44	1.05	2005 Q1	10.54	5.72	4.70	1.02
1997 Q4		7.25	6.04	1.21	2005 Q2	10.25	5.43	4.36	1.07
1998 Q1	11.31	7.11	5.89	1.21	2005 Q3	10.63	5.49	4.39	1.10
1998 Q2	11.58	7.12	5.79	1.32	2005 Q4	10.55	5.82	4.63	1.18
1998 Q3	11.57	6.99	5.33	1.65	2006 Q1	10.55	5.92	4.70	1.22
1998 Q4	11.75	6.97	5.11	1.86	2006 Q2	10.64	6.41	5.19	1.22
1999 Q1	10.68	7.11	5.43	1.68	2006 Q3	10.18	6.09	4.91	1.18
1999 Q2	10.89	7.48	5.83	1.64	2006 Q4	10.31	5.82	4.70	1.13
1999 Q3	10.63	7.85	6.08	1.77	2007 Q1	10.36	5.92	4.82	1.10
1999 Q4	10.76	8.05	6.31	1.74	2007 Q2	10.23	6.08	4.98	1.10
2000 Q1	11.00	8.29	6.16	2.13	2007 Q3	10.03	6.19	4.86	1.33
2000 Q2	11.09	8.45	5.96	2.49	2007 Q4	10.42	6.05	4.53	1.52
2000 Q3	11.43	8.20	5.78	2.42	2008 Q1	10.42	6.16	4.35	1.81
2000 Q4	12.25	8.03	5.62	2.41	2008 Q2	10.46	6.30	4.58	1.72
2001 Q1	11.23	7.74	5.45	2.29	2008 Q3	10.48	6.58	4.44	2.14
2001 Q2	10.84	7.93	5.77	2.16	2008 Q4	10.34	7.13	3.50	3.63
2001 Q3	10.78	7.64	5.44	2.20	2009 Q1	10.27	6.44	3.62	2.82
2001 Q4	11.29	7.61	5.21	2.39	2009 Q2	10.35	6.35	4.24	2.11
2002 Q1	10.80	7.63	5.66	1.98	2009 Q3	10.23	5.54	4.17	1.37
2002 Q2	11.50	7.48	5.72	1.76	2009 Q4	10.41	5.65	4.35	1.30
2002 Q3	11.25	7.14	5.13	2.01	2010 Q1	10.51	5.80	4.59	1.20
2002 Q4	10.94	7.12	5.11	2.01	2010 Q2	10.04	5.46	4.22	1.24
2003 Q1	11.43	6.84	4.93	1.91	2010 Q3	10.17	4.96	3.73	1.23
2003 Q2	11.26	6.37	4.71	1.67	2010 Q4	10.21	5.31	4.15	1.16
2003 Q3	10.28	6.61	5.28	1.33	2011 Q1	10.26	5.56	4.53	1.03
2003 Q4	10.93	6.34	5.22	1.13	2011 Q2	10.04	5.37	4.33	1.04
2004 Q1	11.06	6.06	4.96	1.09	2011 Q3	9.92	4.74	3.54	1.20
2004 Q2	10.47	6.45	5.39	1.05	2011 Q4	10.22	4.35	3.04	1.31
2004 Q3	10.36	6.11	5.08	1.03	2012 Q1 [1/]	10.02	4.35	3.12	1.23
2004 Q4	10.80	5.95	4.93	1.01					

[1/] The first quarter 2012 average awarded ROE reported by RRA excluding ROEs granted for regulated generation investments.

Sources: www.federalreserve.gov; www.moodys.com; Regulatory Research Associates at www.snl.com; www.ustreas.gov

APPROVED ROES FOR U.S. ELECTRIC AND GAS UTILITIES
(ANNUAL AVERAGES OF MONTHLY DATA)

Regression Analysis Results 1998-2012Q1

EQUATION 1:

Equity Risk Premium = 8.00 - 0.46 (6 Months Lagged 30-Year Treasury Yield)

t-statistics:
6 Months Lagged 30-Year Treasury Yield = -7.17
R^2 = 48%

EQUATION 2:

Equity Risk Premium = 7.63 - 0.47 (6 Months Lagged 30-Year Treasury Yield) + 0.27 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
6 Months Lagged 30-Year Treasury Yield = -8.06
Spread = 3.53

R^2 = 58%

EQUATION 3:

Equity Risk Premium = 7.87 - 0.57 (6 Months Lagged Moody's A-Rated)

t-statistics:
6 Months Lagged Moody's A-Rated = -12.07

R^2 = 73%

HISTORIC UTILITY EQUITY RISK PREMIUMS
(Arithmetic Averages)

Canada
(1956-2011)

Utilities Index Return	Bond Total Return	Risk Premium
12.1	7.9	4.2

Utilities Index Return	Bond Income Return	Risk Premium
12.1	7.3	4.8

United States
(1947-2011)

S&P/Moody's Electric Index Return	Bond Total Return	Risk Premium
11.0	6.6	4.4

S&P/Moody's Electric Index Return	Bond Income Return	Risk Premium
11.0	5.9	5.1

S&P / Moody's Gas Distribution Index Return	Bond Total Return	Risk Premium
11.9	6.6	5.3

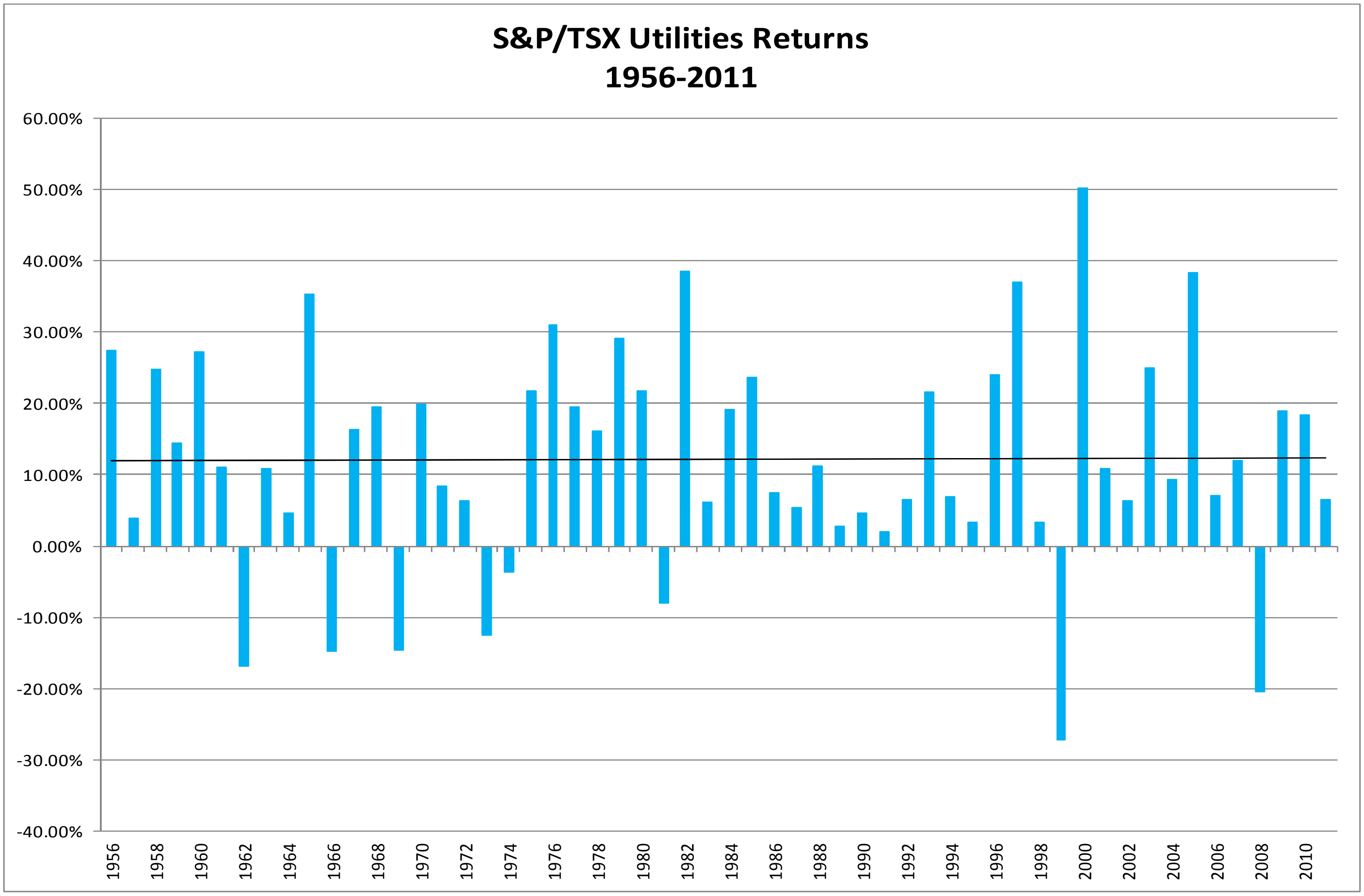
S&P / Moody's Gas Distribution Index Return	Bond Income Return	Risk Premium
11.9	5.9	6.0

Notes:
The Canadian Utilities Index is based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2011.

The S&P/Moody's Electric Index reflects S&P's Electric Index from 1947 to 1998 and Moody's Electric Index from 1999 to 2001. The 2002 to 2011 data were estimated using simple average of the prices and dividends for the utilities, and their successors, included in Moody's Electric Index as of the end of 2001.

The S&P/Moody's Gas Distribution Index reflects S&P's Natural Gas Distributors Index from 1947 to 1984, when S&P eliminated its gas distribution index. The 1985-2001 data are for Moody's Gas index. The index was terminated in July 2002. The 2002-2011 returns were estimated using simple averages of the prices and dividends for the utilities, and their successors, that were included in Moody's Gas Index as of the end of 2001.

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*; www.standardandpoors.com; *TSX Review.*


S&P/TSX Utilities Returns
1956-2011
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
1956
1958
1960
1962
1964
1966
1968
1970
1972
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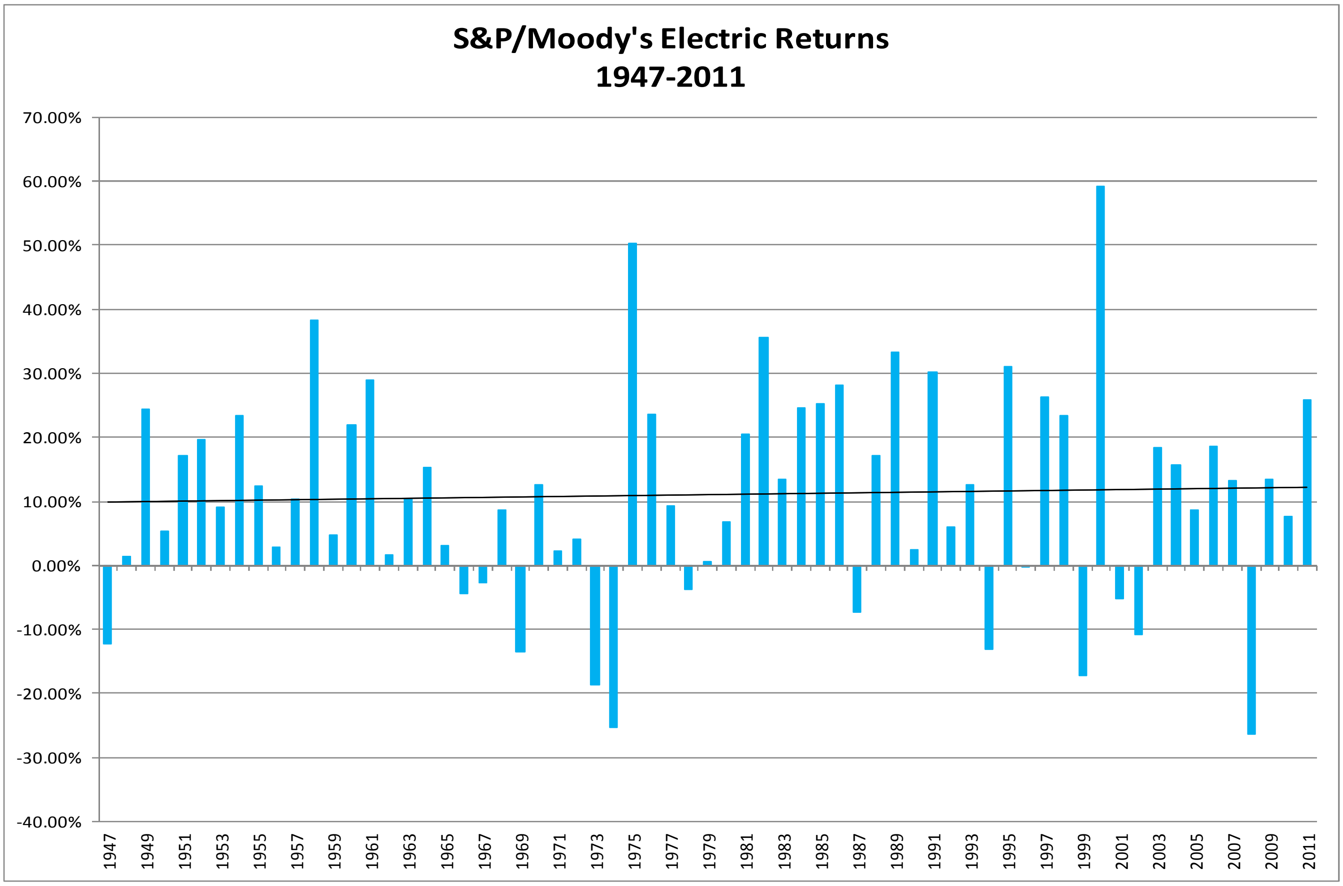
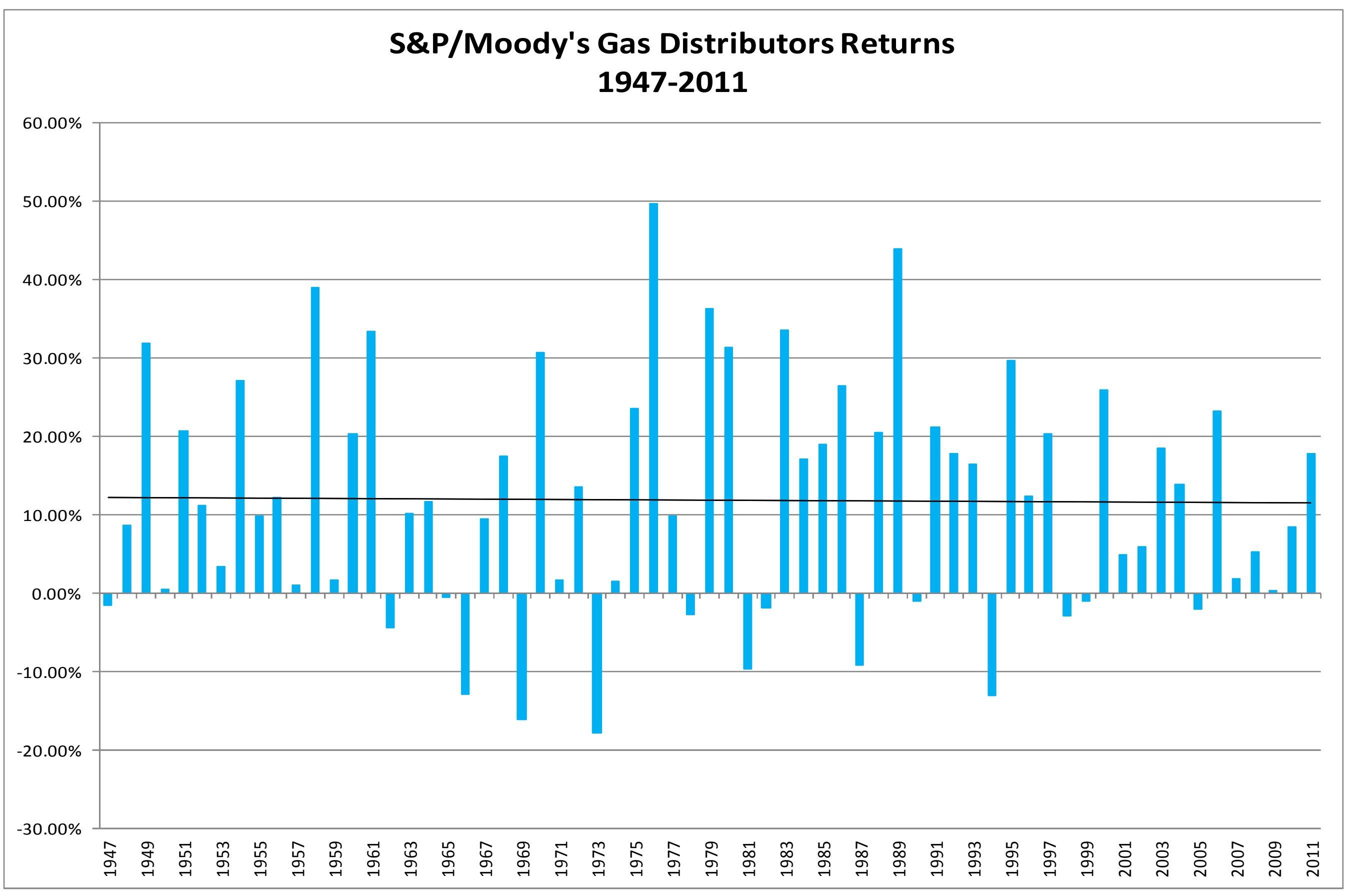

S&P/Moody's Electric Returns
1947-2011
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
1947 1949 1951 1953 1955 1957 1959 1961 1963 1965 1967 1969 1971 1973 1975 1977 1979 1981 1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005 2007 2009 2011


S&P/Moody's Gas Distributors Returns
1947-2011
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
1947 1949 1951 1953 1955 1957 1959 1961 1963 1965 1967 1969 1971 1973 1975 1977 1979 1981 1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005 2007 2009 2011

DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

				Analyst Forecast Long-Term Growth Rates					
Company	Annualized Last Paid Dividend	Average Daily Close Prices 3/16-6/15/2012	Expected Dividend Yield [1/]	Bloomberg	Reuters	Value Line	Zacks	Average of All EPS Estimates	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
AGL Resources Inc.	1.84	38.25	5.0	4.0	4.4	5.5	4.3	4.6	9.6
Alliant Energy Corp.	1.80	43.87	4.3	5.8	5.9	6.0	6.2	6.0	10.3
Atmos Energy Corp.	1.38	32.25	4.5	6.0	5.4	4.0	4.8	5.0	9.5
Consolidated Edison	2.42	59.15	4.2	3.4	3.4	4.0	3.6	3.6	7.8
Integrys Energy Group Inc.	2.72	53.62	5.4	4.3	7.2	7.0	4.5	5.8	11.1
Northwest Natural Gas	1.78	45.63	4.1	3.4	4.2	4.0	4.3	4.0	8.0
Piedmont Natural Gas	1.20	30.37	4.1	4.0	5.2	2.5	4.8	4.1	8.2
Southern Company	1.96	45.53	4.5	5.7	5.6	5.0	5.0	5.3	9.9
Vectren Corp.	1.40	29.01	5.1	5.6	5.5	6.5	4.3	5.5	10.6
WGL Holdings Inc.	1.60	39.52	4.2	5.5	4.6	3.0	4.9	4.5	8.7
Wisconsin Energy Corp.	1.20	36.40	3.5	4.5	6.2	6.5	5.3	5.6	9.1
Xcel Energy Inc.	1.04	27.12	4.0	4.6	5.1	5.0	4.9	4.9	8.9
Mean	**1.70**	**40.06**	**4.4**	**4.7**	**5.2**	**4.9**	**4.7**	**4.9**	**9.3**
Median	**1.69**	**38.88**	**4.3**	**4.5**	**5.3**	**5.0**	**4.8**	**5.0**	**9.3**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))
[2/] Expected Dividend Yield (Col (3)) + Average of All EPS Estimates (Col (8))

Source: Bloomberg, www.reuters.com, Value Line (May and June 2012), www.yahoo.com, and www.zacks.com.

DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(SUSTAINABLE GROWTH)

Company	Annualized Last Paid Dividend	Average Daily Close Prices 3/16-6/15/2012	Expected Dividend Yield 1/	Forecast Return on Common Equity	Forecast Earnings Retention Rate	BR Growth 2/ (2nd Qtr.2012)	SV Growth 3/ (2nd Qtr.2012)	Sustainable Growth 4/ (2nd Qtr.2012)	DCF Cost of Equity 5/
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
AGL Resources Inc.	1.84	38.25	5.1	11.6	51.2	5.9	0.28	6.2	11.3
Alliant Energy Corp.	1.80	43.87	4.3	11.0	37.1	4.1	0.25	4.3	8.6
Atmos Energy Corp.	1.38	32.25	4.4	7.9	45.2	3.6	0.03	3.6	8.0
Consolidated Edison	2.42	59.15	4.2	9.2	41.2	3.8	0.00	3.8	8.0
Integrys Energy Group Inc.	2.72	53.62	5.2	9.9	34.1	3.4	0.00	3.4	8.6
Northwest Natural Gas	1.78	45.63	4.2	12.0	42.9	5.1	1.47	6.6	10.8
Piedmont Natural Gas	1.20	30.37	4.1	12.8	27.0	3.5	-0.71	2.8	6.8
Southern Company	1.96	45.53	4.5	12.6	30.8	3.9	0.70	4.6	9.1
Vectren Corp.	1.40	29.01	5.1	12.2	36.0	4.4	0.64	5.0	10.1
WGL Holdings Inc.	1.60	39.52	4.2	10.0	37.5	3.7	0.10	3.8	8.0
Wisconsin Energy Corp.	1.20	36.40	3.4	13.9	34.5	4.8	-0.33	4.5	7.9
Xcel Energy Inc.	1.04	27.12	4.0	10.6	40.0	4.2	0.32	4.5	8.5
Mean	**1.70**	**40.06**	**4.4**	**11.14**	**38.14**	**4.20**	**0.23**	**4.4**	**8.8**
Median	**1.69**	**38.88**	**4.3**	**11.33**	**37.32**	**3.99**	**0.17**	**4.4**	**8.6**

1/ Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))
2/ BR Growth = Col (4) * (Col (5) / 100)
3/ SV Growth = Percent expected growth in number of shares of stock * Percent of funds from new equity financing that accrues to existing shareholders [1- B/M].
4/ Col (6) + Col (7)
5/ Expected Dividend Yield Col (3) + Sustainable Growth Col (8)

Source: *Value Line* (May and June 2012) and www.yahoo.com.

DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(THREE-STAGE MODEL)

Company	Annualized Last Paid Dividend	Average Daily Close Prices 3/16-6/15/2012	Growth Rates: Stage 1: Average of All EPS Forecasts	Growth Rates: Stage 2: Average of Stage 1 & 3	Growth Rates: Stage 3: GDP Growth [1/]	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)	(6)
AGL Resources Inc.	1.84	38.25	4.6	4.7	4.9	9.8
Alliant Energy Corp.	1.80	43.87	6.0	5.4	4.9	9.4
Atmos Energy Corp.	1.38	32.25	5.0	5.0	4.9	9.4
Consolidated Edison	2.42	59.15	3.6	4.2	4.9	8.7
Integrys Energy Group Inc.	2.72	53.62	5.8	5.3	4.9	10.5
Northwest Natural Gas	1.78	45.63	4.0	4.4	4.9	8.6
Piedmont Natural Gas	1.20	30.37	4.1	4.5	4.9	8.7
Southern Company	1.96	45.53	5.3	5.1	4.9	9.5
Vectren Corp.	1.40	29.01	5.5	5.2	4.9	10.1
WGL Holdings Inc.	1.60	39.52	4.5	4.7	4.9	8.9
Wisconsin Energy Corp.	1.20	36.40	5.6	5.3	4.9	8.4
Xcel Energy Inc.	1.04	27.12	4.9	4.9	4.9	8.8
Mean	**1.70**	**40.06**	**4.9**	**4.9**	**4.9**	**9.2**
Median	**1.69**	**38.88**	**5.0**	**4.9**	**4.9**	**9.2**

[1/] Forecast nominal rate of GDP growth, 2013-23

[2/] Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Bloomberg, Blue Chip *Economic Indicators* (March 2012), www.reuters.com, *Value Line* (May and June 2012), www.yahoo.com, and www.zacks.com.

DCF COST OF EQUITY FOR SAMPLE OF CANADIAN UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend (1)	Average Daily Close Prices 3/16-6/15/2012 (2)	Expected Dividend Yield [1/] (3)	Reuters Long-Term EPS Forecasts (4)	DCF Cost of Equity [2/] (5)
Canadian Utilities Limited	1.77	67.48	2.8	6.2	8.9
Emera Inc.	1.35	33.82	4.3	6.5	10.7
Enbridge Inc.	1.13	39.53	3.2	10.4	13.6
Fortis Inc.	1.20	33.07	3.9	6.9	10.8
TransCanada Corp.	1.76	42.85	4.4	7.8	12.2
Mean	**1.44**	**43.35**	**3.7**	**7.5**	**11.2**
Median	**1.35**	**39.53**	**3.9**	**6.9**	**10.8**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + EPS Estimate (Col (4))

Source: www.reuters.com and www.yahoo.com.

DCF COSTS OF EQUITY FOR SAMPLE OF CANADIAN UTILITIES
(THREE-STAGE MODEL)

Company	Annualized Last Paid Dividend	Average Daily Close Prices 3/16-6/15/2012	Growth Rates: Stage 1: Reuters Long-Term EPS Forecasts	Growth Rates: Stage 2: Average of Stage 1 & 3	Growth Rates: Stage 3: GDP Growth [1/]	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)	(6)
Canadian Utilities Limited	1.77	67.48	6.2	5.2	4.3	7.2
Emera Inc.	1.35	33.82	6.5	5.4	4.3	9.0
Enbridge Inc.	1.13	39.53	10.4	7.4	4.3	8.6
Fortis Inc.	1.20	33.07	6.9	5.6	4.3	8.7
TransCanada Corp.	1.76	42.85	7.8	6.0	4.3	9.5
Mean	**1.44**	**43.35**	**7.5**	**5.9**	**4.3**	**8.6**
Median	**1.35**	**39.53**	**6.9**	**5.6**	**4.3**	**8.7**

[1/] Forecast nominal rate of GDP growth, 2013-22
[2/] Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Consensus Economics, *Consensus Forecasts* (April 2012), www.reuters.com, and www.yahoo.com.

RISK MEASURES FOR 21 CANADIAN LOW RISK UNREGULATED COMPANIES

Company Name	Debt Ratings S&P	Debt Ratings DBRS	Average of Five Year Betas Ending: 2010-2011	Average of Five Year Betas Ending: 2004-2011	2010 Common Stock Equity (Total Capital)	Average Market to Book Ratio 1995-2011	Average Market to Book Ratio 2004-2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
ALGOMA CENTRAL CORP			0.92	0.73	79.3%	1.01	1.03
ASTRAL MEDIA INC			0.68	0.74	69.5%	1.75	1.78
CANADA BREAD CO LTD			0.64	0.63	98.5%	1.98	2.18
CANADIAN NATIONAL RAILWAY CO	A-	A(low)	0.64	0.73	65.0%	2.22	2.71
CANADIAN PACIFIC RAILWAY LTD	BBB-	BBB(low)	0.88	0.76	52.8%	1.66	1.81
CANADIAN TIRE CORP	BBB+	BBB(high)	0.71	0.72	76.9%	1.68	1.72
EMPIRE CO LTD			0.45	0.56	73.9%	1.40	1.31
LEON'S FURNITURE LTD			0.80	0.69	100.0%	2.45	2.52
LOBLAW COMPANIES LTD	BBB	BBB	0.58	0.54	58.7%	3.07	2.16
MAPLE LEAF FOODS INC			0.46	0.50	59.1%	2.09	1.60
METRO INC	BBB	BBB	0.45	0.57	70.7%	2.43	2.17
REITMANS (CANADA)			0.77	0.74	97.9%	1.82	2.62
RITCHIE BROS AUCTIONEERS INC			0.65	0.47	80.8%	4.84	4.84
SAPUTO INC			0.51	0.55	79.5%	3.65	3.26
SHOPPERS DRUG MART CORP	BBB+	A(low)	0.62	0.65	77.1%	3.32	3.28
THOMSON-REUTERS CORP	A-	A(low)	0.56	0.61	71.9%	2.36	1.84
TOROMONT INDUSTRIES LTD		BBB(high)	0.84	0.76	74.2%	2.79	2.67
TORSTAR CORP		BBB	0.91	0.67	63.7%	1.99	1.46
TRANSCONTINENTAL INC	BBB	BBB(high)	0.96	0.82	58.2%	1.52	1.37
UNI-SELECT INC			0.64	0.58	68.9%	2.07	1.86
WESTON (GEORGE) LTD	BBB	BBB	0.28	0.36	52.2%	2.69	2.17
Mean	**BBB+/BBB**	**BBB(high)**	**0.66**	**0.63**	**72.8%**	**2.32**	**2.21**
Median	**BBB**	**BBB(high)/BBB**	**0.65**	**0.64**	**71.9%**	**2.09**	**2.16**

Source: Standard and Poor's Research Insight and DBRS

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR 21 CANADIAN LOW RISK UNREGULATED COMPANIES

Company Name	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Average 1995-2011	Average 2004-2011
ALGOMA CENTRAL CORP	13.3	12.3	52.7	8.5	3.8	1.1	14.8	9.3	4.7	9.2	11.2	13.4	15.1	10.3	8.8	7.3	14.9	**12.4**	**11.3**
ASTRAL MEDIA INC	1.3	-9.5	7.1	7.8	6.4	4.4	8.2	10.0	10.0	10.9	12.1	13.1	13.0	14.7	-12.6	14.8	13.4	**7.4**	**9.9**
CANADA BREAD CO LTD	12.6	12.8	14.2	1.3	2.7	7.4	8.6	13.9	9.6	14.3	14.5	9.5	13.7	9.7	10.6	8.0	7.2	**10.0**	**10.9**
CANADIAN NATIONAL RAILWAY CO	-43.7	6.1	13.9	2.8	12.6	14.4	12.5	8.9	11.2	18.8	18.8	21.9	21.6	18.3	17.0	18.7	22.4	**11.5**	**19.7**
CANADIAN PACIFIC RAILWAY LTD	-13.0	13.5	18.0	10.3	7.3	20.2	6.6	15.2	11.3	10.8	13.0	17.2	18.3	10.8	9.6	11.3	12.0	**11.3**	**12.9**
CANADIAN TIRE CORP	10.2	10.4	11.4	13.0	11.2	10.6	11.5	11.9	12.8	13.6	13.9	13.4	14.2	11.2	9.2	11.7	11.0	**11.8**	**12.3**
EMPIRE CO LTD	3.9	11.9	17.9	21.7	13.3	69.1	16.4	11.4	11.6	11.4	16.2	10.3	14.0	10.5	10.7	11.9	9.2	**16.0**	**11.8**
LEON'S FURNITURE LTD	14.0	13.4	15.1	16.7	21.1	19.3	17.3	17.1	16.5	18.9	19.2	19.6	19.2	18.8	15.6	16.1	13.6	**17.1**	**17.6**
LOBLAW COMPANIES LTD	13.3	14.2	15.3	12.8	13.7	15.7	16.8	18.9	19.1	19.1	13.2	-3.9	6.0	9.6	10.8	10.4	11.9	**12.8**	**9.6**
MAPLE LEAF FOODS INC	-6.7	14.8	14.7	-6.3	17.9	8.0	10.3	12.2	4.8	13.0	9.9	0.5	19.2	-3.2	4.5	2.1	7.9	**7.3**	**6.7**
METRO INC	22.6	22.8	24.7	20.5	20.8	22.8	24.1	23.9	23.8	21.0	16.1	15.6	15.1	14.7	16.4	16.6	15.4	**19.8**	**16.4**
REITMANS (CANADA)	6.2	0.8	8.9	9.4	30.1	10.2	12.6	10.5	15.4	22.0	23.5	20.0	24.7	16.9	13.0	16.8	9.4	**14.7**	**18.3**
RITCHIE BROS AUCTIONEERS INC	nc	35.6	19.9	38.8	18.2	12.4	13.1	15.5	14.7	12.4	17.2	16.5	17.5	24.8	17.2	11.5	12.9	**18.6**	**16.3**
SAPUTO INC	nc	37.3	18.9	19.3	18.6	16.0	19.4	18.1	19.5	18.8	14.1	16.2	18.3	15.5	19.1	21.7	21.5	**19.5**	**18.2**
SHOPPERS DRUG MART CORP	na	na	na	na	nc	2.5	2.0	13.8	15.0	15.8	16.0	16.5	17.0	17.2	16.1	14.7	14.5	**13.4**	**16.0**
THOMSON-REUTERS CORP	22.4	14.2	12.9	34.7	8.0	17.9	10.2	7.3	8.8	10.3	9.3	11.0	31.1	9.1	4.0	4.6	-7.9	**12.2**	**8.9**
TOROMONT INDUSTRIES LTD	27.1	24.3	47.5	22.5	16.6	15.4	16.4	12.7	16.9	17.8	17.6	19.0	20.0	19.6	14.8	9.6	30.5	**20.5**	**18.6**
TORSTAR CORP	6.7	11.3	38.4	-0.7	12.8	5.4	-14.6	21.3	17.8	14.6	14.5	9.2	11.3	-22.7	5.3	8.7	30.6	**10.0**	**8.9**
TRANSCONTINENTAL INC	9.3	0.8	10.6	11.2	11.4	13.7	4.0	18.9	17.5	13.9	13.3	12.2	10.3	0.7	-7.7	15.4	6.5	**9.5**	**8.1**
UNI-SELECT INC	21.4	19.9	20.7	20.6	18.7	15.2	16.1	16.7	19.2	15.5	16.3	15.4	13.7	13.6	10.3	12.0	13.0	**16.4**	**13.7**
WESTON (GEORGE) LTD	12.9	15.1	14.5	37.3	14.0	17.4	18.5	18.3	19.4	10.2	16.2	1.6	12.7	17.5	17.6	7.1	11.9	**15.4**	**11.9**
Average	**7.4**	**14.1**	**19.9**	**15.1**	**14.0**	**15.2**	**11.7**	**14.6**	**14.3**	**14.9**	**15.1**	**12.8**	**16.5**	**11.3**	**10.0**	**12.0**	**13.4**	**13.7**	**13.2**
Median	**11.4**	**13.5**	**15.2**	**12.9**	**13.5**	**14.4**	**12.6**	**13.9**	**15.0**	**14.3**	**14.5**	**13.4**	**15.1**	**13.6**	**10.7**	**11.7**	**12.9**	**12.8**	**12.3**
Average of Annual Medians																		**13.4**	**13.5**

Source: Standard and Poor's Research Insight.

MARKET VALUE CAPITAL STRUCTURES FOR SAMPLE OF CANADIAN UTILITIES

	Debt and Preferred Shares at Par (Millions $, March 2012)	Common Share Price Average Daily Close 3/16-6/15/2012	Common Shares Outstanding (Millions, March 2012)	Total Market Capitalization (Millions $)	Market Value Common Equity Ratio
	(1)	(2)	(3)	(4)	(5)
Canadian Utilities Limited	5,395	67.48	128	8,613	61.5%
Emera Inc.	3,700	33.82	123	4,176	53.0%
Enbridge Inc.	22,107	39.53	785	31,031	58.4%
Fortis Inc.	6,889	33.07	189	6,261	47.6%
TransCanada Corp.	22,406	42.85	704	30,165	57.4%
Mean				**$16,049**	**55.6%**
Median				**$8,613**	**57.4%**

MARKET VALUE CAPITAL STRUCTURES FOR SAMPLE OF U.S. UTILITIES

	Debt and Preferred Shares at Par (Millions $, March 2012)	Common Share Price Average Daily Close 3/16-6/15/2012	Common Shares Outstanding (Millions, March 2012)	Total Market Capitalization (Millions $)	Market Value Common Equity Ratio
	(1)	(2)	(3)	(4)	(5)
AGL Resources Inc.	4,288	38.25	117	4,463	51.0%
Alliant Energy Corp.	2,992	43.87	111	4,857	61.9%
Atmos Energy Corp.	2,380	32.25	90	2,904	55.0%
Consolidated Edison	11,071	59.15	293	17,326	61.0%
Integrys Energy Group Inc.	2,479	53.62	78	4,178	62.8%
Northwest Natural Gas	755	45.63	27	1,222	61.8%
Piedmont Natural Gas	1,133	30.37	72	2,191	65.9%
Southern Company	22,668	45.53	868	39,521	63.6%
Vectren Corp.	1,796	29.01	82	2,376	57.0%
WGL Holdings Inc.	771	39.52	52	2,035	72.5%
Wisconsin Energy Corp.	5,224	36.40	231	8,390	61.6%
Xcel Energy Inc.	10,247	27.12	487	13,218	56.3%
Mean				**$8,557**	**60.9%**
Median				**$4,321**	**61.7%**

Source: Reports to Shareholders, www.yahoo.com

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES:

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

APPROACH 1:
The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity increases as leverage (debt ratio)

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Where LL = less levered (lower debt ratio)
ML = more levered (higher debt ratio)

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for A rated utility
	=	5.35%
Equity Cost	=	9.60%
Tax Rate	=	26.25%
CEQ Ratio	Step (1)	57.0%
Debt Ratio	Step (1)	43.0%
CEQ Ratio	Step (2)	40.0%
Debt Ratio	Step (2)	60.0%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sa (common equity ratio of 57.0%)

$WACC_{AT}$ = (5.35%)(1-.263)(43.0%) + (9.60%)(57.0%)
= 7.17%

2. Estimate Cost of Equity for sample at 40.0% common equity ratio $WACC_{AT}$ unchanged at 7.17%

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
7.17% = (5.35%)(1-.263)(60.0%) + (X)(40.0%)
Cost of Equity at 40.0% Equity Ratio = 12.00%

3. Difference between Equity Return at 57.0% and 40.0% common equity ratios:

12.00% - 9.60% = 2.40% (240 basis points)

APPROACH 2:

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for A rated utility
	=	5.35%
Equity Cost	=	9.60%
Tax Rate	=	26.3%
CEQ Ratio	Step (1)	57.0%
Debt Ratio	Step (1)	43.0%
CEQ Ratio	Step (2)	40.0%
Debt Ratio	Step (2)	60.0%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 57.0%)

   $WACC_{AT}$ = (5.35%)(1-.263)(43.0%) + (9.60%)(57.0%)
   = 7.17%

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 40.0%)

   $WACC_{AT(ML)} = WACC_{AT(LL)}$ x (1-t x Debt $Ratio_{ML}$)/(1-t x Debt $Ratio_{LL}$)

   $$WACC_{AT(ML)} = 7.17\% \times \frac{(1-.263 \times 60.0\%)}{(1-.263 \times 43.0\%)}$$

   $WACC_{AT(ML)}$ = 6.81%

3. Estimate Cost of Equity at new $WACC_{AT}$ for more levered firm:

   $WACC_{AT(ML)}$ = (Debt Cost)(1-tax rate)(Debt $Ratio_{ML}$) + (Equity Cost)(Equity $Ratio_{ML}$)
   6.81% = (5.35%)(1-.263)(60.0%) + (X)(40.0%)
   Cost of Equity at 40.0% Equity Ratio = 11.10%

4. Difference between Equity Return at 57.0% and 40.0% common equity ratios:

   11.10% - 9.60% = 1.50% (150 basis points)

Attachment 36.1

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
9/30/2009	3.31	3.84
10/1/2009	3.25	3.81
10/2/2009	3.26	3.82
10/5/2009	3.24	3.8
10/6/2009	3.29	3.84
10/7/2009	3.28	3.84
10/8/2009	3.35	3.89
10/9/2009	3.51	3.96
10/13/2009	3.49	3.94
10/14/2009	3.52	3.98
10/15/2009	3.55	4
10/16/2009	3.48	3.95
10/19/2009	3.5	3.97
10/20/2009	3.42	3.93
10/21/2009	3.44	3.94
10/22/2009	3.46	3.94
10/23/2009	3.5	3.98
10/26/2009	3.54	4.02
10/27/2009	3.48	3.98
10/28/2009	3.45	3.96
10/29/2009	3.5	3.98
10/30/2009	3.42	3.92
11/2/2009	3.44	3.94
11/3/2009	3.43	3.94
11/4/2009	3.48	3.99
11/5/2009	3.53	4.03
11/6/2009	3.52	4.03
11/9/2009	3.5	4.02
11/10/2009	3.5	4.02
11/12/2009	3.51	4.03
11/13/2009	3.47	3.99
11/16/2009	3.39	3.93
11/17/2009	3.37	3.91
11/18/2009	3.41	3.95
11/19/2009	3.38	3.92
11/20/2009	3.38	3.93
11/23/2009	3.37	3.93
11/24/2009	3.28	3.85
11/25/2009	3.25	3.85
11/26/2009	3.2	3.82
11/27/2009	3.22	3.84
11/30/2009	3.22	3.84
12/1/2009	3.25	3.87
12/2/2009	3.25	3.88
12/3/2009	3.23	3.87
12/4/2009	3.32	3.91
12/7/2009	3.28	3.9
12/8/2009	3.29	3.93

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
12/9/2009	3.32	3.96
12/10/2009	3.35	3.99
12/11/2009	3.38	3.99
12/14/2009	3.4	4.01
12/15/2009	3.4	4
12/16/2009	3.4	3.99
12/17/2009	3.37	3.97
12/18/2009	3.41	4.01
12/21/2009	3.51	4.08
12/22/2009	3.59	4.12
12/23/2009	3.57	4.07
12/24/2009	3.6	4.08
12/29/2009	3.61	4.09
12/30/2009	3.6	4.07
12/31/2009	3.61	4.08
1/4/2010	3.6	4.1
1/5/2010	3.56	4.08
1/6/2010	3.62	4.14
1/7/2010	3.63	4.15
1/8/2010	3.59	4.11
1/11/2010	3.61	4.14
1/12/2010	3.55	4.09
1/13/2010	3.61	4.14
1/14/2010	3.55	4.09
1/15/2010	3.49	4.05
1/18/2010	3.47	4.04
1/19/2010	3.48	4.04
1/20/2010	3.42	4.01
1/21/2010	3.39	4
1/22/2010	3.37	3.99
1/25/2010	3.38	4
1/26/2010	3.36	3.97
1/27/2010	3.35	3.96
1/28/2010	3.33	3.93
1/29/2010	3.34	3.94
2/1/2010	3.38	3.98
2/2/2010	3.37	3.99
2/3/2010	3.42	4.04
2/4/2010	3.36	3.99
2/5/2010	3.36	4
2/8/2010	3.35	3.99
2/9/2010	3.38	4.01
2/10/2010	3.43	4.04
2/11/2010	3.47	4.06
2/12/2010	3.46	4.06
2/16/2010	3.44	4.06
2/17/2010	3.47	4.08
2/18/2010	3.49	4.08

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
2/19/2010	3.5	4.07
2/22/2010	3.5	4.09
2/23/2010	3.43	4.03
2/24/2010	3.45	4.05
2/25/2010	3.4	4.02
2/26/2010	3.39	4.02
3/1/2010	3.4	4.02
3/2/2010	3.39	4
3/3/2010	3.42	4.01
3/4/2010	3.42	4.01
3/5/2010	3.47	4.06
3/8/2010	3.51	4.1
3/9/2010	3.51	4.11
3/10/2010	3.53	4.12
3/11/2010	3.5	4.08
3/12/2010	3.53	4.09
3/15/2010	3.49	4.06
3/16/2010	3.44	4.02
3/17/2010	3.47	4.04
3/18/2010	3.45	4.02
3/19/2010	3.49	4.05
3/22/2010	3.45	4.03
3/23/2010	3.47	4.03
3/24/2010	3.54	4.09
3/25/2010	3.54	4.08
3/26/2010	3.55	4.08
3/29/2010	3.57	4.1
3/30/2010	3.58	4.1
3/31/2010	3.56	4.07
4/1/2010	3.55	4.05
4/5/2010	3.66	4.12
4/6/2010	3.68	4.11
4/7/2010	3.62	4.07
4/8/2010	3.67	4.1
4/9/2010	3.65	4.06
4/12/2010	3.66	4.06
4/13/2010	3.68	4.08
4/14/2010	3.71	4.11
4/15/2010	3.72	4.1
4/16/2010	3.68	4.08
4/19/2010	3.65	4.06
4/20/2010	3.7	4.07
4/21/2010	3.72	4.06
4/22/2010	3.72	4.09
4/23/2010	3.69	4.07
4/26/2010	3.68	4.06
4/27/2010	3.6	4.01
4/28/2010	3.66	4.04

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
4/29/2010	3.72	4.05
4/30/2010	3.65	4.01
5/3/2010	3.64	4
5/4/2010	3.55	3.95
5/5/2010	3.54	3.93
5/6/2010	3.47	3.87
5/7/2010	3.5	3.88
5/10/2010	3.58	3.93
5/11/2010	3.58	3.93
5/12/2010	3.59	3.94
5/13/2010	3.51	3.87
5/14/2010	3.43	3.82
5/17/2010	3.5	3.88
5/18/2010	3.4	3.82
5/19/2010	3.4	3.81
5/20/2010	3.32	3.75
5/21/2010	3.36	3.77
5/25/2010	3.26	3.7
5/26/2010	3.25	3.68
5/27/2010	3.37	3.75
5/28/2010	3.3	3.71
5/31/2010	3.36	3.73
6/1/2010	3.29	3.71
6/2/2010	3.38	3.77
6/3/2010	3.39	3.78
6/4/2010	3.28	3.71
6/7/2010	3.3	3.71
6/8/2010	3.32	3.73
6/9/2010	3.35	3.76
6/10/2010	3.43	3.83
6/11/2010	3.41	3.81
6/14/2010	3.44	3.84
6/15/2010	3.42	3.83
6/16/2010	3.36	3.78
6/17/2010	3.31	3.75
6/18/2010	3.32	3.76
6/21/2010	3.32	3.76
6/22/2010	3.25	3.71
6/23/2010	3.23	3.69
6/24/2010	3.23	3.7
6/25/2010	3.19	3.68
6/28/2010	3.16	3.68
6/29/2010	3.09	3.65
6/30/2010	3.08	3.65
7/2/2010	3.1	3.65
7/5/2010	3.07	3.63
7/6/2010	3.07	3.64
7/7/2010	3.16	3.69

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
7/8/2010	3.19	3.72
7/9/2010	3.23	3.75
7/12/2010	3.21	3.75
7/13/2010	3.27	3.78
7/14/2010	3.26	3.78
7/15/2010	3.23	3.77
7/16/2010	3.16	3.72
7/19/2010	3.16	3.74
7/20/2010	3.2	3.76
7/21/2010	3.15	3.73
7/22/2010	3.21	3.77
7/23/2010	3.23	3.78
7/26/2010	3.23	3.77
7/27/2010	3.26	3.8
7/28/2010	3.22	3.77
7/29/2010	3.17	3.75
7/30/2010	3.11	3.69
8/3/2010	3.1	3.69
8/4/2010	3.17	3.72
8/5/2010	3.11	3.67
8/6/2010	3.07	3.65
8/9/2010	3.07	3.65
8/10/2010	3.03	3.63
8/11/2010	2.97	3.6
8/12/2010	3.01	3.63
8/13/2010	2.98	3.6
8/16/2010	2.93	3.55
8/17/2010	2.96	3.57
8/18/2010	2.94	3.55
8/19/2010	2.92	3.52
8/20/2010	2.92	3.53
8/23/2010	2.88	3.53
8/24/2010	2.82	3.5
8/25/2010	2.83	3.47
8/26/2010	2.8	3.43
8/27/2010	2.87	3.49
8/30/2010	2.78	3.43
8/31/2010	2.78	3.44
9/1/2010	2.85	3.5
9/2/2010	2.87	3.52
9/3/2010	2.95	3.57
9/7/2010	2.81	3.47
9/8/2010	2.92	3.53
9/9/2010	2.97	3.56
9/10/2010	2.97	3.55
9/13/2010	2.95	3.54
9/14/2010	2.94	3.52
9/15/2010	2.96	3.54

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
9/16/2010	2.97	3.55
9/17/2010	2.93	3.5
9/20/2010	2.94	3.5
9/21/2010	2.89	3.48
9/22/2010	2.87	3.43
9/23/2010	2.83	3.41
9/24/2010	2.86	3.42
9/27/2010	2.8	3.38
9/28/2010	2.74	3.33
9/29/2010	2.74	3.33
9/30/2010	2.75	3.35
10/1/2010	2.79	3.39
10/4/2010	2.75	3.37
10/5/2010	2.77	3.39
10/6/2010	2.74	3.38
10/7/2010	2.75	3.42
10/8/2010	2.68	3.4
10/12/2010	2.72	3.43
10/13/2010	2.73	3.44
10/14/2010	2.76	3.45
10/15/2010	2.79	3.49
10/18/2010	2.76	3.48
10/19/2010	2.71	3.45
10/20/2010	2.75	3.46
10/21/2010	2.76	3.44
10/22/2010	2.74	3.44
10/25/2010	2.74	3.43
10/26/2010	2.82	3.46
10/27/2010	2.89	3.5
10/28/2010	2.87	3.48
10/29/2010	2.8	3.44
11/1/2010	2.83	3.47
11/2/2010	2.88	3.48
11/3/2010	2.87	3.49
11/4/2010	2.81	3.47
11/5/2010	2.85	3.49
11/8/2010	2.89	3.5
11/9/2010	2.97	3.57
11/10/2010	2.98	3.59
11/12/2010	3.02	3.63
11/15/2010	3.14	3.71
11/16/2010	3.07	3.68
11/17/2010	3.1	3.67
11/18/2010	3.12	3.66
11/19/2010	3.14	3.62
11/22/2010	3.08	3.58
11/23/2010	3.11	3.6
11/24/2010	3.19	3.65

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
11/25/2010	3.16	3.63
11/26/2010	3.11	3.57
11/29/2010	3.08	3.52
11/30/2010	3.07	3.48
12/1/2010	3.17	3.58
12/2/2010	3.2	3.6
12/3/2010	3.19	3.64
12/6/2010	3.12	3.6
12/7/2010	3.23	3.68
12/8/2010	3.25	3.68
12/9/2010	3.25	3.69
12/10/2010	3.31	3.71
12/13/2010	3.24	3.66
12/14/2010	3.34	3.75
12/15/2010	3.3	3.74
12/16/2010	3.26	3.68
12/17/2010	3.18	3.6
12/20/2010	3.17	3.58
12/21/2010	3.14	3.55
12/22/2010	3.17	3.56
12/23/2010	3.18	3.56
12/24/2010	3.17	3.56
12/29/2010	3.16	3.54
12/30/2010	3.16	3.55
12/31/2010	3.11	3.52
1/4/2011	3.17	3.57
1/5/2011	3.27	3.66
1/6/2011	3.22	3.64
1/7/2011	3.18	3.61
1/10/2011	3.17	3.6
1/11/2011	3.22	3.64
1/12/2011	3.26	3.68
1/13/2011	3.25	3.67
1/14/2011	3.27	3.69
1/17/2011	3.25	3.68
1/18/2011	3.27	3.71
1/19/2011	3.23	3.69
1/20/2011	3.3	3.74
1/21/2011	3.32	3.74
1/24/2011	3.31	3.75
1/25/2011	3.27	3.72
1/26/2011	3.31	3.75
1/27/2011	3.28	3.72
1/28/2011	3.24	3.71
1/31/2011	3.27	3.73
2/1/2011	3.34	3.77
2/2/2011	3.38	3.79
2/3/2011	3.42	3.8

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
2/4/2011	3.46	3.82
2/7/2011	3.43	3.8
2/8/2011	3.49	3.85
2/9/2011	3.45	3.81
2/10/2011	3.47	3.83
2/11/2011	3.47	3.83
2/14/2011	3.49	3.84
2/15/2011	3.48	3.84
2/16/2011	3.5	3.85
2/17/2011	3.49	3.85
2/18/2011	3.47	3.85
2/22/2011	3.36	3.79
2/23/2011	3.32	3.75
2/24/2011	3.32	3.72
2/25/2011	3.29	3.7
2/28/2011	3.3	3.7
3/1/2011	3.29	3.7
3/2/2011	3.33	3.74
3/3/2011	3.39	3.8
3/4/2011	3.33	3.77
3/7/2011	3.35	3.8
3/8/2011	3.4	3.84
3/9/2011	3.34	3.79
3/10/2011	3.27	3.74
3/11/2011	3.27	3.75
3/14/2011	3.22	3.73
3/15/2011	3.2	3.72
3/16/2011	3.13	3.68
3/17/2011	3.19	3.72
3/18/2011	3.17	3.71
3/21/2011	3.21	3.73
3/22/2011	3.18	3.7
3/23/2011	3.21	3.7
3/24/2011	3.22	3.7
3/25/2011	3.23	3.7
3/28/2011	3.26	3.7
3/29/2011	3.3	3.74
3/30/2011	3.29	3.72
3/31/2011	3.35	3.75
4/1/2011	3.37	3.77
4/4/2011	3.35	3.76
4/5/2011	3.38	3.77
4/6/2011	3.41	3.82
4/7/2011	3.43	3.84
4/8/2011	3.44	3.85
4/11/2011	3.48	3.87
4/12/2011	3.42	3.82
4/13/2011	3.37	3.79

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
4/14/2011	3.36	3.77
4/15/2011	3.3	3.72
4/18/2011	3.23	3.68
4/19/2011	3.27	3.71
4/20/2011	3.33	3.76
4/21/2011	3.29	3.74
4/25/2011	3.24	3.71
4/26/2011	3.19	3.68
4/27/2011	3.27	3.74
4/28/2011	3.23	3.7
4/29/2011	3.2	3.69
5/2/2011	3.2	3.69
5/3/2011	3.16	3.64
5/4/2011	3.11	3.6
5/5/2011	3.09	3.57
5/6/2011	3.2	3.58
5/9/2011	3.18	3.58
5/10/2011	3.26	3.64
5/11/2011	3.22	3.62
5/12/2011	3.23	3.62
5/13/2011	3.2	3.59
5/16/2011	3.18	3.58
5/17/2011	3.16	3.56
5/18/2011	3.22	3.61
5/19/2011	3.21	3.59
5/20/2011	3.15	3.56
5/24/2011	3.11	3.52
5/25/2011	3.08	3.5
5/26/2011	3.04	3.48
5/27/2011	3.06	3.5
5/30/2011	3.06	3.49
5/31/2011	3.07	3.49
6/1/2011	2.99	3.45
6/2/2011	3.02	3.5
6/3/2011	2.99	3.47
6/6/2011	3	3.49
6/7/2011	3.03	3.52
6/8/2011	3.01	3.49
6/9/2011	3.04	3.52
6/10/2011	3.01	3.48
6/13/2011	3	3.46
6/14/2011	3.07	3.5
6/15/2011	2.95	3.42
6/16/2011	2.92	3.39
6/17/2011	2.94	3.39
6/20/2011	2.97	3.42
6/21/2011	2.98	3.42
6/22/2011	2.97	3.42

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
6/23/2011	2.9	3.37
6/24/2011	2.86	3.36
6/27/2011	2.9	3.42
6/28/2011	2.98	3.47
6/29/2011	3.09	3.53
6/30/2011	3.11	3.55
7/4/2011	3.08	3.53
7/5/2011	3.07	3.52
7/6/2011	3.05	3.5
7/7/2011	3.06	3.49
7/8/2011	2.96	3.41
7/11/2011	2.9	3.36
7/12/2011	2.9	3.36
7/13/2011	2.93	3.38
7/14/2011	2.95	3.4
7/15/2011	2.87	3.35
7/18/2011	2.87	3.36
7/19/2011	2.89	3.34
7/20/2011	2.94	3.39
7/21/2011	3	3.43
7/22/2011	2.93	3.39
7/25/2011	2.93	3.4
7/26/2011	2.89	3.37
7/27/2011	2.88	3.35
7/28/2011	2.88	3.34
7/29/2011	2.79	3.29
8/2/2011	2.63	3.16
8/3/2011	2.66	3.19
8/4/2011	2.5	3.09
8/5/2011	2.64	3.22
8/8/2011	2.47	3.11
8/9/2011	2.45	3.07
8/10/2011	2.32	2.99
8/11/2011	2.46	3.07
8/12/2011	2.46	3.09
8/15/2011	2.5	3.13
8/16/2011	2.46	3.11
8/17/2011	2.39	3.05
8/18/2011	2.3	2.96
8/19/2011	2.3	2.96
8/22/2011	2.3	2.95
8/23/2011	2.38	3.01
8/24/2011	2.46	3.08
8/25/2011	2.4	3.04
8/26/2011	2.39	3.01
8/29/2011	2.46	3.06
8/30/2011	2.4	3.02
8/31/2011	2.49	3.1

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
9/1/2011	2.39	3.03
9/2/2011	2.3	2.96
9/6/2011	2.24	2.91
9/7/2011	2.27	2.95
9/8/2011	2.21	2.89
9/9/2011	2.11	2.81
9/12/2011	2.14	2.81
9/13/2011	2.19	2.83
9/14/2011	2.2	2.85
9/15/2011	2.29	2.91
9/16/2011	2.29	2.92
9/19/2011	2.18	2.87
9/20/2011	2.2	2.86
9/21/2011	2.12	2.76
9/22/2011	2.02	2.68
9/23/2011	2.07	2.7
9/26/2011	2.15	2.77
9/27/2011	2.2	2.82
9/28/2011	2.19	2.83
9/29/2011	2.22	2.84
9/30/2011	2.15	2.77
10/3/2011	2.06	2.69
10/4/2011	2.1	2.71
10/5/2011	2.14	2.73
10/6/2011	2.22	2.8
10/7/2011	2.24	2.82
10/11/2011	2.3	2.87
10/12/2011	2.35	2.95
10/13/2011	2.29	2.89
10/14/2011	2.4	2.97
10/17/2011	2.29	2.88
10/18/2011	2.31	2.91
10/19/2011	2.34	2.94
10/20/2011	2.31	2.93
10/21/2011	2.36	2.98
10/24/2011	2.36	2.99
10/25/2011	2.26	2.92
10/26/2011	2.38	3.02
10/27/2011	2.49	3.13
10/28/2011	2.43	3.06
10/31/2011	2.29	2.92
11/1/2011	2.15	2.79
11/2/2011	2.17	2.81
11/3/2011	2.21	2.86
11/4/2011	2.16	2.83
11/7/2011	2.15	2.81
11/8/2011	2.18	2.81
11/9/2011	2.09	2.73

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
11/10/2011	2.14	2.76
11/14/2011	2.11	2.74
11/15/2011	2.11	2.74
11/16/2011	2.09	2.72
11/17/2011	2.1	2.71
11/18/2011	2.13	2.74
11/21/2011	2.1	2.72
11/22/2011	2.08	2.68
11/23/2011	2.04	2.63
11/24/2011	2.05	2.63
11/25/2011	2.11	2.66
11/28/2011	2.12	2.67
11/29/2011	2.13	2.67
11/30/2011	2.15	2.69
12/1/2011	2.13	2.69
12/2/2011	2.12	2.68
12/5/2011	2.09	2.66
12/6/2011	2.13	2.68
12/7/2011	2.06	2.63
12/8/2011	1.99	2.58
12/9/2011	2.06	2.65
12/12/2011	2.01	2.62
12/13/2011	1.98	2.57
12/14/2011	1.95	2.54
12/15/2011	1.93	2.52
12/16/2011	1.87	2.46
12/19/2011	1.84	2.42
12/20/2011	1.93	2.46
12/21/2011	1.95	2.49
12/22/2011	1.95	2.5
12/23/2011	2.01	2.55
12/28/2011	1.96	2.5
12/29/2011	1.94	2.5
12/30/2011	1.94	2.49
1/3/2012	1.99	2.55
1/4/2012	1.99	2.57
1/5/2012	1.97	2.55
1/6/2012	1.94	2.52
1/9/2012	1.95	2.52
1/10/2012	1.98	2.54
1/11/2012	1.93	2.51
1/12/2012	1.98	2.54
1/13/2012	1.93	2.51
1/16/2012	1.94	2.51
1/17/2012	1.92	2.5
1/18/2012	1.96	2.53
1/19/2012	2	2.57
1/20/2012	2.06	2.63

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
1/23/2012	2.08	2.66
1/24/2012	2.08	2.67
1/25/2012	2.04	2.64
1/26/2012	2.02	2.62
1/27/2012	1.99	2.6
1/30/2012	1.94	2.55
1/31/2012	1.89	2.5
2/1/2012	1.9	2.52
2/2/2012	1.94	2.55
2/3/2012	2.01	2.61
2/6/2012	1.98	2.57
2/7/2012	2.04	2.62
2/8/2012	2.06	2.64
2/9/2012	2.09	2.64
2/10/2012	2.05	2.62
2/13/2012	2.07	2.64
2/14/2012	2.02	2.6
2/15/2012	2.01	2.59
2/16/2012	2.03	2.61
2/17/2012	2.05	2.64
2/21/2012	2.09	2.66
2/22/2012	2.05	2.64
2/23/2012	2.05	2.64
2/24/2012	2.02	2.64
2/27/2012	2	2.62
2/28/2012	1.98	2.6
2/29/2012	1.98	2.6
3/1/2012	2	2.61
3/2/2012	1.96	2.58
3/5/2012	1.98	2.58
3/6/2012	1.94	2.55
3/7/2012	1.97	2.57
3/8/2012	2.01	2.59
3/9/2012	2.01	2.59
3/12/2012	1.99	2.58
3/13/2012	2.06	2.63
3/14/2012	2.17	2.7
3/15/2012	2.21	2.74
3/16/2012	2.24	2.77
3/19/2012	2.29	2.81
3/20/2012	2.28	2.81
3/21/2012	2.24	2.77
3/22/2012	2.2	2.73
3/23/2012	2.18	2.72
3/26/2012	2.19	2.72
3/27/2012	2.12	2.67
3/28/2012	2.12	2.67
3/29/2012	2.08	2.64

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
3/30/2012	2.11	2.66
4/2/2012	2.13	2.66
4/3/2012	2.19	2.73
4/4/2012	2.13	2.68
4/5/2012	2.13	2.68
4/9/2012	2.07	2.63
4/10/2012	1.98	2.55
4/11/2012	2.01	2.58
4/12/2012	2.05	2.6
4/13/2012	1.99	2.55
4/16/2012	2.01	2.57
4/17/2012	2.07	2.61
4/18/2012	2.04	2.59
4/19/2012	2.04	2.58
4/20/2012	2.06	2.61
4/23/2012	2.04	2.59
4/24/2012	2.07	2.62
4/25/2012	2.1	2.65
4/26/2012	2.05	2.61
4/27/2012	2.09	2.63
4/30/2012	2.04	2.61
5/1/2012	2.05	2.61
5/2/2012	2.02	2.59
5/3/2012	2	2.59
5/4/2012	2.02	2.54
5/7/2012	2.02	2.54
5/8/2012	1.97	2.5
5/9/2012	1.99	2.51
5/10/2012	1.99	2.5
5/11/2012	1.97	2.47
5/14/2012	1.94	2.44
5/15/2012	1.93	2.45
5/16/2012	1.93	2.45
5/17/2012	1.88	2.42
5/18/2012	1.89	2.43
5/22/2012	1.91	2.44
5/23/2012	1.88	2.4
5/24/2012	1.86	2.4
5/25/2012	1.8	2.35
5/28/2012	1.84	2.37
5/29/2012	1.87	2.39
5/30/2012	1.79	2.33
5/31/2012	1.74	2.29
6/1/2012	1.62	2.21
6/4/2012	1.68	2.23
6/5/2012	1.74	2.28
6/6/2012	1.8	2.35
6/7/2012	1.8	2.36

'V39055=Government of Canada benchmark bond yields - 10 year
'V39056=Government of Canada benchmark bond yields - long-term

	V39055	V39056
Date	10 Year Canada	30 Year Canada
6/8/2012	1.81	2.36
6/11/2012	1.76	2.33
6/12/2012	1.8	2.37
6/13/2012	1.77	2.35
6/14/2012	1.79	2.37
6/15/2012	1.72	2.33
6/18/2012	1.71	2.34
6/19/2012	1.76	2.36
6/20/2012	1.77	2.36
6/21/2012	1.75	2.32
6/22/2012	1.8	2.36
6/25/2012	1.73	2.3
6/26/2012	1.75	2.32
6/27/2012	1.72	2.32
6/28/2012	1.68	2.29
6/29/2012	1.74	2.33

Attachment 36.2

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Attachment 44.1

Coastal Region (LM)

YE Accounts by rate class

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate 1	534,987	538,473	541,959	545,472	549,001	552,082	555,041	557,952	560,779	563,553	566,249
Rate 2	54,558	55,021	55,484	55,954	56,430	56,829	57,207	57,574	57,929	58,277	58,608
Rate 3	4,242	4,305	4,376	4,447	4,518	4,582	4,641	4,699	4,756	4,813	4,867
Rate 4	33	33	33	33	33	33	33	33	33	33	33
Rate 5	221	221	221	221	221	221	221	221	221	221	221
Rate 6	26	26	26	26	26	26	26	26	26	26	26
Rate 7	1	1	1	1	1	1	1	1	1	1	1
Rate 22	22	22	22	22	22	22	22	22	22	22	22
Rate 23	1,126	1,131	1,136	1,141	1,146	1,148	1,149	1,150	1,151	1,152	1,153
Rate 25	488	488	488	488	488	488	488	488	488	488	488
Rate 27	81	81	81	81	81	81	81	81	81	81	81
Total Coastal Region	595,785	599,802	603,827	607,886	611,967	615,513	618,910	622,247	625,487	628,667	631,749

Annual Demand by Rate Class(TJ)

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate 1	50,929	50,560	50,280	50,093	49,999	49,960	50,006	50,045	50,074	50,096	50,109
Rate 2	18,222	18,322	18,421	18,577	18,678	18,754	18,878	18,942	19,001	19,115	19,165
Rate 3	13,757	13,961	14,191	14,422	14,652	14,859	15,051	15,239	15,424	15,609	15,784
Rate 4	76	76	76	76	76	76	76	76	76	76	76
Rate 5	2,300	2,276	2,252	2,230	2,209	2,188	2,168	2,147	2,127	2,107	2,087
Rate 6	68	68	68	68	68	68	68	68	68	68	68
Rate 7	3	3	3	3	3	3	3	3	3	3	3
Rate 22	13,412	13,210	13,009	12,933	12,858	12,783	12,710	12,637	12,564	12,493	12,422
Rate 23	5,478	5,502	5,527	5,551	5,575	5,585	5,590	5,595	5,600	5,604	5,609
Rate 25	8,511	8,399	8,287	8,231	8,175	8,120	8,066	8,012	7,958	7,906	7,853
Rate 27	4,708	4,659	4,611	4,589	4,567	4,546	4,525	4,504	4,483	4,463	4,442
Total Coastal Region	**117,464**	**117,036**	**116,724**	**116,772**	**116,861**	**116,942**	**117,139**	**117,266**	**117,378**	**117,539**	**117,619**

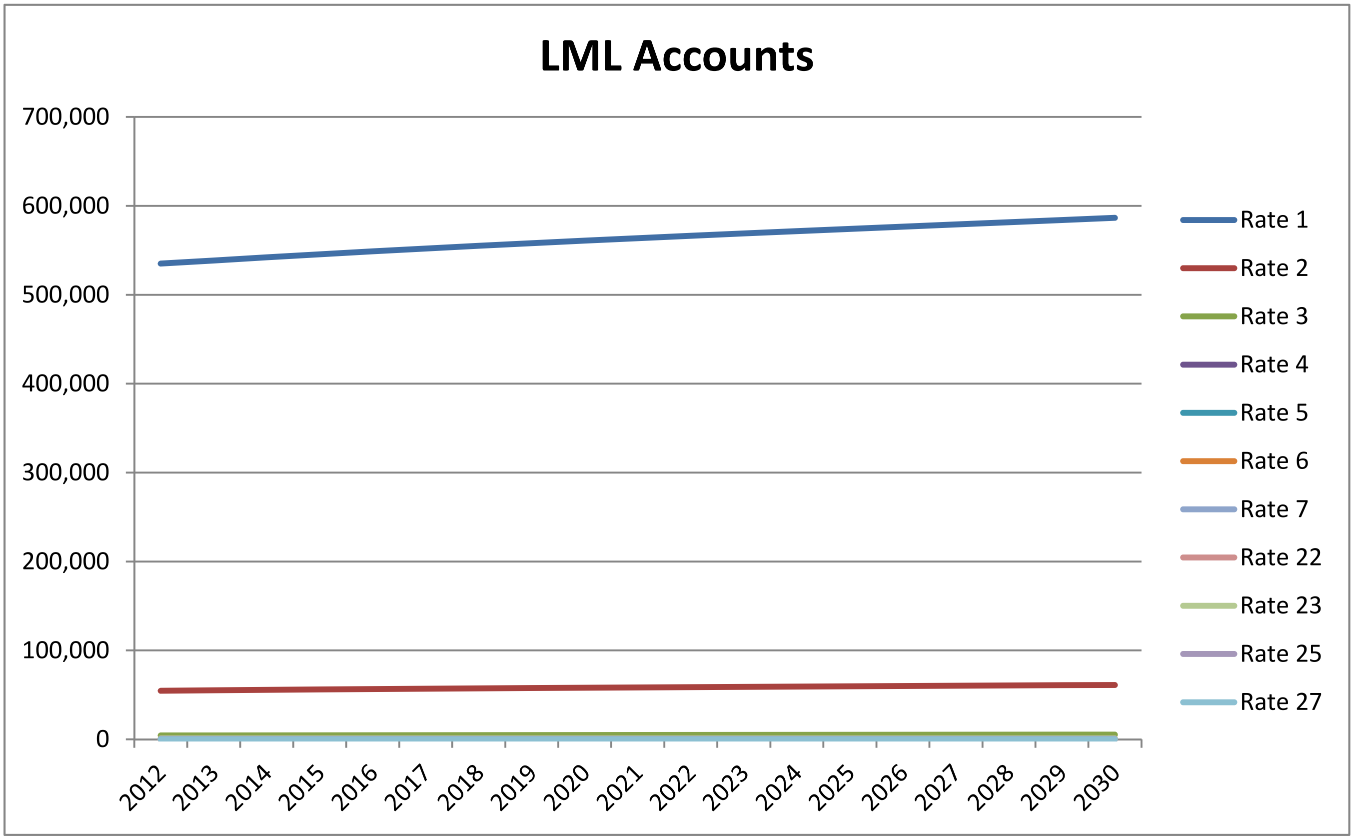
Coastal Region (LM)

YE Accounts by rate class

Core	2023	2024	2025	2026	2027	2028	2029	2030
Rate 1	568,930	571,518	574,086	576,607	579,101	581,568	584,022	586,447
Rate 2	58,939	59,251	59,563	59,871	60,175	60,476	60,774	61,070
Rate 3	4,921	4,975	5,029	5,082	5,134	5,188	5,243	5,296
Rate 4	33	33	33	33	33	33	33	33
Rate 5	221	221	221	221	221	221	221	221
Rate 6	26	26	26	26	26	26	26	26
Rate 7	1	1	1	1	1	1	1	1
Rate 22	22	22	22	22	22	22	22	22
Rate 23	1,154	1,155	1,156	1,157	1,158	1,159	1,160	1,161
Rate 25	488	488	488	488	488	488	488	488
Rate 27	81	81	81	81	81	81	81	81
Total Coastal Region	634,816	637,771	640,706	643,589	646,440	649,263	652,071	654,846

Annual Demand by Rate Class(TJ)

Core	2023	2024	2025	2026	2027	2028	2029	2030
Rate 1	50,119	50,118	50,114	50,103	50,088	50,069	50,047	50,020
Rate 2	19,214	19,316	19,358	19,398	19,497	19,534	19,630	19,665
Rate 3	15,959	16,134	16,309	16,481	16,650	16,825	17,003	17,175
Rate 4	76	76	76	76	76	76	76	76
Rate 5	2,068	2,048	2,029	2,010	1,991	1,973	1,954	1,936
Rate 6	68	68	68	68	68	68	68	68
Rate 7	3	2	2	2	2	2	2	2
Rate 22	12,352	12,282	12,214	12,146	12,078	12,012	11,946	11,880
Rate 23	5,614	5,619	5,624	5,629	5,634	5,639	5,643	5,648
Rate 25	7,802	7,750	7,700	7,649	7,600	7,550	7,502	7,453
Rate 27	4,422	4,402	4,383	4,363	4,344	4,325	4,306	4,287
Total Coastal Region	**117,696**	**117,817**	**117,876**	**117,926**	**118,028**	**118,072**	**118,177**	**118,211**


LML Accounts
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600,000
500,000
400,000
300,000
200,000
100,000
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
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2022
2023
2024
2025
2026
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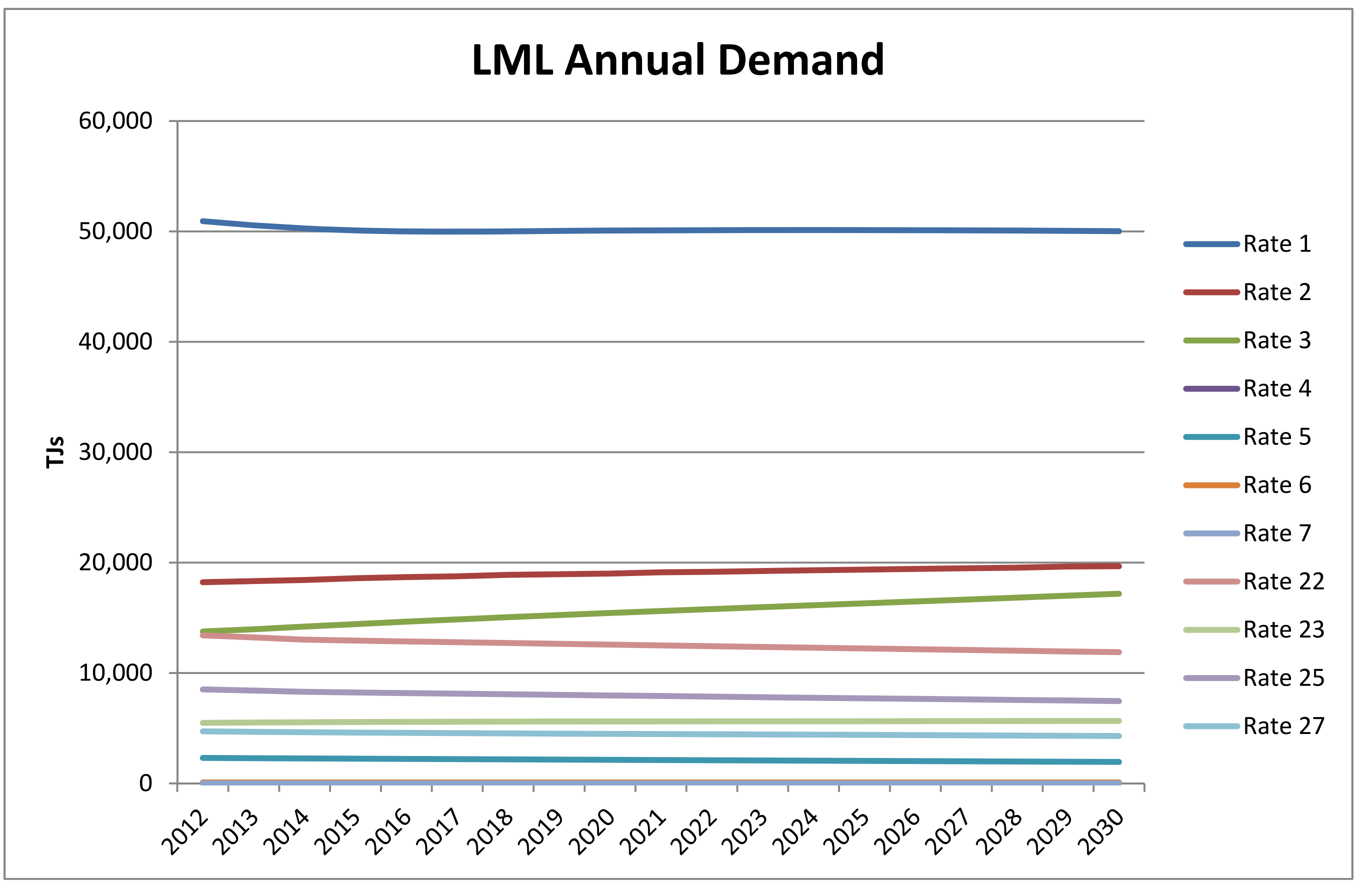
2030
Rate 1
Rate 2
Rate 3
Rate 4
Rate 5
Rate 6
Rate 7
Rate 22
Rate 23
Rate 25
Rate 27


LML Annual Demand
TJs
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40,000
30,000
20,000
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2012
2013
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2016
2017
2018
2019
2020
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2022
2023
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2025
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2028
2029
2030
Rate 1
Rate 2
Rate 3
Rate 4
Rate 5
Rate 6
Rate 7
Rate 22
Rate 23
Rate 25
Rate 27

FEVI

Year end accounts by Rate Class

Rate Class	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
RGS	96,379	99,199	102,086	105,095	108,187	110,640	112,820	114,956	117,025	118,942	120,876
SCS1	5384	5496	5611	5731	5855	5950	6032	6112	6187	6255	6324
SCS2	1430	1435	1440	1446	1452	1455	1458	1461	1463	1464	1465
LCS1	1375	1380	1385	1390	1396	1399	1402	1405	1407	1408	1409
LCS2	541	546	551	557	563	567	570	573	575	577	579
AGS	891	896	901	906	911	915	918	921	923	925	927
LCS3	131	134	137	140	143	146	148	150	152	153	154
HLF	6	6	6	6	6	6	6	6	6	6	6
ILF	8	8	8	8	8	8	8	8	8	8	8
Total	**106,145**	**109,100**	**112,125**	**115,279**	**118,521**	**121,086**	**123,362**	**125,592**	**127,746**	**129,738**	**131,748**

Annual Demand by Rate Class(TJ)

Rate Class	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
RGS	4,639	4,636	4,648	4,680	4,731	4,772	4,821	4,866	4,907	4,940	4,972
SCS1	627	640	653	667	682	693	702	712	720	728	736
SCS2	465	466	468	470	472	473	474	475	475	476	476
LCS1	1,347	1,352	1,357	1,362	1,368	1,371	1,374	1,377	1,378	1,379	1,380
LCS2	1,342	1,355	1,367	1,382	1,397	1,407	1,414	1,422	1,427	1,432	1,437
AGS	1,122	1,128	1,134	1,141	1,147	1,152	1,156	1,160	1,162	1,165	1,167
LCS3	1,953	1,998	2,043	2,087	2,132	2,177	2,207	2,237	2,266	2,281	2,296
HLF	118	118	118	118	118	118	118	118	118	118	118
ILF	98	98	98	98	98	98	98	98	98	98	98

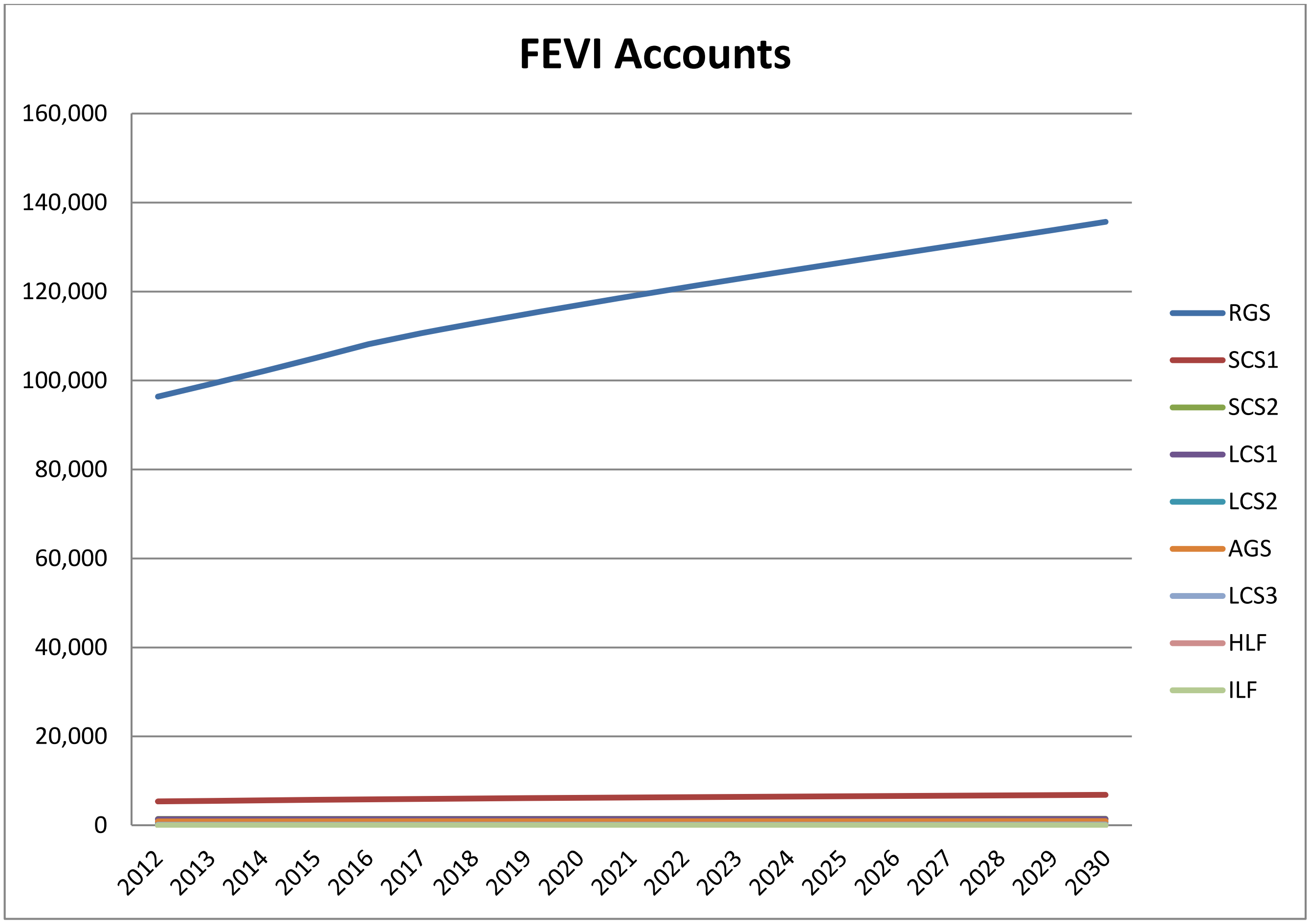
FEVI

Year end accounts by Rate Class

Rate Class	2023	2024	2025	2026	2027	2028	2029	2030
RGS	122,857	124,704	126,541	128,370	130,174	131,982	133,824	135,689
SCS1	6397	6461	6526	6591	6655	6719	6784	6849
SCS2	1467	1468	1469	1470	1471	1472	1473	1474
LCS1	1411	1412	1413	1414	1415	1416	1417	1418
LCS2	581	583	584	585	586	587	588	589
AGS	929	931	933	935	937	939	941	943
LCS3	156	157	158	159	160	161	162	163
HLF	6	6	6	6	6	6	6	6
ILF	8	8	8	8	8	8	8	8
Total	**133,812**	**135,730**	**137,638**	**139,538**	**141,412**	**143,290**	**145,203**	**147,139**

Annual Demand by Rate Class(TJ)

Rate Class	2023	2024	2025	2026	2027	2028	2029	2030
RGS	5,004	5,030	5,053	5,075	5,094	5,112	5,130	5,147
SCS1	745	752	760	767	775	782	790	797
SCS2	477	477	477	478	478	478	479	479
LCS1	1,382	1,383	1,384	1,385	1,386	1,387	1,388	1,389
LCS2	1,442	1,447	1,449	1,452	1,454	1,457	1,459	1,461
AGS	1,170	1,172	1,175	1,177	1,180	1,182	1,185	1,187
LCS3	2,326	2,341	2,356	2,371	2,386	2,401	2,416	2,430
HLF	118	118	118	118	118	118	118	118
ILF	98	98	98	98	98	98	98	98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RGS
SCS1
SCS2
LCS1
LCS2
AGS
LCS3
HLF
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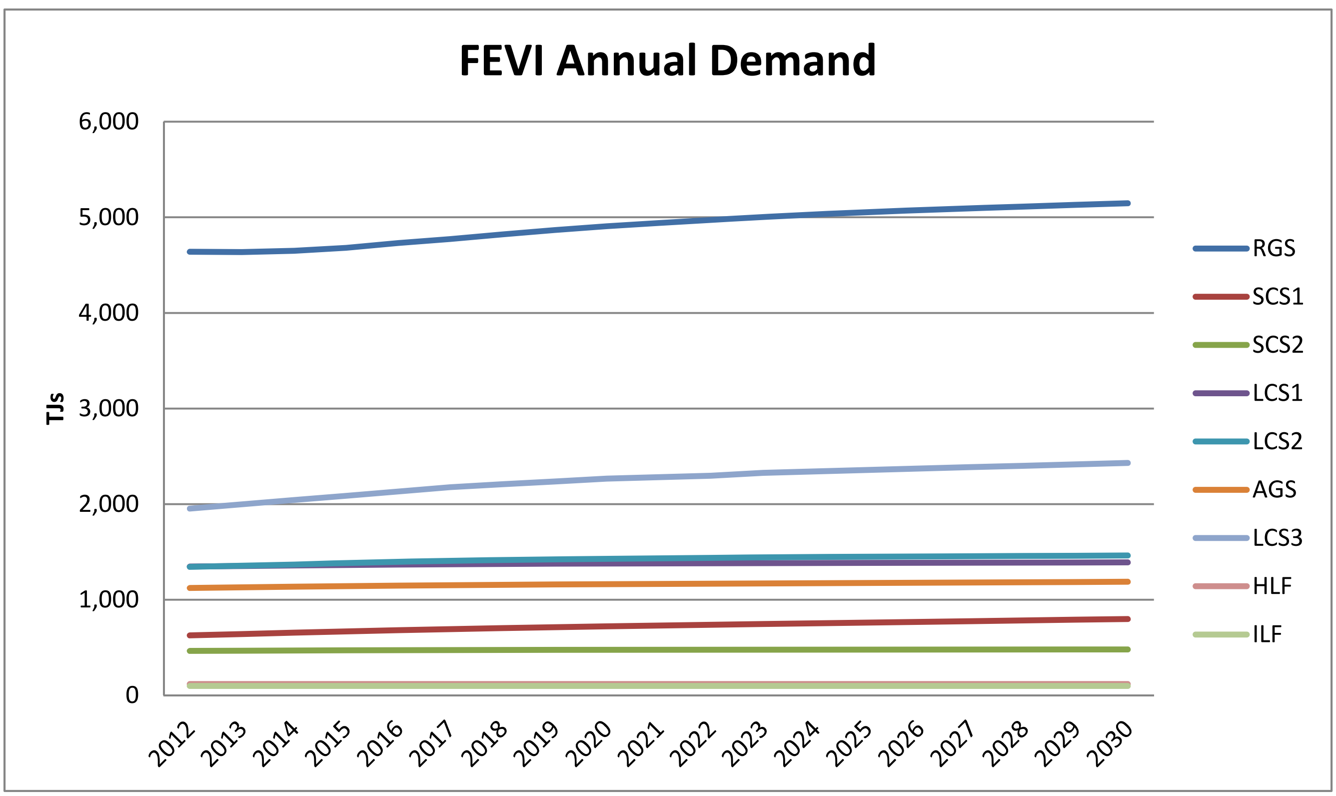
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3,000
2,000
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TJs
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2027
2028
2029
2030
RGS
SCS1
SCS2
LCS1
LCS2
AGS
LCS3
HLF
ILF

INL
YE Accounts by rate class

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate 1	213,808	215,967	218,126	220,359	222,628	224,367	225,945	227,474	228,916	230,319
Rate 2	21,059	21,287	21,515	21,750	21,986	22,170	22,339	22,500	22,654	22,800
Rate 3	793	824	855	887	921	949	976	1,003	1,028	1,053
Rate 4	12	12	12	12	12	12	12	12	12	12
Rate 5	28	28	28	28	28	28	28	28	28	28
Rate 6	2	2	2	2	2	2	2	2	2	2
Rate 7	2	2	2	2	2	2	2	2	2	2
Rate 22	17	17	17	17	17	17	17	17	17	17
Rate 23	232	236	240	244	248	251	254	257	260	263
Rate 25	86	86	86	86	86	86	86	86	86	86
Rate 27	14	14	14	14	14	14	14	14	14	14
Total	236,053	238,475	240,897	243,401	245,944	247,898	249,675	251,395	253,019	254,596

INL Annual Demand by Rate Class(TJ)

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate 1	15,290	15,142	15,032	14,965	14,941	14,923	14,938	14,948	14,951	14,951
Rate 2	5,897	5,939	6,003	6,047	6,112	6,141	6,188	6,210	6,230	6,270
Rate 3	2,626	2,728	2,831	2,937	3,049	3,142	3,232	3,321	3,404	3,486
Rate 4	115	115	115	115	115	115	115	115	115	115
Rate 5	375	372	368	364	361	358	354	351	348	345
Rate 6	7	7	7	7	7	7	7	7	7	7
Rate 7	4	4	4	4	4	4	4	3	3	3
Rate 22	10,235	9,534	8,833	8,830	8,827	8,825	8,822	8,819	8,816	8,814
Rate 23	1,259	1,280	1,302	1,324	1,345	1,362	1,378	1,394	1,411	1,427
Rate 25	3,066	3,048	3,029	3,018	3,006	2,995	2,984	2,973	2,962	2,952
Rate 27	637	627	616	613	610	608	605	602	600	597
INL total	**39,510**	**38,795**	**38,139**	**38,223**	**38,379**	**38,479**	**38,626**	**38,744**	**38,847**	**38,966**

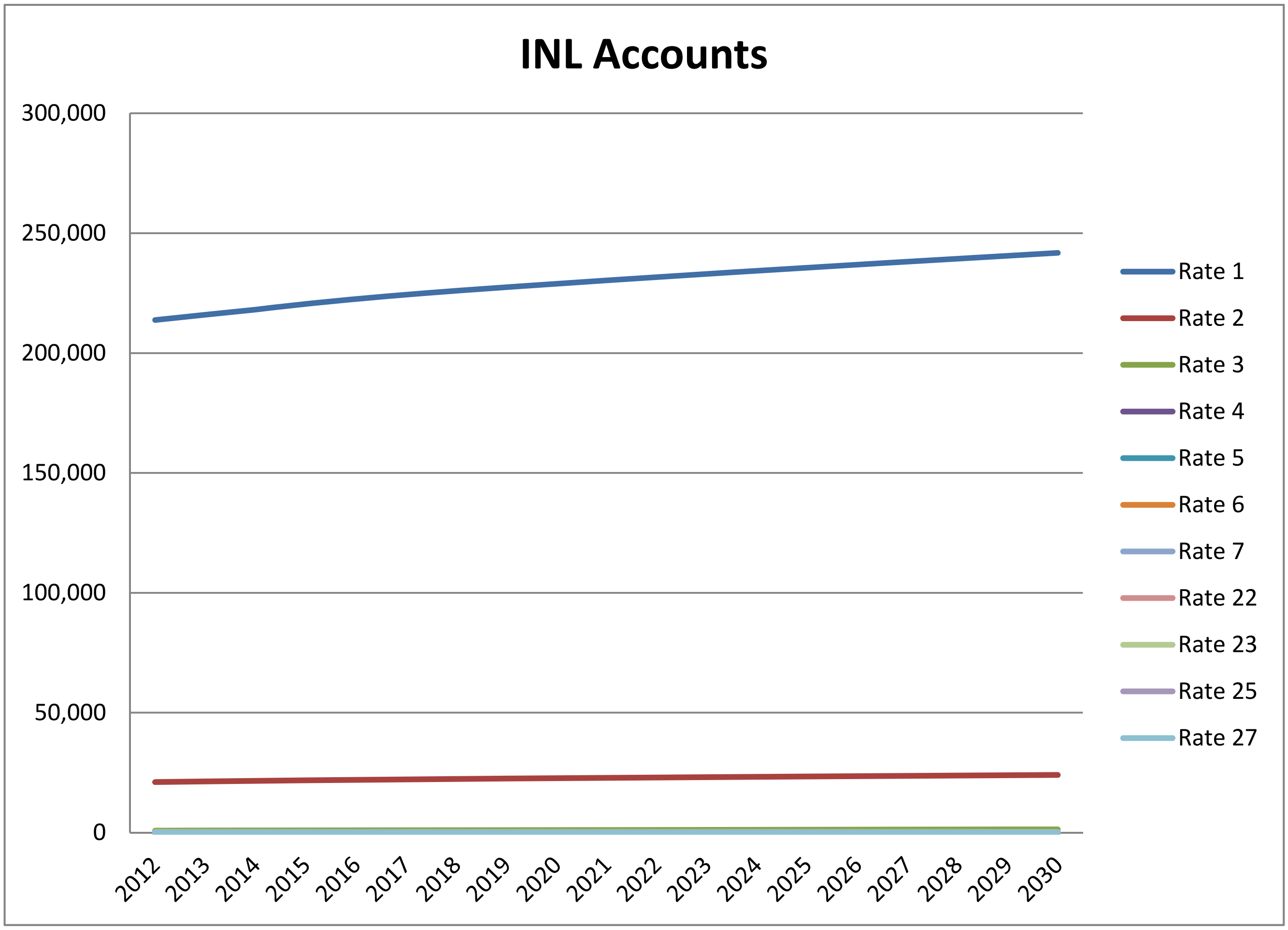
INL

YE Accounts by rate class

Core	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate 1	231,668	233,025	234,327	235,618	236,871	238,127	239,333	240,576	241,824
Rate 2	22,941	23,083	23,217	23,353	23,485	23,615	23,739	23,869	24,000
Rate 3	1,079	1,106	1,132	1,160	1,186	1,212	1,239	1,267	1,295
Rate 4	12	12	12	12	12	12	12	12	12
Rate 5	28	28	28	28	28	28	28	28	28
Rate 6	2	2	2	2	2	2	2	2	2
Rate 7	2	2	2	2	2	2	2	2	2
Rate 22	17	17	17	17	17	17	17	17	17
Rate 23	266	269	272	275	278	281	283	286	289
Rate 25	86	86	86	86	86	86	86	86	86
Rate 27	14	14	14	14	14	14	14	14	14
Total	256,115	257,644	259,109	260,567	261,981	263,396	264,755	266,159	267,569

INL Annual Demand by Rate Class(TJ)

Core	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate 1	14,945	14,940	14,930	14,918	14,902	14,886	14,866	14,847	14,827
Rate 2	6,286	6,325	6,338	6,375	6,388	6,423	6,433	6,468	6,480
Rate 3	3,573	3,662	3,748	3,841	3,927	4,013	4,102	4,195	4,288
Rate 4	115	115	115	115	115	115	115	115	115
Rate 5	341	338	335	332	329	326	323	320	317
Rate 6	7	7	7	7	7	7	7	7	7
Rate 7	3	3	3	3	3	3	3	3	3
Rate 22	8,811	8,808	8,806	8,803	8,801	8,798	8,796	8,793	8,791
Rate 23	1,443	1,459	1,476	1,492	1,508	1,524	1,535	1,552	1,568
Rate 25	2,941	2,931	2,920	2,910	2,900	2,890	2,880	2,870	2,860
Rate 27	594	592	589	587	584	582	579	577	575
INL total	**39,060**	**39,180**	**39,267**	**39,383**	**39,464**	**39,567**	**39,639**	**39,747**	**39,830**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Rate 1
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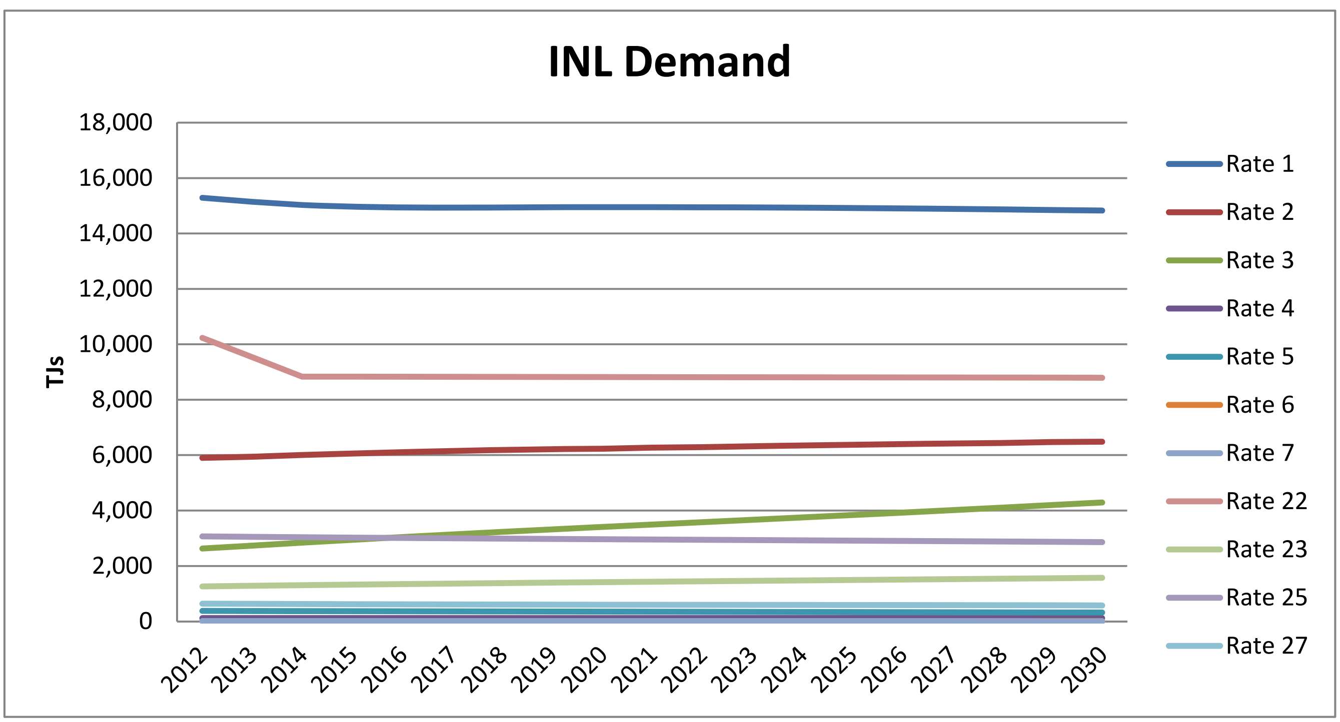
Rate 23
Rate 25
Rate 27


INL Demand
TJs
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Rate 1
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Rate 23
Rate 25
Rate 27

COL
YE Accounts by rate class

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate 1	20,771	20,949	21,127	21,312	21,499	21,671	21,874	22,029	22,182	22,294	22,400
Rate 2	2,153	2,182	2,211	2,243	2,274	2,305	2,340	2,370	2,398	2,420	2,440
Rate 3	89	92	95	99	102	105	109	111	113	115	117
Rate 4	0	0	0	0	0	0	0	0	0	0	0
Rate 5	4	4	4	4	4	4	4	4	4	4	4
Rate 6	0	0	0	0	0	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0	0	0	0	0	0
Rate 22	7	7	7	7	7	7	7	7	7	7	7
Rate 23	17	17	17	17	17	17	17	17	17	17	17
Rate 25	7	7	7	7	7	7	7	7	7	7	7
Rate 27	2	2	2	2	2	2	2	2	2	2	2
Total Region	23,050	23,260	23,470	23,691	23,912	24,118	24,360	24,547	24,730	24,866	24,994

COL Annual Demand by Rate Class(TJ)

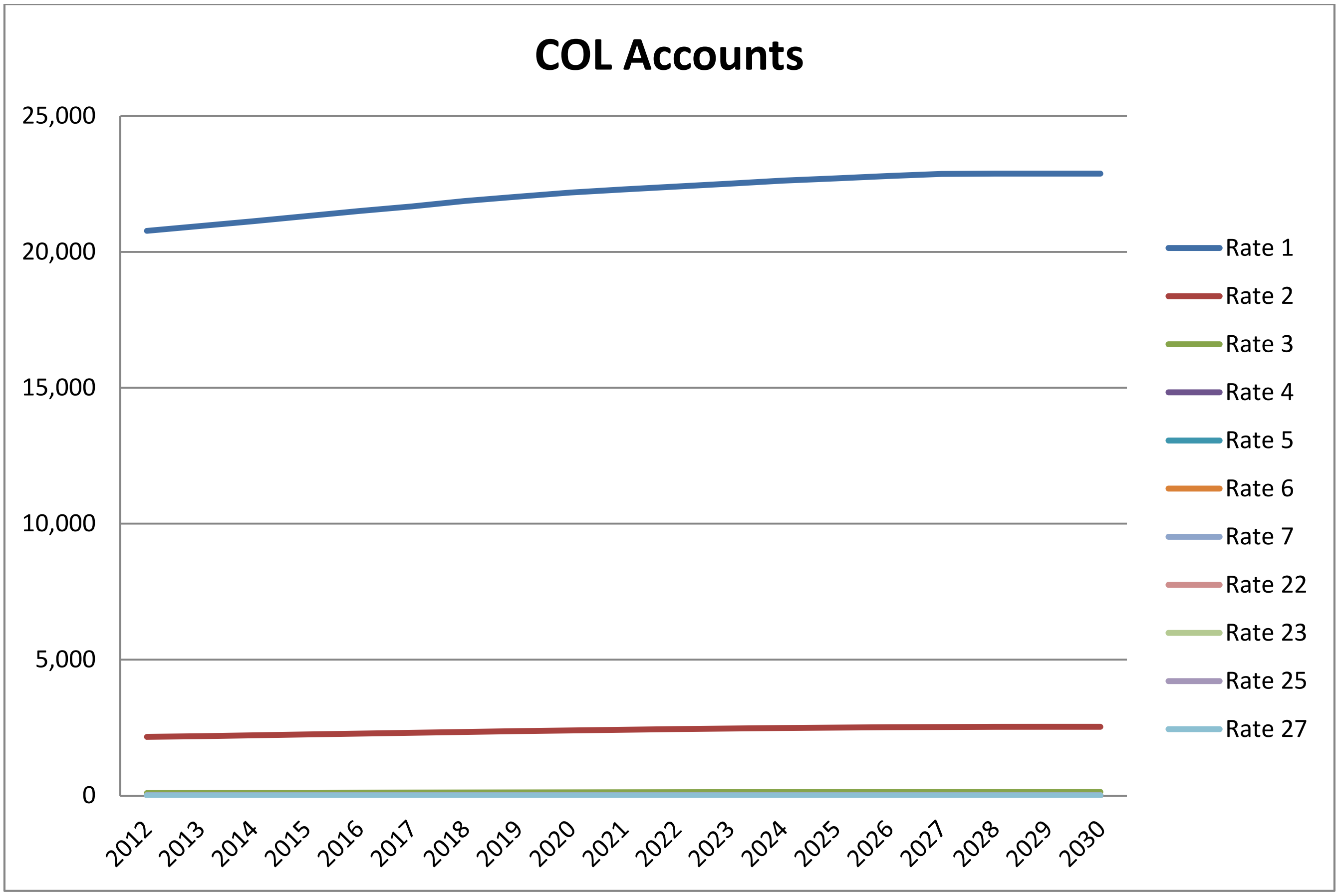
Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate 1	1,623	1,608	1,596	1,589	1,586	1,586	1,592	1,594	1,596	1,595	1,594
Rate 2	687	696	703	711	721	728	739	747	753	760	764
Rate 3	318	329	339	354	364	375	389	396	404	411	418
Rate 4											
Rate 5	37	37	36	36	36	35	35	35	34	34	34
Rate 6											
Rate 7	0	0	0	0	0	0	0	0	0	0	0
Rate 22	2,530	2,477	2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424
Rate 23	77	77	77	77	77	77	77	77	77	77	77
Rate 25	213	209	206	205	205	204	204	203	203	202	201
Rate 27	18	18	18	18	18	18	18	18	18	18	18
Total	**5,504**	**5,451**	**5,400**	**5,414**	**5,431**	**5,448**	**5,478**	**5,494**	**5,509**	**5,521**	**5,530**

COL
YE Accounts by rate class

Core	2023	2024	2025	2026	2027	2028	2029	2030
Rate 1	22,505	22,620	22,702	22,787	22,863	22,874	22,875	22,875
Rate 2	2,459	2,479	2,493	2,510	2,525	2,527	2,528	2,528
Rate 3	119	122	124	126	128	129	129	129
Rate 4	0	0	0	0	0	0	0	0
Rate 5	4	4	4	4	4	4	4	4
Rate 6	0	0	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0	0	0
Rate 22	7	7	7	7	7	7	7	7
Rate 23	17	17	17	17	17	17	17	17
Rate 25	7	7	7	7	7	7	7	7
Rate 27	2	2	2	2	2	2	2	2
Total Region	25,120	25,258	25,356	25,460	25,553	25,567	25,569	25,569

COL Annual Demand by Rate Class(TJ)

Core	2023	2024	2025	2026	2027	2028	2029	2030
Rate 1	1,593	1,592	1,588	1,585	1,581	1,573	1,564	1,555
Rate 2	767	773	775	781	783	781	781	779
Rate 3	425	436	443	450	457	461	461	461
Rate 4								
Rate 5	33	33	33	32	32	32	31	31
Rate 6								
Rate 7	0	0	0	0	0	0	0	0
Rate 22	2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424
Rate 23	77	77	77	77	77	77	77	77
Rate 25	201	200	200	199	199	198	198	197
Rate 27	18	18	18	18	18	18	18	18
Total	**5,538**	**5,554**	**5,558**	**5,567**	**5,571**	**5,564**	**5,554**	**5,542**


COL Accounts
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20,000
15,000
10,000
5,000
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2012
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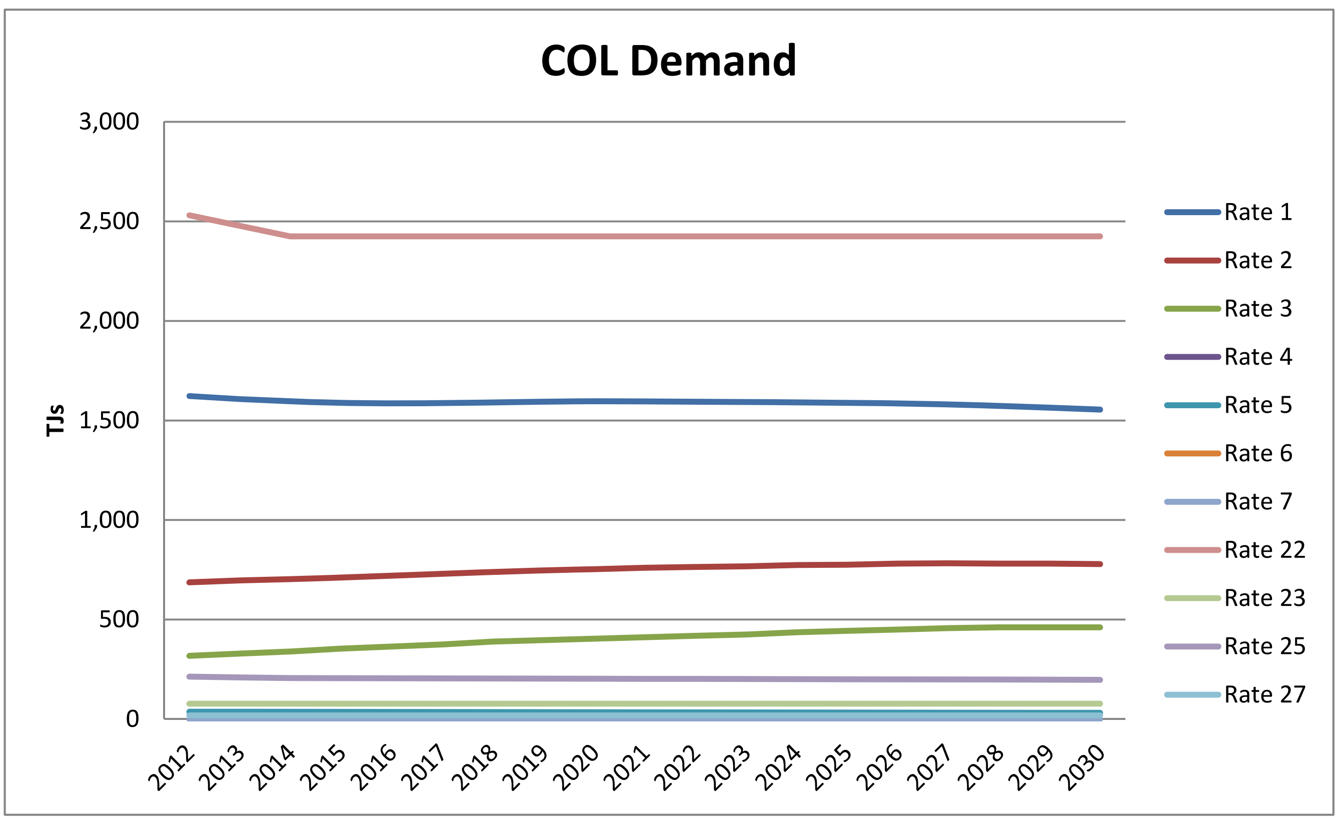
Rate 22
Rate 23
Rate 25
Rate 27


COL Demand
TJs
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2012
2013
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Rate 1
Rate 2
Rate 3
Rate 4
Rate 5
Rate 6
Rate 7
Rate 22
Rate 23
Rate 25
Rate 27

FEW

Year end accounts by Rate Class

Rate Class	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SGS-1/2 RES	2,341	2,366	2,396	2,426	2,455	2,478	2,498	2,520	2,538	2,555	2,572
SGS-1/2 COM	178	181	184	187	190	192	194	196	198	200	202
LGS-1 COM	85	85	86	86	87	87	88	88	89	89	90
LGS-2 COM	52	53	53	53	53	54	54	54	54	55	55
LGS-3 COM	24	24	24	24	24	24	24	24	24	24	24
NGV											

Annual Demand by Rate Class(TJ)

Rate Class	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SGS-1/2 RES	193	195	197	200	202	204	205	207	209	210	211
SGS-1/2 COM	45	45	46	47	48	48	49	49	50	50	51
LGS-1 COM	101	101	102	102	103	103	104	104	105	105	107
LGS-2 COM	127	130	130	130	130	132	132	132	132	135	135
LGS-3 COM	220	220	220	220	220	220	220	220	220	220	220
NGV	0	0	0	0	0	0	0	0	0	0	0

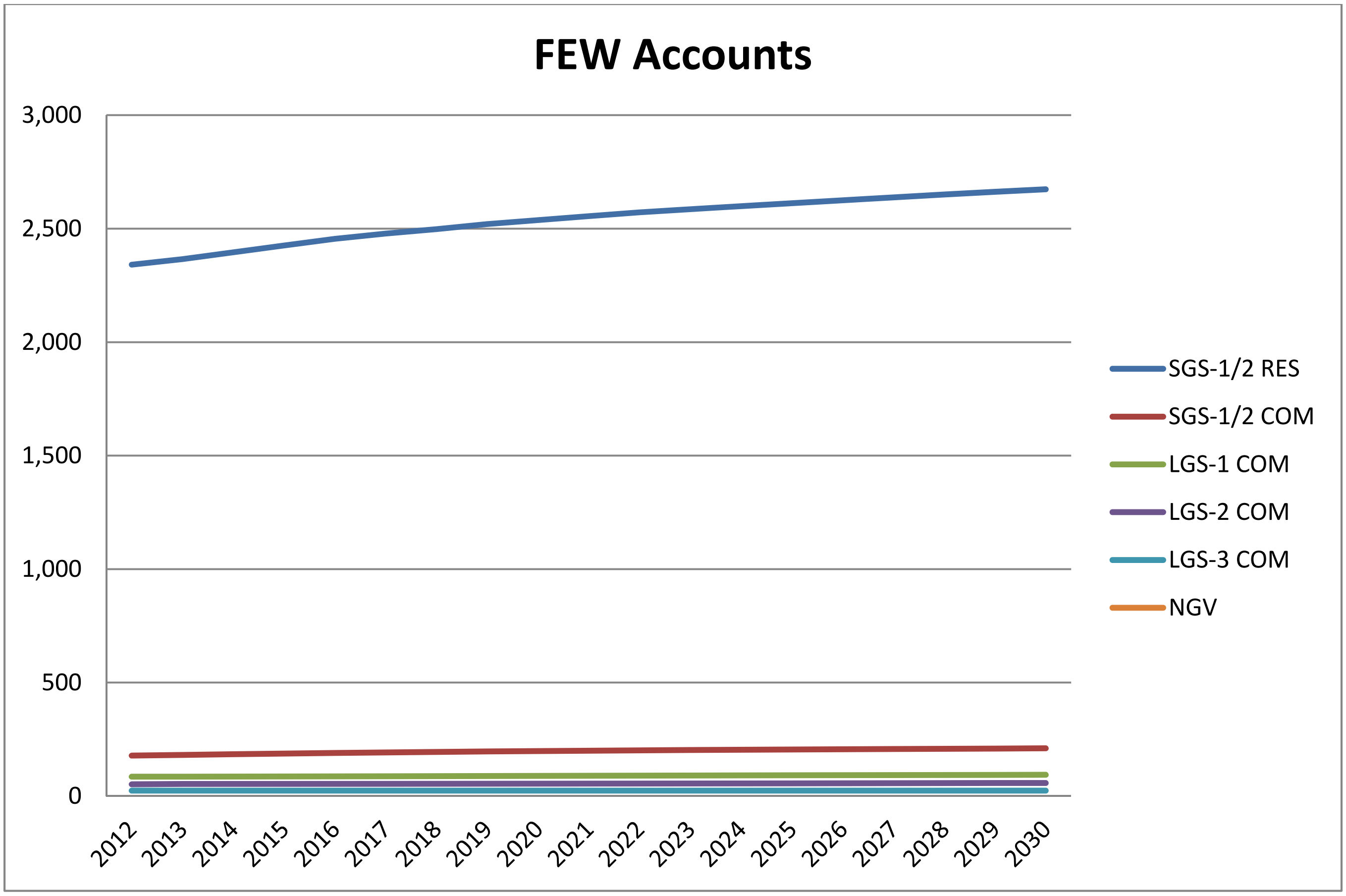
FEW

Year end accounts by Rate Class

Rate Class	2023	2024	2025	2026	2027	2028	2029	2030
SGS-1/2 RES	2,586	2,599	2,612	2,624	2,638	2,650	2,662	2,673
SGS-1/2 COM	203	204	205	206	207	208	209	210
LGS-1 COM	90	91	91	92	92	93	93	94
LGS-2 COM	55	55	56	56	56	56	57	57
LGS-3 COM	24	24	24	24	24	24	24	24
NGV								

Annual Demand by Rate Class(TJ)

Rate Class	2023	2024	2025	2026	2027	2028	2029	2030
SGS-1/2 RES	213	214	215	216	217	218	219	220
SGS-1/2 COM	51	51	51	52	52	52	52	53
LGS-1 COM	107	108	108	109	109	110	110	111
LGS-2 COM	135	135	137	137	137	137	139	139
LGS-3 COM	220	220	220	220	220	220	220	220
NGV	0	0	0	0	0	0	0	0


FEW Accounts
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1,000
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2012
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2021
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2025
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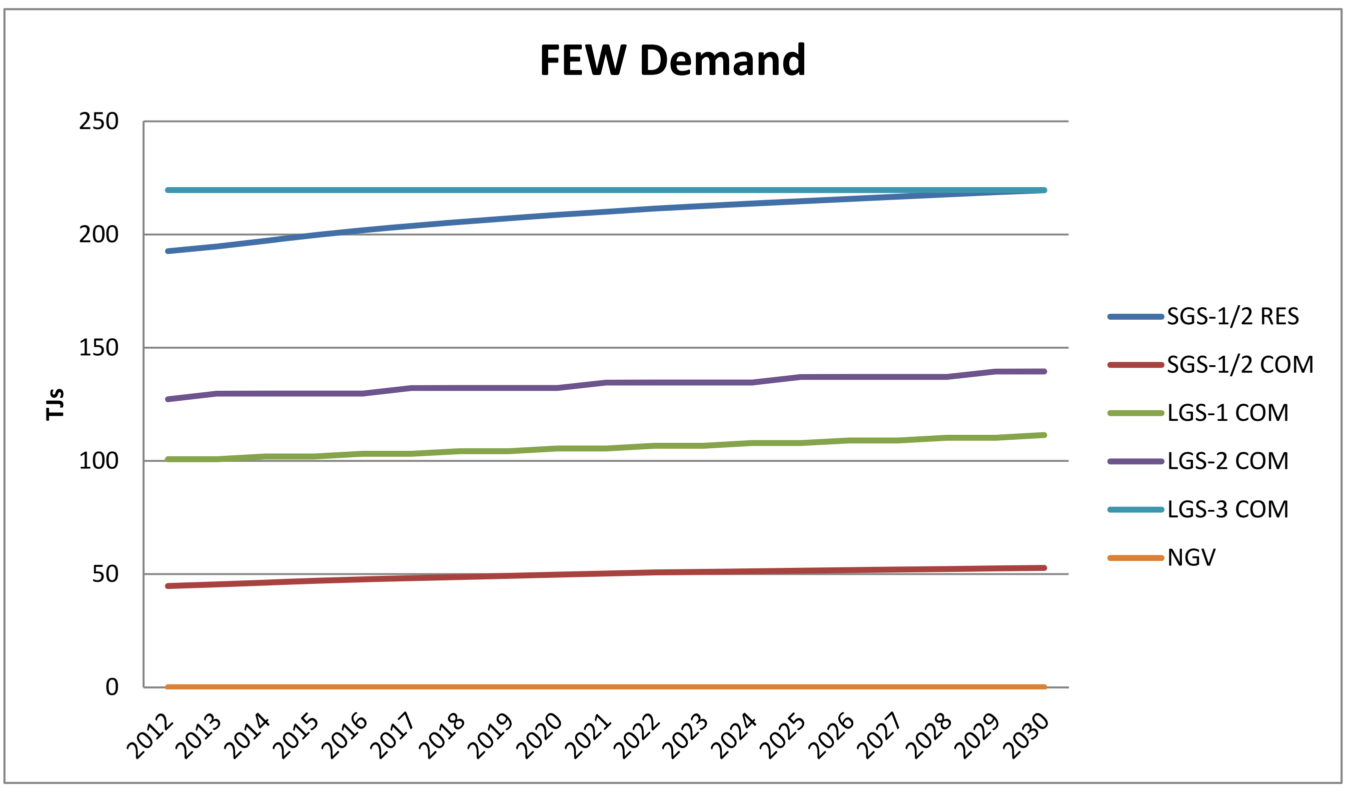
2027
2028
2029
2030
SGS-1/2 RES
SGS-1/2 COM
LGS-1 COM
LGS-2 COM
LGS-3 COM
NGV


FEW Demand
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150
100
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TJs
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2029
2030
SGS-1/2 RES
SGS-1/2 COM
LGS-1 COM
LGS-2 COM
LGS-3 COM
NGV

FEFN

YE Accounts by rate class

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate 1	1,951	1,957	1,963	1,968	1,973	1,976	1,980	1,983	1,988	1,992	1,997
Rate 2(2_1)	419	421	423	425	427	428	429	430	432	434	436
Rate 3(2_2)	28	28	28	28	28	28	28	28	28	28	28
Rate 4	0	0	0	0	0	0	0	0	0	0	0
Rate 5	0	0	0	0	0	0	0	0	0	0	0
Rate 6	0	0	0	0	0	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0	0	0	0	0	0
Rate 22	0	0	0	0	0	0	0	0	0	0	0
Rate 23	0	0	0	0	0	0	0	0	0	0	0
Rate 25	2	2	2	2	2	2	2	2	2	2	2
Rate 27	0	0	0	0	0	0	0	0	0	0	0
Total -Transportation & IT	2	2	2	2	2	2	2	2	2	2	2
Total	2,400	2,408	2,416	2,423	2,430	2,434	2,439	2,443	2,450	2,456	2,463

Annual Demand by Rate Class(TJ)

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate 1	263	262	261	261	260	260	259	259	259	258	258
Rate 2	191	192	191	191	191	190	190	189	189	189	189
Rate 3	94	94	94	94	94	94	94	94	94	94	94
Rate 4	0	0	0	0	0	0	0	0	0	0	0
Rate 5	0	0	0	0	0	0	0	0	0	0	0
Rate 6	0	0	0	0	0	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0	0	0	0	0	0
Rate 22	0	0	0	0	0	0	0	0	0	0	0
Rate 23	0	0	0	0	0	0	0	0	0	0	0
Rate 25	50	50	50	50	50	50	50	50	50	50	50
Rate 27	0	0	0	0	0	0	0	0	0	0	0
Total	**599**	**598**	**597**	**596**	**595**	**594**	**593**	**592**	**592**	**592**	**591**

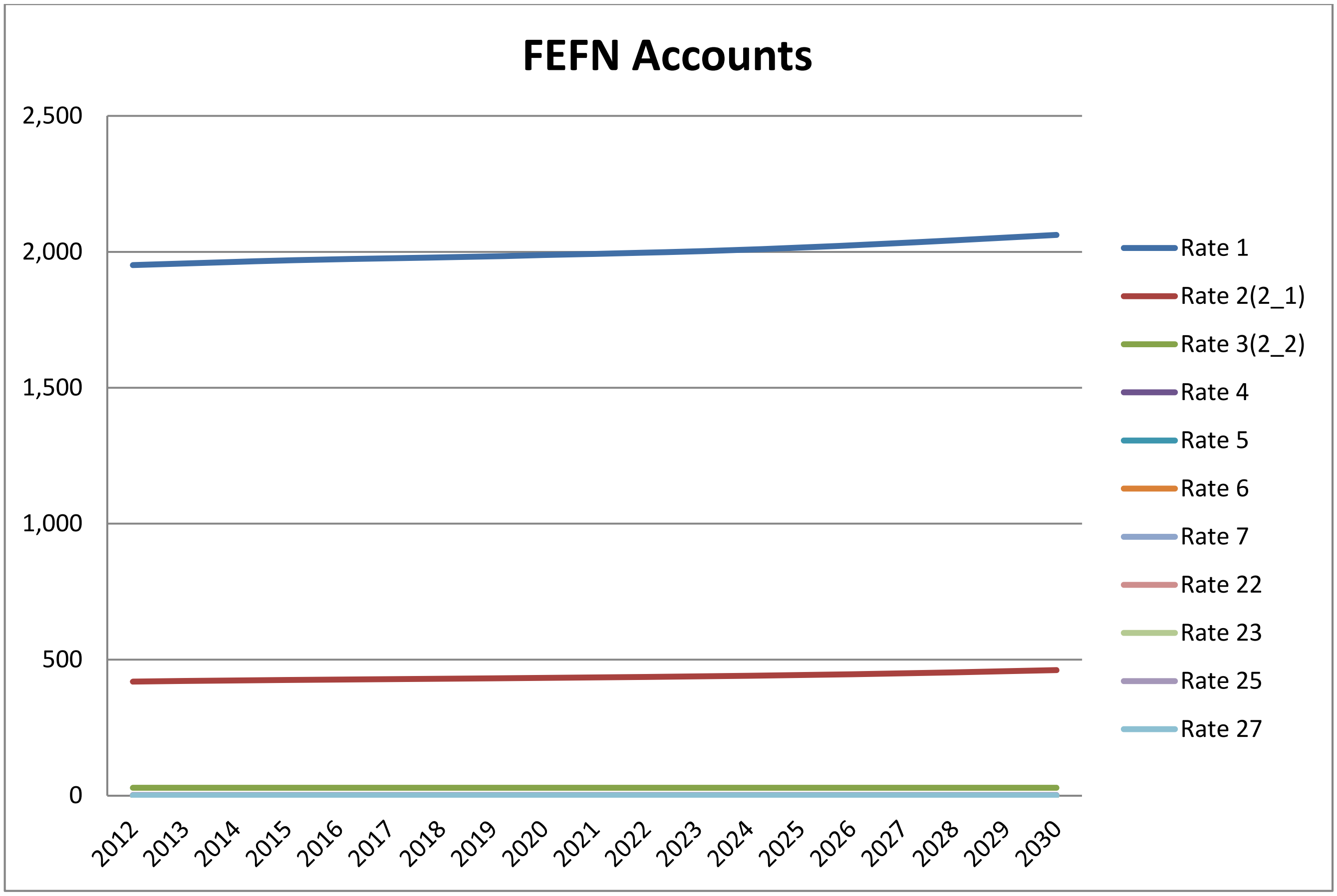
FEFN

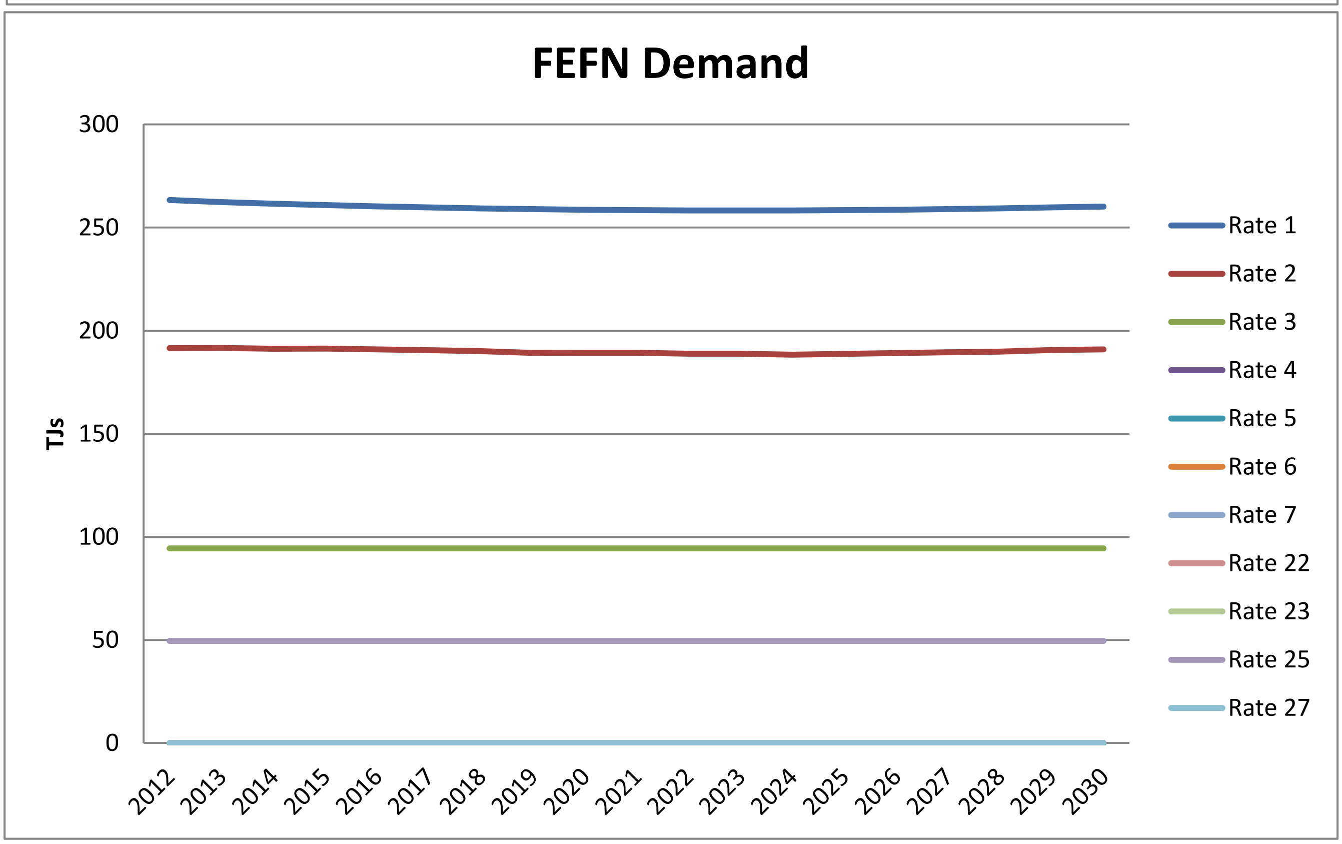
YE Accounts by rate class

Core	2023	2024	2025	2026	2027	2028	2029	2030
Rate 1	2,002	2,008	2,015	2,023	2,033	2,042	2,052	2,062
Rate 2(2_1)	438	440	443	446	450	453	457	461
Rate 3(2_2)	28	28	28	28	28	28	28	28
Rate 4	0	0	0	0	0	0	0	0
Rate 5	0	0	0	0	0	0	0	0
Rate 6	0	0	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0	0	0
Rate 22	0	0	0	0	0	0	0	0
Rate 23	0	0	0	0	0	0	0	0
Rate 25	2	2	2	2	2	2	2	2
Rate 27	0	0	0	0	0	0	0	0
Total -Transportation & IT	2	2	2	2	2	2	2	2
Total	2,470	2,478	2,488	2,499	2,513	2,525	2,539	2,553

Annual Demand by Rate Class(TJ)

Core	2023	2024	2025	2026	2027	2028	2029	2030
Rate 1	258	258	258	258	259	259	260	260
Rate 2	189	188	189	189	189	190	191	191
Rate 3	94	94	94	94	94	94	94	94
Rate 4	0	0	0	0	0	0	0	0
Rate 5	0	0	0	0	0	0	0	0
Rate 6	0	0	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0	0	0
Rate 22	0	0	0	0	0	0	0	0
Rate 23	0	0	0	0	0	0	0	0
Rate 25	50	50	50	50	50	50	50	50
Rate 27	0	0	0	0	0	0	0	0
Total	**591**	**590**	**591**	**592**	**592**	**593**	**594**	**595**


FEFN Accounts
2,500
2,000
1,500
1,000
500
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Rate 1
Rate 2(2_1)
Rate 3(2_2)
Rate 4
Rate 5
Rate 6
Rate 7
Rate 22
Rate 23
Rate 25
Rate 27


FEFN Demand
TJs
300
250
200
150
100
50
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Rate 1
Rate 2
Rate 3
Rate 4
Rate 5
Rate 6
Rate 7
Rate 22
Rate 23
Rate 25
Rate 27

Attachment 47.1

	Regulatory Framework	Ability to Recover Costs and Earn Returns	Diversification /Market Position	Liquidity	CFO Interest Coverage	CFO to Debt	CFO-Dividends to Debt	Debt/Capital
AGL Resources Inc.	Baa	Baa	A/Baa	Baa	A	Baa	Baa	Baa
Alliant Energy Corp.	A	A	Baa	Baa	Aa	A	A	A
Atmos Energy Corp.	Baa	Baa	A	Baa	A	A	A	A
Consolidated Edison	Baa	Baa	A	A	Baa	Baa	Baa	Baa
Integrys Energy Group Inc.	Baa	Baa	Baa/A	Baa	A	A	A	A
Northwest Natural Gas	Baa	A	A	Ba	Baa	Baa	Baa	Baa
Piedmont Natural Gas	A	A	A	Baa	Aa	A	A	A
Southern Company	A	A	Ba/A	A	A	Baa	Baa	Baa
Vectren Corp.	Baa	A	Baa	Baa	A	A	A	A
WGL Holdings Inc.	Baa	A	A	A	Aa	A	A	A
Wisconsin Energy Corp.	A	A	Baa	Baa	A	Baa	A	Baa
Xcel Energy Inc.	Baa	A	A	Baa	A	A	A	Baa

Attachment 47.2

(Provided in electronic format only due to
document size and in order to conserve paper)

Global Credit Research
Credit Opinion
14 DEC 2011

Credit Opinion: AGL Resources Inc.

AGL Resources Inc.

Atlanta, Georgia, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Senior Unsecured Shelf	(P)Baa1
Jr Subordinate	Baa2
Pref. Shelf	(P)Baa3
AGL Capital Corporation	
Outlook	Stable
Bkd Senior Unsecured	Baa1
Jr Subordinate	Baa2
Bkd Commercial Paper	P-2
AGL Capital Trust III	
Outlook	Stable
BACKED Pref. Shelf	(P)Baa2
Atlanta Gas Light Company	
Outlook	Stable
Senior Unsecured	A3
AGL Capital Trust II	
Outlook	Stable
BACKED Pref. Shelf	(P)Baa2

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Key Indicators

[1]
AGL Resources Inc.

	LTM (09/11)	2010	2009	2008	2007
(CFO Pre-W/C + Interest) / Interest Expense	**5.3x**	**5.3x**	**5.6x**	**4.8x**	**3.8x**
(CFO Pre-W/C) / Debt	**18.8%**	**17.2%**	**19.0%**	**16.5%**	**15.4%**
(CFO Pre-W/C - Dividends) / Debt	**13.8%**	**12.0%**	**13.9%**	**11.2%**	**9.5%**
Debt / Book Capitalization	**52.4%**	**54.0%**	**53.5%**	**56.3%**	**52.0%**

[1] All ratios calculated in accordance with the Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

- Nicor acquisition credit neutral

- Generally constructive regulatory jurisdictions

- Non-utility businesses facing headwinds

Corporate Profile

Headquartered in Atlanta, Georgia, AGL Resources Inc. (AGL; Baa1 senior unsecured, stable outlook) is an energy services holding company. On December 9, 2011, AGL acquired Nicor Inc. in a transaction with a enterprise value of almost $3 billion. The combined company consists primarily of seven local gas distribution companies (LDCs) in Illinois, Georgia, New Jersey, Tennessee, Virginia, Florida, and Maryland, which collectively serve over 4 million retail customers. The largest of these utilities are the newly acquired Northern Illinois Gas Company (Nicor Gas, A3 issuer rating, the principal subsidiary of Nicor Inc.), followed by Atlanta Gas Light Company (A3 senior unsecured, the principal legacy utility of AGL). AGL's unregulated operations businesses include its retail energy operations, wholesale energy services, containerized shipping, and gas storage development.

SUMMARY RATING RATIONALE

AGL's Baa1 senior unsecured rating reflects the stable cash flow and low business risk profile of the regulated gas utilities that make up the majority of the company, regulatory and market diversity, and solid credit metrics. The rating also reflects the higher business risk of its unregulated operations

DETAILED RATING CONSIDERATIONS

NICOR ACQUISITION CREDIT NEUTRAL

AGL financed its acquisition of Nicor Inc.'s stock, valued at roughly $2.5 billion, with cash and common stock. The transaction was bondholder-friendly in that about 60% was with common stock. The $975 million of acquisition debt that AGL incurred represents about an 80% increase from pre-acquisition debt, but this is offset by about the same proportional increase in cash flow before working capital (CF pre-w/c) from Nicor, based on the LTM 9/11. Because Nicor's CF pre-w/c-to-debt ratio (48% as of LTM 9/11) was more than twice as strong as AGL's, AGL's post-merger CF pre-w/c-to-debt ratios remain unchanged from its pre-merger level of 21%. The significant amount of equity financing also mitigates the upcoming costs of integrating Nicor as well as reduced revenues from some of its non-utility businesses.

GENERALLY CONSTRUCTIVE REGULATORY JURISDICTIONS

LDCs comprise AGL's largest segment, and their rate-regulation lends stability to the company's credit profile. These operations are somewhat diversified, and Moody's considers the company's regulatory environment overall to be average from a credit perspective, mostly due to the above-average treatment in Georgia (34% of the combined rate base) and Virginia (12% of the combined rate base) balanced by more average treatment in its other jurisdictions in Illinois (36% of rate base), New Jersey (12%), Florida (4%), Tennessee (2%), and Maryland (under 1%).

AGL's LDCs have limited exposure to commodity price, weather, and volume volatility due to margin-stabilizing rate mechanisms such as decoupling, straight-fixed-variable rates, and weather normalization. While the LDCs may experience some notable, but temporary, shifts in cash flow and debt metrics during a period of rapidly changing gas costs, these costs are recovered in a timely manner under purchased gas adjustment mechanisms. The company also has infrastructure recovery clauses in some of its larger jurisdictions (Georgia, New Jersey, Virginia).

AGL's ratings are based on its current and future rate cases being at least credit-neutral. Virginia Natural Gas has a pending rate case, requesting a $25 million rate increase, which is expected to concluded in the first half of 2012.

NON-UTILITY BUSINESSES FACING HEADWINDS

AGL's non-utility businesses - in particular, the wholesale energy marketing (gas transportation and storage services to large industrial customers), gas storage development, and containerized shipping - are all riskier than the core LDC business. Although these activities have established track records, they have all been hit by the cyclical downturn in demand which is not likely to ease, at least, for a few years. The shipping business came with the Nicor acquisition, and we do not believe it will be core for AGL over the long term.

With shale gas production surging, flat basis differentials and low seasonal spreads are weighing on the company's marketing and storage businesses. Containerized shipping, historically a cash generator even in recessionary times, has experienced net operating losses for the first time in recent memory due to volumes declines.

Credit Profile of Significant Subsidiaries

AGL manages the funding for its subsidiaries through a corporate money pool. Short- and long-term borrowings are centralized at AGL Capital, the company's guaranteed financing vehicle. With over 70% of debt at the parent level, structural subordination is far less than in typical utility corporate structures. These factors support the close notching among the ratings of the utility subsidiaries and the holding company.

Atlanta Gas Light Company's (AGLC, 34% of AGL/Nicor's combined pro-forma operating income as of LTM 9/11) A3 senior unsecured rating indicates its sound credit metrics, low business risk, constructive regulatory environment in Georgia, and limited exposure to commodity prices, weather, and volume volatility. AGLC's rating also reflects the implicit burden of approximately $2.6 billion of holding company-level debt pro forma for the Nicor transaction. Other than about $200 million of external debt, AGLC's debt consists of intercompany borrowings, another reason for the close alignment of its rating with AGL's. AGLC's credit metrics are stable. In fiscal 2010, CF pre-w/c-to- debt ratio was 22% and CF pre-w/c to interest ratio was 4.3 times, based on unaudited financial information.

Pivotal Utility Holdings' unenhanced senior unsecured rating of A3 for $40 million of industrial revenue bonds reflects its stability as a rate-regulated gas distributor in three generally constructive jurisdictions, sound credit metrics, and its participation in AGL's regulated money pool. Pivotal Utility Holdings accounted for 11% of AGL/Nicor's pro-forma combined operating income in the LTM 9/11 period. In terms of rate base, Elizabethtown Gas in New Jersey makes up about 75% of Pivotal's rate base with Florida City Gas in Florida accounting for most of the rest plus a nominal amount at Elkton Gas in Maryland. Pivotal Utility Holdings' recent ratios (CF pre-w/c-to-debt of 15% and CF pre-w/c to interest of 5.2 times in fiscal 2010) have shown some cyclical weakness, but its credit profile gets a lift from being part of AGL's LDC system.

Please refer to a separate credit opinion for Nicor Gas.

Liquidity

AGL has an adequate liquidity profile. AGL has a $1.3 billion credit facility at its guaranteed AGL Capital finance subsidiary. This facility expires in November 2016. The company is not required to represent and warrant regarding material adverse effects in financial position, litigation, and environmental compliance. AGL maintains ample headroom under the facility's 70% debt/capitalization covenant. Nicor Gas expects soon to implement a $700 million five-year credit facility with similar terms as AGL Capital's. Both of these credit facilities are intended to serve as backup for these companies' respective commercial paper programs. Refinancing risk is not significant in 2012 with only $15 million of notes coming due at AGLC between June and July.

Rating Outlook

The stable rating outlook anticipates that AGL will sustain consolidated cash flow before working capital changes (CF pre-w/c)-to-debt in the high 4 times range and CF pre-w/c-to-debt in the high teens.

What Could Change the Rating - Up

Over the next few years, Moody's does not foresee upward rating pressure for AGL, given the expected costs to integrate Nicor and weak industry fundamentals for its unregulated businesses.

What Could Change the Rating - Down

The ratings could be downgraded if the challenges of the Nicor integration and the pressures in the unregulated businesses prove more than expected, so that AGL's consolidated CF pre-w/c-to-interest falls sustainably to the mid 4 times range and CF pre-w/c-to-interest to the mid teens.

Rating Factors

AGL Resources Inc.

Regulated Electric and Gas Utilities Industry [1][2]	**ProForma LTM 9/30/2011**		**Moody's 12-18 month Forward View* As of December 13, 2011**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework				
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (5%)		Baa		Baa
b) Generation and Fuel Diversity (5%)		A		A
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	4.9x	A	4.5-5.0x	A

c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	21.4%	Baa	16-22%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	14.2%	Baa	12-15%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	50.0%	Baa	49-52%	Baa
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER AND INCORPORATES THE NICOR ACQUISITION

[1] All ratios are calculated using Moody's Standard Adjustments. [2] Proforma as of 9/30/2011(L); Includes the Nicor acquisition

Global Credit Research
Credit Opinion
30 SEP 2011

Credit Opinion: Alliant Energy Corporation

Alliant Energy Corporation

Madison, Wisconsin, United States

Ratings

Category	**Moody's Rating**
Outlook	Negative
Issuer Rating	Baa1
Senior Unsecured	Baa1
Commercial Paper	P-2
Wisconsin Power and Light Company	
Outlook	Negative
Issuer Rating	A2
Sr Unsec Bank Credit Facility	A2
Senior Unsecured	A2
Pref. Stock	Baa1
Commercial Paper	P-1
Interstate Power and Light Company	
Outlook	Negative
Issuer Rating	A3
Senior Unsecured	A3
Pref. Stock	Baa2
Commercial Paper	P-2
Interstate Power Company	
Outlook	Stable
Issuer Rating	A3
BACKED Pref. Shelf	(P)Baa2

Contacts

Analyst	**Phone**
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Key Indicators

[1]
Alliant Energy Corporation

	LTM 6/31/2011	**2010**	**2009**	**2008**
(CFO Pre-W/C + Interest) / Interest Expense	**6.5x**	**6.1x**	**7.0x**	**5.9x**
(CFO Pre-W/C) / Debt	**29%**	**25%**	**28%**	**21%**
(CFO Pre-W/C - Dividends) / Debt	**22%**	**19%**	**22%**	**15%**
Debt / Book Capitalization	**40%**	**41%**	**42%**	**41%**

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

- Non-material exposure to unregulated operations

- Utilities operate in above average credit supportive regulatory environments

- Geographic diversification underpinned by service territories in three States

- Utilities' industrial exposure can create potential cash flow volatility

- Weakening in credit metrics amid increased leverage to fund utilities' large capex program

Corporate Profile

Headquartered in Madison, Alliant Energy Corp (Alliant; Baa1, negative) is the parent company of the vertically integrated utilities, Interstate Power and Light (IPL; A3, negative) and Wisconsin Power and Light (WPL; A2, negative). Through WPL the company also holds a 16% ownership-interest in American Transmission Company (ATC; A1, stable).

WPL's operations are subject to the regulatory purview of the Public Service Commission of Wisconsin (PSCW), while IPL is exposed to the regulatory overview of the Iowa Utilities Board (IUB) and the Minnesota Public Utility Commission (MPUC). WPL, IPL and ATC are also subject to the regulatory jurisdiction of the Federal Energy Regulatory Commission (FERC).

Alliant's intermediate holding-company, Alliant Energy Resources (Resources), holds its unregulated businesses which consist mainly of renewable consulting services (RTM), as well as a Midwest-based transportation business and non-regulated generation units. The later includes the 300MW natural gas-fired Sheboygan Falls Energy Facility that is leased to WPL until 2025 and the 100MW Franklin County wind farm (total capex: $250 million) that Alliant is currently constructing.

As of June 30, 2011, Alliant had consolidated assets totaling $9.3billion, and recorded last twelve-month FFO of around $949million.

For more information on WPL and IPL as well as our assessment of the regulatory environments in their service territories, ongoing rate cases and investment programs, please refer to their Credit Opinions dated September 2011 which can be found on www.moodys.com.

SUMMARY RATING RATIONALE

Alliant's Baa1 senior unsecured rating is largely driven by the predominantly rate regulated nature of the group's business activities following the divesture of several non-regulated investments that were accumulated while previously pursuing a global strategy. The rating also considers Alliant's consolidated financial profile amid the increased leverage expected to be incurred by its operating utility subsidiaries to fund their capital expenditure (capex) programs. The Baa1 rating also considers the structural subordination that exists for parent level debt holders (around 13% of the consolidated indebtedness) relative to the subsidiaries' existing debt.

DETAILED RATING CONSIDERATIONS

NO MATERIAL EXPOSURE TO UNREGULATED OPERATIONS

Alliant's rating reflects the group's limited exposure to non-regulated businesses which account for less than 10% of the consolidated assets and revenues the bulk of which is generated by RMT. We note that currently no debt is associated with any of these unregulated businesses, they have modest capital requirements (around $10 million p.a.) and provide little in the way of current contributions. We anticipate Alliant will incur indebtedness to fund the Franklin County wind farm (remaining capex: US$135 million) with the expectation that Power Purchase Agreements (PPA) will be executed with creditworthy entities upon completion before the end of 2012.

ABOVE AVERAGE CREDIT SUPPORTIVE REGULATORY ENVIRONMENTS

Moody's ranks the regulatory environments in Wisconsin, Iowa and Minnesota only after the FERC's regulatory framework in terms of credit supportiveness and the ability to recover costs and generate returns on a timely basis. A number of regulatory features in these jurisdictions support our opinion, albeit last rate cases have raised some concerns, particularly, in Iowa and Minnesota. For more detail about the recent rate case outcomes refer to the utilities' Credit Opinions.

UTILITIES' LARGE CAPEX PROGRAM

Alliant plans to invest up to $2.8 billion between 2011 and 2013 (peak in 2013: $1.2 billion). Maintenance capital expenditure (capex) accounts for almost 50% of the 2011-2013 aggregate amount. The remainder is largely associated with WPL's expected acquisition of the Riverside natural gas plant (around $380 million), the construction of the Franklin County wind farm (remaining investments of around $100 million), and environmental related capital outlays to comply with the Federal and State regulations such as the EPA's Cross-State Air Pollution Rule (CASPR) issued in July, the National Emission Standards from Hazardous Air Pollutants Rules or the 316(b) cooling water intake structure.

Alliant has split its utilities' coal-fired fleet in three groups. With the first group, IPL and WPL will retire its older less efficient coal-fired units (total around 220MW installed capacity; book value around $25 million) by 2015 after obtaining the regulatory approvals and pending MISO's reliability issues. The second group consists of those plants that warrant the installation of emission control equipment by 2014 (around 2,100MW installed capacity; book value: around $600 million) and will account for around $805 million of investments.

Alliant's ongoing cost-benefits analysis is focused on the third group of plants to determine on a case-by-case basis whether to install emission control equipment or retire them. These plants approximate 940MW (book value: $335 million). The aggregate capex mentioned above includes possible environmental investments associated with these facilities as well as some discretionary spending to improve the fleet's overall efficiency. We do not believe that actual capex will exceed the group's publicly disclosed projected capital outlays and that the operations of the Alliant's subsidiaries will not be any worse off than other Midwest utilities trying to recover additional environmental related costs through increased rates.

IPL may not renew its Power Purchase Agreement (PPA) with NextEra's DAEC nuclear plant after its scheduled expiration in 2014. To replace that load IPL is considering the construction of a 600MW natural gas fired plant by 2016 (estimated capex up to $750 million; spending likely to start in 2014). The construction of this plant was previously deferred after IPL reassessed its power requirements in the wake of the recent economic downturn, and after two large customers completed their own cogeneration facilities during 2009.

GEOGRAPHICAL DIVERSIFICATION BUT SIGNIFICANT INDUSTRIAL CUSTOMER EXPOSURE AND LIMITED FUEL DIVERSITY

The group's operations in electric and natural gas in three different states underpin our assessment of Alliant's diversification factor in the grid below. Nevertheless, we also note IPL's and WPL's significant reliance on their industrial customer base which accounts for 40% and 30%, respectively, of their total electric sales which makes them particularly vulnerable to economic downturns.

CREDIT METRICS LIKELY TO WEAKEN OVER THE NEAR TERM

Historically, Alliant's credit metrics have been strong for the rating category. Specifically, its 2008-2010 ratio of CFO pre-W/C to debt, CFO pre-W/C interest coverage and RCF to debt averaged about 26.1%, 6.3x and 17.3%, respectively. Prospectively, Alliant's consolidated credit metrics are likely to weaken given the expected deterioration in IPL's and WPL's credit metrics and our anticipation that the holding company will incur additional debt to fund its remaining investments in the Franklin County wind farm as well as anticipated equity contributions to both utilities over the next several years in support of their capital programs. However, we do not anticipate Alliant's parent only debt to account for more than 15% of the consolidated debt. WPL and IPL are expected to sustain a dividend payout ratio up to 70% despite the substantial planned capex program while also maintaining a common equity ratio of at least 45% over the medium term. Moody's does expect Alliant to issue any equity through 2013. While there is some cushion in the rating near term, consolidated credit metrics are clearly expected deteriorate over the medium term.

Liquidity

Alliant's Pirme-2 short-term rating for commercial paper (CP) reflects Moody's view that the issuer will maintain adequate liquidity over the next four quarters.

Alliant plans no issuance of long-term debt for the group this year (albeit this depends upon market conditions), and to fund the group's 2011 capex (around $700 million) and dividend distributions largely with internally generated funds. Following the redemption of $40.4 million of IPL's cumulative preferred stock in April 2011, the group has no significant debt maturing before 2014 when Alliant's $250 million senior notes become due.

During the first half of 2011, Alliant made total equity capital contributions of $25 and $65 million to WPL and Resources, respectively, while it received around $171 million in the form of dividend distributions from the utilities (WPL: $56 million; IPL: $44 million) and capital repayments from IPL ($71 million). The later is associated with the sale of its transmission assets.

At the end of June 2011 and December 2010, no amounts were outstanding under Alliant's CP program which is back-stopped by its $96 million unsecured credit facility that expires in November 2012 (fully available at end of June). This facility does not have a material adverse change clause and the sole financial covenant is a 65% limitation on the debt component of Alliant's capital structure (June 30, 2011: 46%); however, it includes a cross-default provision that is triggered if one of Alliant's domestic subsidiaries defaults on debt of $50 million or larger. Moody's expects that Alliant and its subsidiaries will renew their committed credit facilities well ahead of their expiration next November with a possible increase in size given the substantial planned capex.

Rating Outlook

Alliant's negative outlook reflects the negative outlook of its two utility subsidiaries and the expected weakening in consolidated metrics.

What Could Change the Rating - Up

In light of the fact that credit metrics are anticipated to weaken, limited prospects exist for an upgrade over the medium term.

What Could Change the Rating - Down

Alliant's ratings are likely to be downgraded following a downward movement in its subsidiaries' ratings given the structural subordination embedded in Alliant's ratings. The ratings could be downgraded if the key credit metrics show a significant deterioration due to heavy capital expenditures, a continued weakening in the local economies, or a deterioration in the regulatory environment with less favorable decisions such that Alliant's reported CFO pre W/C to adjusted debt declines to below 18% and/or the CFO pre W/C interest coverage falls below 3.5x for an extended period.

Other Considerations

Moody's evaluates IPL's financial performance relative to the Regulated Electric and Gas Utilities rating methodology. As depicted in the grid below, the company's indicated rating based on historical and projected credit metrics is A3 and Baa1, respectively.

Rating Factors

Alliant Energy Corporation

Regulated Electric and Gas Utilities Industry [1][2]	**Current 12/31/2010**		**Moody's 12-18 month Forward View* As of June 2011**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		A		A
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (5%)		Baa		Baa
b) Generation and Fuel Diversity (5%)		Baa		Baa
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	6.4x	Aa	4.5-5.5x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	24.8%	A	20-22%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	18.7%	A	12-17%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	41.3%	A	40-45%	A
Rating:				
a) Indicated Rating from Grid		A3		Baa1
b) Actual Rating Assigned		Baa1		Baa1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2010(L); Source: Moody's Financial Metrics

AND EVALUATION OF EACH SECURITY THAT IS UNDER CONSIDERATION FOR PURCHASE, HOLDING, OR SALE.

Moody's Investors Service

Global Credit Research
Credit Opinion
8 MAY 2012

Credit Opinion: Atmos Energy Corporation

Atmos Energy Corporation

Dallas, Texas, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Senior Unsecured	Baa1
Subordinate Shelf	(P)Baa2
Bkd Commercial Paper	P-2

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Opinion

Rating Drivers

- Successful ongoing rate activity in constructive regulatory jurisdictions

- Stable rate-regulated operations

- Sustained strength in financial performance

Corporate Profile

Atmos Energy Corporation (Atmos or AEC; Baa1 senior unsecured) is primarily engaged in regulated natural gas distribution in twelve states (Texas, Louisiana, Mississippi, Kentucky, Tennessee, Kansas, Colorado, Georgia, Illinois, Missouri, Virginia, and Iowa) and transmission and storage in Texas. Atmos has an intermediate holding company Atmos Energy Holdings, Inc. (AEH) that owns non-utility subsidiaries engaged principally in gas marketing, housed at its Atmos Energy Marketing, LLC (AEM) subsidiary, as well as minor pipeline and storage operations in Louisiana and Kentucky.

By year-end September 2012, Atmos will sell its natural gas distribution operations in Missouri, Illinois and Iowa, three service areas where it has limited operations. The sale is credit-positive in generating $124 million in proceeds, which the company can use toward its active capital program and reduce the amount of debt it would otherwise have to incur. Meanwhile, earnings reduction from the sale will be modest, since the company will lose only a small number of customers.

SUMMARY RATING RATIONALE

Atmos's ratings are supported by the low risk of its rate-regulated gas distribution utilities in generally constructive regulatory jurisdictions, a good record as a gas distributor, reasonable leverage, and a conservative management approach. Gas marketing is the riskiest element of the company, but it is expected to be a small, shrinking part of Atmos.

DETAILED RATING CONSIDERATIONS

- Successful ongoing rate activity in constructive regulatory jurisdictions

With distribution and pipeline operations in twelve states, Atmos has jurisdictional diversity that reduces its exposure to any one adverse regulatory decision or warmer-than-normal weather in any of its service territories. It does have some asset concentration in Texas (59% of customer meters). Next largest service areas are Louisiana (11% of meters) and Mississippi (9%). The regulatory frameworks in these states are credit-supportive, with Texas and Louisiana utilities generally scored as Baa in Factor 1 under Moody's regulated utilities rating methodology and Mississippi scored as A. Further regulatory diversity results from the many municipalities that hold original jurisdictions in Texas as well as separate ratemaking for pipelines in Texas and Louisiana.

Atmos has been successful in increasing and stabilizing its regulated margins through rate increases and rate design improvements. Given its disparate operations and rising costs, regulatory lag is an issue that Atmos addresses through numerous and continual rate activity, including regular rate adjustments, outside of base rate cases, for small amounts spread over its many jurisdictions. Such mechanisms increase the certainty of obtaining some timely rate relief while reducing the company's exposure to an adverse rate decision. However, Atmos needs many such small increases to affect margins materially. Over the last four years, about 20% of these operating income increases from rate activity has come from the Gas Reliability Infrastructure Program (GRIP) filings in Texas, which allows Atmos to recover capital investments made the prior year without a rate case. In addition, the company has obtained rate design changes that mitigate earnings volatility from weather and lower consumption (covering over 90% of its meters) and bad debts (covering over two thirds of its meters).

- Stable rate-regulated operations

Being predominantly regulated, AEC has low business risk, with core rate-regulated distribution in numerous states and a tariff-based pipeline in Texas (mostly serving its affiliate Mid-Tex) accounting for 79% and 9%, respectively, of consolidated 2011 gross profit. Of medium risk are the less predictable market-driven profits that the regulated and unregulated pipelines earn from providing transportation and ancillary services (12% of gross profit), mostly to third parties.

Gas marketing is Atmos's riskiest business, being exposed to commodity price, basis, counterparty, and other risks, which makes it difficult to predict its financial results with a high degree of accuracy. As a management strategy, AEC has been de-emphasizing unregulated operations in light of their weak medium-term outlook. In particular, AEM's asset optimization business has been suffering from reduced sales volumes as arbitrage opportunities on AEM's assets have dissipated in the current market environment. The drop in asset optimization profits has caused AEM's overall earnings to decline significantly in the last few quarters, and we do not anticipate a turnaround anytime soon. We have assumed very little earnings from this business.

By contrast, AEM's delivered gas business (a bundled gas service provided to longstanding utility, municipal, and industrial customers) has remained fairly consistent (4% of gross profit) and accounts for the vast majority of AEM's earnings.

- Sustained strength in financial performance

Over the years, Atmos has been accruing sufficient rate increases to sustain a modest but steady improvement in its credit metrics. In its fiscal year ended September 30, 2011, Atmos was approved for $72 million in annual rate increases (about 6% of the previous year's regulated gross profit). So far in fiscal 2012, Atmos has received about $23 million in rate relief and has pending some $69 million of rate requests.

Atmos's baseline cash flow from operations before working capital changes (CFO pre-WC) is in the low $600 million range ($621 million in the last twelve months ended March 2012), down from the $722 million in fiscal year 2010, which was boosted by a one-time change in accounting for repairs as well as bonus depreciation. Atmos's credit metrics currently map to the low A, high Baa range under Moody's regulated utilities rating grid. CFO pre-WC-to-debt is at or above 20% (22.6% in fiscal year 2011, 22.2% in the 12 months ended March 2012). CFO pre-WC plus interest-to-interest has remained in the high 4 times range (4.8x in both fiscal 2011 and the 12 months ended March 2012).

Liquidity Profile

Atmos will have adequate near-term liquidity assuming normal market conditions. As it is not unusual for a utility, Atmos is often in a negative free cash flow position. For the last four quarters ended March 31, 2012, cash flow from operations was $505 million with capital expenditures of $687 million and dividends of $125 million, resulting in negative free cash flow of $307 million. Additionally, AEC's has $250 million of senior notes coming due in January 2013, which we assume the company will be able to refinance with $350 million of notes as it plans.

Atmos has a $750 million committed facility, expiring on May 2, 2016, with an accordion feature for borrowing up to $1 billion. This facility sets a maximum debt-to-capitalization ratio at 70%, under which AEC has adequate headroom (52% at March 31, 2012). AEC also has a committed $25 million 364-day revolving credit facility with a local bank, which expires on March 31, 2013.

AEC's Prime-2 rated commercial paper program is fully backed by the above-mentioned $750 million credit facility. The value of this backup in case of an unforeseen market disruption, however, is weakened by the agreement's requirement for at least one day's notice prior to funding.

AEM has a committed $200 million three-year facility with an accordion feature to $500 million, that matures in December 2013. As of March 2012, Atmos had $82 million available under this credit facility. This facility is unconditionally guaranteed by AEH. The effective availability under the facility is a range of $100 to $200 million based on a borrowing base determined by tangible net worth, net working capital, and the value of the collateral. Availability will be limited also if AEC's ratings were to fall to Baa3 and below. AEM was in compliance with the maximum liabilities-to-net worth covenant of 5 times (0.97 times at March 31, 2012) and minimum net working capital and net tangible net worth of $20 to $40 million (working capital of $106 million and net worth of $143 million at March 31, 2012).

Atmos maintains separate liquidity facilities for AEC, AEH, and AEM. AEC extends an uncommitted credit line of $500 million to AEH.

Conversely, AEH provides a $500 million line to AEC.

Rating Outlook

The stable outlook is based on Atmos's low-risk, regulated activities that produce consistent financial performance and is subject to the company maintaining adequate liquidity resources. The rating assumes credit metrics sustained around current levels (for example, CFO pre-WC-to-debt in the low 20% range).

What Could Change the Rating - Up

The rating could be upgraded if the company were to demonstrate a sustained improvement in its credit metrics (for example, with CFO pre-WC-to-debt in the mid 20% range) while reducing exposure to unregulated activities and further strengthening its liquidity arrangements.

What Could Change the Rating - Down

A sustained weakening in Atmos' credit metrics (including CFO pre-WC-to-debt in the high teens) could cause the rating to be downgraded. In addition, M&A activity that results in higher financial and business risks could also negatively affect the rating.

Rating Factors

Atmos Energy Corporation

Regulated Electric and Gas Utilities [1][2]	**Last 12 months ended Mar 31, 2012**		**Moody's 12-18 month Forward View As of May 9, 2012***	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory framework		Baa		Baa
Factor 2: Ability to Recover Cost and Earn Returns (25%)				
a) Ability to recover Cost and Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position		A		A
b) Generation and Fuel Diversity		-		-
Factor 4: Financial Strength, Liquidity, & Metrics (40%)				
a) Liquidity		Baa		Baa
b) CFO (pre w/c) + Interest / Interest	4.8x	A	4.5x-5.5x	A
c) CFO (pre w/c) / Debt	22.2%	A	19%-24%	Baa
d) CFO (pre w/c) - Dividends / Debt	17.7%	A	14%-20%	Baa
e) Debt / Capitalization	45.0%	A	43%-48%	A
Rating:				
Indicated Rating from Grid		Baa1		Baa1
Actual Rating Assigned		Baa1		Baa1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] Source: Moody's Financial Metrics

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Global Credit Research
Credit Opinion
21 DEC 2011

Credit Opinion: **Consolidated Edison, Inc.**

Consolidated Edison, Inc.

New York City, New York, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured Shelf	(P)Baa1
Subordinate Shelf	(P)Baa2
Pref. Shelf	(P)Baa3
Commercial Paper	P-2
Consolidated Edison Company of New York, Inc.	
Outlook	Stable
Issuer Rating	A3
Senior Unsecured	A3
Subordinate Shelf	(P)Baa1
Pref. Stock	Baa2
Commercial Paper	P-2
Orange and Rockland Utilities, Inc.	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
Subordinate Shelf	(P)Baa2
Commercial Paper	P-2

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Key Indicators

[1]
Consolidated Edison, Inc.

	[2]**LTM**	**2010**	**2009**	**2008**	**2007**
CFO pre-WC + Interest/ Interest	**6.0x**	**4.8x**	**3.5x**	**3.7x**	**3.4x**
CFO pre-WC / Debt	**26.8%**	**20.6%**	**15.7%**	**12.2%**	**13.7%**
CFO pre-WC - Dividends / Debt	**21.7%**	**15.9%**	**11.1%**	**7.6%**	**7.8%**
Debt / Capitalization	**41.9%**	**43.1%**	**45.5%**	**48.3%**	**41.6%**

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments [2] Last twelve months ended September 30, 2011

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low-risk regulated transmission and distribution (T&D) utilities represent majority of operations

Challenging regulatory environment

Very attractive utility service territories in New York City area

Large scale helps to absorb stress

Credit metrics unsustainably high

Corporate Profile

Consolidated Edison, Inc. (CEI, Baa1 senior unsecured) is a holding company whose principal subsidiaries are regulated T&D utilities Consolidated Edison Company of New York, Inc. (CECONY, A3 senior unsecured) and Orange and Rockland Utilities, Inc. (O&R, Baa1 senior unsecured). These utilities comprise the largest utility system in New York State and serve roughly 3.6 million electric, 1.2 million gas and 1,760 steam customers in some of the state's most vital communities. Utility subsidiaries represent over 95% of CEI's operating income. The remaining 5% of operating income comes from unregulated subsidiaries that are engaged in the competitive wholesale and retail power supply businesses, which we expect will remain a small part of the company. The holding company has little debt, consisting of a single debt issue which is only 3% of consolidated long-term debt.

CECONY is the largest North American T&D utility we rate. It accounts for 90% of CEI's operating income and serves the vast majority of CEI's electric and gas and all of its steam customers in and around New York City and Westchester County. A much smaller subsidiary, O&R (about 5% of CEI's operating income) serves electric and gas customers in the New York City exurbs mostly in New York State but also in New Jersey and Pennsylvania.

CEI's Baa1 rating reflects the stable and predictable cash flows generated by the regulated T&D subsidiaries which comprise the vast majority of its operations. The T&D utilities have low business risk profiles given their limited exposure to volume risk and commodity price risk as well as the absence of any significant generation. CEI exhibits robust credit metrics which will help cushion its credit quality against regulatory challenges and contingent liabilities that may arise.

DETAILED RATING CONSIDERATIONS

LOW RISK REGULATED T&D UTILITIES REPRESENT MAJORITY OF OPERATIONS

CEI generates stable and predictable cash flows from its regulated T&D subsidiaries. Compared to vertically integrated utilities, T&D utilities have lower business risk related to commodity prices, because the cost of purchased power, gas and fuel are passed through to ratepayers. CEI's utilities also have limited volume risk exposure, since the majority of their operations benefit from revenue decoupling mechanisms and their gas operations benefit from weather normalization clauses. CECONY is exposed to volume risk and the operational risks associated with generation assets in its steam operations but this segment is only 3% of CECONY's operating income.

CHALLENGING REGULATORY ENVIRONMENT

The New York Public Service Commission (PSC) regulates effectively all of CECONY's electric, gas and steam operations and the majority of O&R's electricity and gas operations. The PSC is CEI's most influential regulator. On balance, Moody's views CEI's New York regulatory environment to be challenging.

On the positive side, the utilities benefit from three-year rate plans based on a future test year and decoupling (a true-up of revenue variations from weather and usage). Utilities pass through power and commodity costs to customers and fully recover costs related to pensions, OPEB and environmental remediation. True-up mechanisms permit assured recovery of all but a minor portion of property taxes and interest expense.

On the other hand, regulatory proceedings in the state have tended to be contentious and fully litigated. Although we focus on cash flow ratios in our credit ratings, we note the allowed ROEs in the state being lower than the US average as one indicator of a relatively restrictive regulatory environment.

Recent settlements have featured asymmetrical earnings sharing mechanisms which confer the majority of any over-earnings to the ratepayer while providing no downside protection to the utilities. Prudence reviews on various matters have not infrequently resulted in refunds to customers. Penalties are imposed if utilities fall short of customer service, reliability and safety targets.

CECONY would be required to refund customers to the extent that actual capital spending is less than that assumed in rates while any over-spending would earn no return and would have to be specifically justified in the next rate case before being included in rate base. In the case of CECONY's 2010 electric decision, any capital spending above the target levels in the first year of the rate plan, even if properly supported in a subsequent rate case, would only receive a debt return for the life of the asset(s) in question.

The predictability of the regulatory process and ability to recover costs are all the more important as CEI continues to spend about $2 billion a year, mostly for system replacement. This spending cycle has resulted in a series of rate cases (seven electric, three gas and two steam cases since 2007) with more on the horizon. Following a failure to agree on a 3-year electric rate plan in 2011, O&R is currently undergoing another rate case with the PSC with a request for a $18 million increase. During 2012, CEI may start rate proceedings in advance of the expiration of 3-year settlements for O&R gas rates (expiring in October 2012) and CECONY's electric rates (expiring March 2013) and gas/steam rates (expiring September 2013)

LARGE SCALE HELPS TO ABSORB STRESS

CEI's utility subsidiaries serve the New York City area which is a large and vibrant economic region. While the high population density, vast underground infrastructure and urban character of CECONY's service territory present especial operational challenges and expose the company to high levels of public and political scrutiny, we believe that this is more than offset by the size and relative stability of the region's economy. In light of CEI's large size and attractive franchise area, we believe that CEI has superior access to capital and better than average flexibility to manage through periods of stress.

Stress events could arise from CEI's various contingent liabilities, which could be significant if they materialize but should be manageable for a company with assets of over $36 billion. The largest contingencies include a dispute with the Internal Revenue Service (IRS) on tax deductions associated with two Lease In/Lease Out (LILO) transactions. CEI estimates that in the worst case, the cash impact of settling the LILO issue would be approximately $320 million as of September 30, 2011. Another is PSC's investigation of CECONY related to alleged kickbacks between certain former employees and contractors in 2009. About $753 million of the revenues that CECONY has collected as of September 2011 are subject to refund if CECONY is found liable. Other large contingencies stem from a steam pipe explosion in 2007, for which the company has not booked a reserve. In addition, CEI has undiscounted environmental costs that could range up to $2.1 billion which are fully recoverable under current ratemaking.

CREDIT METRICS UNSUSTAINABLY HIGH

CEI's financial performance reflects that of CECONY, its predominant subsidiary. CEI's financial metrics have been unsustainably high recently, because of the impacts of bonus depreciation and Moody's adjustments for pensions.

Despite almost $1 billion contributed to pension plans in 2010 and 2011, CEI expects it would need to continue making large contributions to its underfunded pensions if discount rates stay low and the stock market remains weak. CEI's pension obligations account for almost a fifth of the company's adjusted debt of $13.5 billion; consequently, these obligations will continue to have a significant impact on the company's credit metrics. In our adjustments, we treat cash contributions in excess of service cost as a reduction of pension debt. Counter-intuitively, increasing pension obligations and sizable contributions to the plan have resulted in unusually strong cash flow metrics which are not necessarily indicative of sustainable future performance.

About $358 million of excess pension contributions were reclassified to CEI's cash flow from operations before working capital changes (CFO pre-WC) in the last twelve months ended September 30, 2011. At the same time, tax refunds relating to repair allowance deductions and bonus depreciation boosted CFO by $416 million in the last twelve months ended September 2011. Additionally, the company reported $580 million of regulatory and other deferrals that were unusually high during this period and which Moody's does not consider to be sustainable. Together these effects made up almost 40% of CFO pre-WC in the last twelve months ended September 2011.

These effects combined produced CFO pre-WC Interest Coverage of 6.0x and CFO pre WC/Debt of 27% in the last twelve months ended September 30, 2011. Excluding all of these effects from CFO, these ratios were 4.1x and 17%, respectively, more in line with what we believe to be more sustainable levels of CFO pre-WC Interest Coverage in the high 3x-low 4x range and CFO pre-WC/Debt in the mid to high teens.

CEI had funds flow from operations ($2.4 billion reported in the last twelve months ended September 30, 2011) sufficient to finance its capital expenditures of about $2 billion.

Liquidity Profile

CEI has good liquidity resources to meet its anticipated funding needs over the next 12 months.

CEI, CECONY and O&R are co-borrowers under a committed $2.25 billion bank credit facility that expires in October 2016. CECONY is entitled to access up to the full $2.25 billion while CEI and O&R have $1.0 billion and $200 million sub-limit access, respectively. The credit agreement does not require the companies to represent and warrant as to material adverse change, litigation or full disclosure that would restrict access to the facility. It has a financial covenant which limits consolidated Debt/Capitalization (as defined in the agreement) to 65%. As of September 30, 2011, this ratio for each of CEI, CECONY and O&R was comfortably below this level. The credit facility provides a backstop to CEI's $1 billion commercial paper (CP) program as well as the CP programs of CECONY and O&R which are FERC-authorized up to $2.25 billion and $200 million, respectively. The only scheduled debt maturity over the next 12 months is a $300 million issue due on July 1, 2012 at CECONY.

Rating Outlook

CEI's stable rating outlook reflects Moody's expectation that CEI's financial metrics over the near term will be temporarily higher than what we anticipate longer term (CFO pre-WC Interest Coverage in the high 3x-low 4x range and CFO pre-WC/Debt in the mid to high teens).

What Could Change the Rating - Up

While we do not consider it likely in the near-term, an upgrade in CEI's rating would require evidence of a less challenging regulatory environment combined with a strengthening of CEI's credit metrics; for instance, CFO pre-WC/debt and CFO pre-WC Interest Coverage in excess of 19% and low 4x range, respectively, on a sustainable basis.

What Could Change the Rating - Down

CEI's rating could be downgraded if there is a deterioration in the utilities' regulatory environment or a sustained weakening in the credit profiles of its utilities subsidiaries, particularly CECONY. If CEI's CFO pre-WC Interest Coverage and CFO pre-WC/Debt fall below 3.3x and 13%, respectively, for an extended period, then CEI's rating would likely be downgraded. CEI could also be downgraded if its unregulated competitive subsidiaries become a more significant portion of its overall operations and/or if there was a significant increase in the amount of debt at the holding company or the competitive subsidiaries.

Rating Factors

Consolidated Edison, Inc.

Regulated Electric and Gas Utilities Industry [1]	[2] **Current**		[3]**Moody's 12-18 month Forward View As of 12/20/2011**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		Baa		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (10%)		A		A
b) Generation and Fuel Diversity (0%)				
Factor 4: Fin. Strength, Liquidity And Key Fin. Metrics (40%)				
a) Liquidity (10%)		A		A
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	4.5x	Baa	4.5x-5x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	19.2%	Baa	19%-22%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	14.6%	Baa	14%-17%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	45.2%	Baa	42%-45%	A
Rating:				
a) Indicated Baseline Credit Assessment from Methodology Grid		Baa1		Baa1
b) Actual Baseline Credit Assessment Assigned		Baa1		Baa1

Source: Moody's Financial Metrics.

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments. In addition, Moody's adjusts for one-time items. [2] Financial ratios reflect three year averages for 2008, 2009 and 2010. [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

Global Credit Research
Credit Opinion
18 MAY 2012

Credit Opinion: Integrys Energy Group, Inc.

Integrys Energy Group, Inc.

Chicago, Illinois, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Senior Unsecured	Baa1
Jr Subordinate	Baa2
Commercial Paper	P-2
Wisconsin Public Service Corporation	
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	Aa3
Senior Secured	Aa3
Pref. Stock	Baa1
Commercial Paper	P-1
Peoples Gas Light and Coke Company	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured MTN	(P)A1
Commercial Paper	P-2
North Shore Gas Company	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured MTN	(P)A1

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Key Indicators

[1]
Integrys Energy Group, Inc.

	2011	**2010**	**2009**	**2008**
(CFO Pre-W/C + Interest) / Interest Expense	**6.7x**	**6.0x**	**5.5x**	**5.3x**
(CFO Pre-W/C) / Debt	**28%**	**27%**	**27%**	**18%**
(CFO Pre-W/C - Dividends) / Debt	**21%**	**21%**	**20%**	**13%**
Debt / Book Capitalization	**41%**	**44%**	**45%**	**52%**

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Utility subsidiaries operate in diverse and relatively supportive regulatory environments

Repositioning of non-regulated businesses

Strong financial performance

Large capital spending program

Significant holding company debt and above average dividend payout

Corporate Profile

Integrys Energy Group, Inc. (Integrys: Baa1 senior unsecured, stable outlook) is a diversified energy holding company headquartered in Chicago, Illinois that was created through the February 2007 merger between WPS Resources and Peoples Energy, LLC (PEC).

Integrys owns six regulated utilities, Wisconsin Public Service Corporation (WPSC: A2 Issuer Rating), The Peoples Gas, Light and Coke Company (PGL: A3 Issuer Rating), North Shore Gas Company (NSG: A3 Issuer Rating), Minnesota Energy Resources Corporation (MERC: not rated), Michigan Gas Utilities Corporation (MGUC: not rated) and Upper Peninsula Power Corporation (UPPCO: not rated) that in the aggregate serve approximately 1.7 million gas and 500,000 electric customers in Wisconsin, Illinois, Michigan, and Minnesota. The most sizable utilities are WPSC, a vertically-integrated electric utility headquarter in Green Bay, Wisconsin and PGL, a local natural gas distribution company(LDC) that operates in and around Chicago.

Integrys also has an approximate 34% ownership interest in the American Transmission Company (ATC: A1 senior unsecured).

Integrys' non-regulated retail energy marketing business is focused on marketing natural gas and electricity to commercial, industrial and residential customers primarily in the northeastern quadrant of the United States. Moody's estimates Integrys' non-regulated energy marketing business currently accounts for 10- 15% of the company's annual cash flow .

Rating Rationale

Moody's evaluates Integrys' consolidated financial performance relative to the Regulated Electric and Gas Utilities rating methodology (the methodology) published in August 2009. As depicted in the grid below, Integrys' indicated rating under this methodology is Baa1 compared to its current Baa1 senior unsecured rating. The indicated rating under the methodology considers Integrys' consolidated financial performance based on a three-year historical average.

Integrys is well positioned in the Baa1 rating category. The company's rating is supported by the underlying cash flow stability provided by its six regulated utility subsidiaries, a diverse, multi-state service territory and strong historical financial performance. The rating, however, is tempered by the degree of holding company debt, the risk profile of its non-regulated business and an above average dividend payout.

DETAILED RATING CONSIDERATIONS

The primary drivers for the rating and outlook are as follows:

Diverse and reasonably supportive regulatory environments

Integrys has successfully reduced the business risk profile of the enterprise through the acquisition of four regulated gas utilities, MGUC in April 2006, MERC in June 2006 and NSG and PGL in February 2007 followed by a restructuring of its non-regulated business in 2009-2010. As a result, Integrys' regulated utilities (including its investment in ATC) which operates in four states, typically account for approximately 85-90% of its annual consolidated cash flow.

Generally speaking, Integrys' regulated LDC utilities operate in relatively supportive regulatory environments that provide PGL, NSG, MGU and MERC with rate mechanisms to pass gas costs directly to their customers and to recover bad debts. Furthermore, PGL, NSG and MGU have been granted decoupling mechanisms to offset the financial impact of declining usage. MERC requested a decoupling mechanism in its recent rate case filing and we expect the request to be approved in a final order expected in the second quarter. An offset to these allowed recovery mechanisms by regulators, a credit positive, is the below average allowed return on equity (9.45%) granted to PGL and NSG.

The supportive regulatory environments in which the LDC's operate combined with the strong regulatory environment provided in Wisconsin supports a high-Baa rating factor for Factor 1: Regulatory Framework within Moody's methodology. That being said, we have notched this rating factor downward to reflect the higher risk profile of Integrys' remaining non-regulated business; however, a high-Baa rating factor has been assigned for Factor 2: Ability to Recover Costs and Earn Returns.

Reduced scale and scope of non-regulated energy marketing business

Integrys substantially reduced the scale and scope of its non-regulated energy marketing businesses in 2009-2010 largely by selling several businesses with substantial collateral requirements.

Integrys' remaining non-regulated business is focused on marketing electricity and natural gas in the retail market serving commercial, industrial, direct and aggregated small commercial and residential customers primarily in the northeastern quadrant of the United States. Integrys manages the supply risk of its natural gas marketing business through a multi-year natural gas supply agreement with a creditworthy counterparty. Specifically, this agreement provides Integrys with sufficient capacity to meet the natural gas requirements of its energy marketing business and includes a contractually set limitation on collateral support requirements.

Integrys has always provided collateral support on behalf of its non-regulated energy marketing businesses. As this business grew in scale, so did the collateral requirements, thereby pressuring Integrys' liquidity profile. The downsizing of this business segment, however, has resulted in significantly reduced collateral requirements. Guarantees and other forms of corporate support provided by Integrys on behalf of its non-regulated operations to support its commodity transactions declined to less than $600 million as of March 31, 2012 from $2.5 billion at December 31, 2008. Cash collateral provided to third parties declined to $64 million from $256 million during the same timeframe. Furthermore, the collateral requirement associated with a hypothetical downgrade of Integrys' rating to below investment grade has declined to a more manageable $271 million at March 31, 2012 from approximately $700 million at December 31, 2008.

Strong key financial metrics

Integrys achieved CFO-pre WC to debt of approximately 28% and cash flow coverage of interest expense of 6.7 times for 2011 compared to 27% and 6.0 times, respectively, in 2010. Integrys' strong financial metrics in these years were driven in part by the impact of bonus depreciation. Specifically, Integrys received a federal tax refund of $80 million in 2011 and $2 million in 2010. Without bonus depreciation, Moody's estimates that Integrys' key financial metrics would have ranged between 22-26% and 5-6 times, respectively, during this two-year timeframe.

The company anticipates a significant reduction in taxes again in 2012 due to bonus depreciation. Our rating and outlook assumes a normalization of depreciation and an expectation that Integrys maintains consolidated CFO-pre WC to debt in the 20-25% range and interest coverage in excess of 5.0 times over the next several years.

Integrys consolidated capital expenditure program for the three-year period 2012 through 2014 is significant at an estimated $2.3 billion (compared to $1.0 billion for the three year period ended 2011). The primary drivers for the increase in capital spending are PGL's accelerated cast iron replacement program and environmental controls on WPS's coal plant facilities. Both utilities are expected to file frequent rate cases to ensure timely recovery of these investments.

Integrys' subsidiaries are expected to fund their respective capital expenditure programs with internally generated funds, incremental debt and parent equity contributions. Integrys anticipates an incremental holding company debt offering in the 2012-2014 timeframe and may issue equity to fund in part its capital expenditure program.

Significant holding company debt and above average dividend payout

Integrys' rating reflects in part the significant amount of holding company debt and the current high dividend payout ratio, which are the primary drivers for the two-notch rating difference between it and the senior unsecured rating assigned to WPSC, its largest regulated subsidiary. At 12/31/2011 long-term holding company debt was $708 million (adjusted for a $270M hybrid security that currently receives 25% equity and 75% debt treatment for financial leverage purposes by Moody's) or approximately 30% of consolidated long-term balance sheet debt.

Integrys' dividend payout to its shareholders in 2011 was approximately $206 million or 90% of consolidated net income. That said, the company's earnings are somewhat influenced by mark-to-market accounting at its energy marketing business. For example, in 2011, the company earnings were skewed by $48 million (after-tax) of net unrealized losses on non-regulated energy contracts. Ignoring this non-cash impact, Integrys' dividend payout in 2011 was approximately 74%, which is slightly higher than industry average of 65-70%.

Liquidity Profile

Integrys proactively manages its liquidity profile to ensure access to funds in an amount comfortably in excess of all potential requirements.

Integrys' parent's external sources of liquidity include $1,210 million of unsecured revolving credit facilities commitments ($735 million due April 2013, $275 million due in May 2014 and $200 million due in May 2016) to support the issuance of letters of credit, to meet short-term funding requirements and to provide alternate liquidity for its commercial paper program. Terms of the syndicated revolving credit facilities include a representation that no material adverse change has occurred on the facilities' effective date (but not at any other times throughout the facility's term). The sole financial covenant is a 65% limitation on the debt component of Integrys' capital structure. The company has substantial headroom under the capital structure covenant ; we estimate that Integrys' debt-to-capitalization for the purpose of this covenant is currently at approximately 45%.

Integrys had approximately $92 million of commercial paper outstanding and $34 million of letters of credit issued under its credit facilities at December 31, 2011. The average amount of parent commercial paper outstanding during fiscal year 2011 was $75 million. The company's most near-term debt maturity is $100 million in December 2012.

Availability under Integrys' credit facilities are more than adequate to meet the potential $271 million collateral requirement associated with a hypothetical downgrade of Integrys' rating to below investment grade. We anticipate Integrys will extend the maturity of its $735 million facility due April 2013 during the second quarter.

Separately, WPSC and PGL have access to three credit facilities totaling $500 million in commitments to support their respective business requirements.

Rating Outlook

The stable rating outlook reflects a reduced business risk profile associated with the completed restructuring of the company's non-regulated businesses and an expectation that Integrys' consolidated ratio of CFO pre-W/C to debt will continue to exceed 20% for the near-to- medium term.

What Could Change the Rating - Up

Upward rating movement is not expected in the medium-term. Longer term, we would likely need to see Integrys' consolidated ratio of CFO pre-W/C to debt exceed 25% without the benefit of any temporary items such as bonus depreciation on a sustainable basis to consider an upgrade.

What Could Change the Rating - Down

Changes in regulatory supportiveness or an unexpected increase in leverage or decline in cash flow such that its ratio of CFO pre-W/C to debt falls below 17% on a sustainable basis.

Rating Factors

Integrys Energy Group, Inc.

Regulated Electric and Gas Utilities Industry [1][2]	**Current 12/31/2011**		**Moody's 12-18 month Forward View* As of May 2012**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		Baa		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (10%)		A		A
b) Generation and Fuel Diversity (0%)		Baa		Baa
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	6.0x	A	5.0x-6.0x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	27.6%	A	20-25%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	20.7%	A	15-17%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	43.3%	A	40-45%	A
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2011; Source: Moody's Financial Metrics

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Global Credit Research
Credit Opinion
21 DEC 2011

Credit Opinion: Northwest Natural Gas Company

Northwest Natural Gas Company

Portland, Oregon, United States

Ratings

Category	Moody's Rating
Outlook	Stable
First Mortgage Bonds	A1
Senior Secured	A1
Senior Unsecured MTN	A3
Jr Subordinate Shelf	(P)Baa1
Pref. Shelf	(P)Baa2
Commercial Paper	P-1

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Key Indicators

[1]
Northwest Natural Gas Company

	LTM 3Q11	2010	2009	2008
(CFO Pre-W/C + Interest) / Interest Expense	**5.2x**	**4.6x**	**4.7x**	**4.1x**
(CFO Pre-W/C) / Debt	**21%**	**18%**	**20%**	**14%**
(CFO Pre-W/C - Dividends) / Debt	**16%**	**13%**	**16%**	**10%**
Debt / Book Capitalization	**47%**	**49%**	**48%**	**51%**

[1] All ratios calculated in accordance with the Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Generally low business risk profile given dominance of gas distribution operations

Supportive regulatory environment offsets weak cash flow to debt metrics for the A3 level

Additions of business segments maintain 90% regulated business mix

Conservative financing anticipated for planned capital expenditure program

Corporate Profile

Northwest Natural Gas Company (NWN) is a natural gas local distribution company (LDC), serving approximately 675,000 customers in Oregon (about 90% of utility margins) and Washington (about 10% of utility margins). NWN is regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC). Natural gas is supplied via pipelines sourced from Alberta and British Columbia, Canada, as well as from the Rocky Mountain region of the United States. NWN also operates underground gas storage facilities, contracts for additional gas storage outside its service area, and operates two LNG plants in its service territory.

Recent Developments

In February of 2011, NWN entered into an agreement with Encana Oil & Gas (USA) Inc. (Encana; an unrated subsidiary of Encana Corporation, Baa2 senior unsecured, stable outlook) to develop physical gas reserves that are expected to supply a portion of NW Natural's utility customers' requirements over the next 30 years. The volume of gas produced and allocated to NW Natural under the agreement will increase in the early years as the company continues to invest in drilling, with volumes expected to peak at about 13 percent of NWN's utility gas supply requirement in gas year 2015-2016. Over the first 10 years of the agreement (2011-2020), volumes are expected to average approximately 8 to 10 percent of the annual gas purchase requirements of NWN's utility customers. Under the agreement, NWN expects to invest approximately $45 million to $55 million per year for five years, with the total investment reaching about $250 million.

In April of 2011, the OPUC approved the agreement between NWN and Encana, which will allow NWN to recover expenses related to the transaction through the company's Purchased Gas Adjustment mechanism (PGA) in Oregon, including the deferral mechanism for gas costs. It will also file a general rate case in Oregon by December 31, 2011.

SUMMARY RATING RATIONALE

NWN's A3 senior unsecured rating reflects the inherent low business risk of its LDC operations in jurisdictions that provide supportive regulatory treatment which compensate for the historical weak cash flow to debt financial metrics. The rating also considers the highly contracted nature of most of the non-LDC operations and relatively high reliance on residential and commercial customers - characteristics that can help mitigate risks associated with economic downturns. The development of the gas reserve business with Encana is also expected to support cash flow stability, thus contributing to the rating and outlook for NWN, as well.

DETAILED RATING CONSIDERATIONS

STRONG REGULATORY SUPPORT EXPECTED TO CONTINUE

The OPUC has historically proven to be a significant supporter to the credit profile of NWN. The leadership role that the OPUC has taken with rate mechanisms, including a weather normalization adjustment (WNA), a conservation tariff, and the purchased gas adjustment (PGA), have all helped set Oregon apart from most other regulatory commissions.

NWN's general rate case (GRC) moratorium (enacted in 2007, in connection with the renewal of NWN's conservation tariff and WNA) in Oregon ended as of September 1, 2011 and the company is anticipating filing a GRC by year-end with new rates effective by November 2012. The GRC will look to address the WNA and conservation tariff, which were scheduled to end October 2012, among other general rate matters. The rate base recovery for contracted gas reserves, associated with NWN's new agreement with Encana, are being addressed within the PGA mechanism (explained below).

As this is NWN's first general rate case in Oregon in nine years, there is some risk as to what will be allowed by the OPUC and the impact to the company's fixed cost recovery mechanisms, cost of capital, ROE, and capital structure, among any other items that NWN may want to pursue. Given the historical support and precedent for many of the items that will be topics in the GRC (i.e. WNA, conservation tariff and forward capex test year), Moody's expects that the outcome of OPUC approval will be credit neutral to credit positive for NWN.

SOPHISTICATED SUITE OF COST RECOVERY MECHANISMS PROVIDES CREDIT BENEFIT

NWN's WNA and conservation tariff, in Oregon, cover the majority of residential and commercial customers, and have been instrumental in reducing the impact of volume risk on margins. The WNA applies to bills in Oregon from December 1st to May 15th; however, there is no WNA mechanism or conservation tariff in Washington. An adverse change or elimination of the WNA and conservation tariff in NWN's upcoming GRC would be a credit negative.

NWN's Oregon PGA defers the difference between natural gas costs incurred as compared to the estimated amount included in rates and either collects or refunds the balance through an adjustment in future rates. Prices are fixed for approximately 75% of NWN's estimated gas purchase requirements each year. Under the current Oregon PGA incentive sharing mechanism, NWN is required to choose, each October, to defer either 80% or 90% of the cost difference for the gas prices that are not fixed, with an earnings threshold of either 150 or 100 basis points, respectively, above the allowed ROE. This incentive sharing mechanism helps balance interests of all parties by reducing some earnings risk for NWN, while continuing to encourage management to minimize natural gas costs for customers. In Washington, the PGA mechanism requires 100% pass through of prudently incurred gas cost deferrals, making it earnings neutral.

Under the PGA in Oregon, NWN has historically achieved net margin benefits from its incentive sharing mechanism. For the 2010-2011 and 2011-2012 PGA years, NWN selected the 90% deferral option, and based on the September 2011 report received from the OPUC following its review of NWN's 2010 performance under the PGA earnings sharing mechanism, the company's utility ROE of 11.1% was above the sharing threshold of 11.02%. As a result, NWN will be refunding $0.2 million to customers. For 2011, the company accrued a similar amount for potential refund to customers based on results through September 30, 2011.

The OPUC determined that the ongoing costs of NWN's portion of the Encana deal will be recovered through the annual PGA process with the current regulatory deferral and incentive sharing process for the cost of gas. Each year, NWN will submit a forecast for the costs and volumes expected, with any variance up to $10 million being subject to the incentive sharing in Oregon. Variances in excess of $10 million will be deferred and fully passed through to customers in future rates.

These various cost recovery mechanisms help to support the adequate and timely recovery of the most significant costs that face NWN. The credit support derived from the transparent and regulatory assured recovery of these costs is among the best in the industry, and provides a counterbalance to financial metrics that are somewhat weak for the current rating.

CURRENT CREDIT METRICS ARE WEAK FOR RATING, ESPECIALLY WHEN ADJUSTING FOR BONUS DEPRECIATION

NWN's credit metrics have been negatively impacted by several developments over the past few years, including Oregon's struggling economy, low natural gas prices affecting the company's storage segment and higher operating costs associated with the Gill Ranch storage facility, which became operational in 4Q10. In addition to these pervasive circumstances, NWN also experienced a one-time charge related to repealed utility tax legislation, which had some effect on 2010 results, as well as a second quarter charge, in 2011, of $7.4 million (pre-tax). These negative impacts have been partially masked by the tax savings associated with the use of bonus depreciation, which has helped NWN to post metrics approaching 5.0x CFO pre-WC interest coverage and 20% CFO pre-WC to debt, on average, for the year ended 2010 and LTM 3Q11. If the effects of bonus depreciation were removed from these 2010 and LTM metrics, NWN's metrics would be below the A3 rating category ranges, which our Regulated Electric and Gas Utilities Rating Methodology implies to be from around 4.5x - 5.0x CFO pre-WC interest coverage and 22% - 25% CFO pre-WC to debt.

Although Moody's does not see the use of accelerated bonus depreciation as an ongoing source of cash flow for the company (and thus remove its effects when considering NWN's core financial profile), we do not view the one-time tax legislation charge to be representative of a sustainable financial position of NWN, either. Furthermore, we view the recovery provisions of Oregon's WNA and conservation tariff to offset the effects of a continuing sluggish economy and declines in customer demand, as the company can recover margin associated with lost sales over the course of the subsequent twelve months. Additionally, though low natural gas prices have had a negative effect on the gas storage segment (primarily via Gill Ranch, which has less long-term sales contracts than the MIST storage facility), the tempered commodity environment has helped NWN to lower the cost of LDC customer bills, which lowers the risk of regulatory or political intervention in the rate making process which is especially useful during economic downturns.

NWN's financial profile is underpinned by low-risk, predictable and stable cash flow generation of LDC assets and services. NWN is the largest LDC in the Pacific Northwest, with no direct competition in its service territory from other natural gas distributors. Such market competitiveness and dominance of regulated operations are a credit-positive, as they support the stability and predictability of the company's earnings and cash flows, with residential customers providing over 80% of NWN's revenue and margins.

As approximately 90% of its earnings derived from regulated operations (which should be maintained as both unregulated storage and regulated gas reserves grow their earnings contribution levels over the long-term), Moody's views the long-term financial profile of NWN to be rather stable and capable of producing key credit metrics approaching 5.0x and above 20% CFO pre-WC to interest and CFO pre-WC to debt, respectively, even absent the beneficial cash contribution of bonus depreciation.

NEW SEGMENT DEVELOPMENTS MAINTAIN REGULATED DOMINANCE

Given the dominance of NWN's low-risk LDC operations and the highly contracted nature of its other business segments, including the unregulated MIST storage facility, NWN's business mix is viewed to be relatively stable from a credit perspective. Even with the addition of the unregulated operations from the Gill Ranch storage facility near Fesno, California, NWN's joint venture with Encana, which received OPUC approval for rate base treatment and regulated cost recovery, should provide a positive offset to Gill Ranch's struggling operations. NWN hopes that over time, market fundamentals and/or regional needs for Gill Ranch will improve, making the strategically placed storage facility more profitable.

NWN has estimated that around $400 million will be spent in utility capital expenditures from 2012-2015, with other investments targeted toward gas storage and pipeline projects dependent upon regulatory and Federal approval for the need of such projects. With Gill Ranch entering full operations in 4Q10, we see that most of the committed capex for non-utility purposes has been spent, which should provide for a less risky base-capex plan over the near-term. Moody's would expect that any capex invested in non-utility assets will undergo significant scrutiny from NWN management and will have various regulatory safeguards in place before any actual spending occurs.

For example, NWN has opportunities to invest in storage expansion in its MIST facility, which could provide back-up requirement for electricity provided by wind generation assets, as well as the Palomar East pipeline, which is envisioned to provide a second delivery path for gas supplies to enter the Pacific Northwest region; providing for reliability, safety and regional growth.

In regard to the Palomar project, in May 2010, a company proposing to build an LNG terminal as a part of the Palomar project filed for Chapter 7 bankruptcy, requiring NWN to proceed with the project with greater caution and monitoring. As of September 30, 2011, NWN had a $14.4 million share of around a $29 million total equity investment in the Palomar project which also includes TransCanada (A3 senior unsecured, stable outlook) and $15.8 million collected under a letter of credit that supported the bankrupt shipper's obligations under a prior shareholder's agreement the companies previously entered into for a majority of the transmission capacity on the proposed pipeline. NWN management continues to believe the eastern portion of the project is viable, and is expecting to file a revised FERC application by early 2012 to address changes in the scope of the project. NWN will continue to monitor the progress and should the company learn that the project will not go forward, would recognize a maximum impairment charge of up to $14.1 million, based on the current equity investment, cash and working capital at Palomar.

Liquidity

NWN maintains a sufficient liquidity profile with external liquidity sources supplementing its operating cash flows to help meet short-term working capital needs. The company had almost $26 million in cash at September 30, 2011 and maintains a $250 million credit facility that expires in May of 2013. The facility is primarily used to backstop NWN's commercial paper, but the full amount is also available for issuance of letters of credit. As of September 30, 2011, NWN had $181 million of short-term debt outstanding that was primarily used to fund gas inventory for the upcoming winter heating season. The credit facility has one financial covenant that limits NWN's debt to capitalization ratio to 70%, as defined. NWN had ample cushion under this covenant at September 30, 2011, at 54%.

Moody's anticipates that 2012 cash flow from operations should approximate $200 million, which will cover most of its capital expenditures; however, dividends approaching $50 million will constitue the bulk of the company's negative free cash flow. Moody's expects this negative free cash flow will be funded with a mix of debt and equity to keep balance sheet ratios close to current levels.

NWN faces only modest long-term debt maturities over the near term, with $40 million of FMBs due in March 2012.

Rating Outlook

NWN's stable rating outlook reflects Moody's expectation that supportive regulation will continue through the upcoming general rate case proceeding in Oregon, that financing of future investments will remain conservative and that key financial metrics will improve over the intermediate-term.

What Could Change the Rating - Up

An upgrade appears unlikely in the medium term as we anticipate key metrics to stay comparable to the current level; however, an upgrade might be considered if the company can demonstrate an ability to sustain CFO Pre-WC coverage of interest and debt metrics around 5.0x and 25%, respectively, over a multi-year period.

What Could Change the Rating - Down

The rating could be revised downward if NWN experiences less constructive regulatory treatment (especially in regard to the Oregon general rate case), or sustained credit metrics of CFO pre-WC interest coverage and CFO pre-WC to debt around 4.0x and high teens, respectively. A negative rating action could also stem from a shift toward aggressive financing of capital expenditure and/or aggressive expansion of non-regulated businesses.

Rating Factors

Northwest Natural Gas Company

Regulated Electric and Gas Utilities Industry [1][2]	**Current LTM 12/31//2010**		**Moody's 12-18 month Forward View* As of December 21, 2011**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		Baa		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (10%)		A		A
b) Generation and Fuel Diversity (0%)		NA		NA
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Ba		Ba
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	4.5x	Baa	4.0x - 5.0x	Baa/A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	17%	Baa	15% - 20%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	13%	Baa	10% - 15%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	49%	Baa	45% - 50%	Baa
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		A3		A3

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2010; Source: Moody's Financial Metrics

Moody's Investors Service

Global Credit Research
Credit Opinion
2 MAR 2012

Credit Opinion: Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas Company, Inc.

Charlotte, North Carolina, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Senior Unsecured	A3
Commercial Paper	P-2

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Key Indicators

[1]
Piedmont Natural Gas Company, Inc.

	2011	**2010**	**2009**	**2008**
(CFO Pre-W/C + Interest) / Interest	**6.4x**	**5.7x**	**6.5x**	**4.6x**
(CFO Pre-W/C) / Debt	**28%**	**26%**	**24%**	**19%**
(CFO Pre-W/C - Dvidends) / Debt	**20%**	**18%**	**17%**	**13%**
Debt / Book Capitalization	**41%**	**42%**	**47%**	**52%**

[1] All ratios calculated in accordance with the Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

- Primarily a rate regulated business in credit supportive regulatory environments

- Continued prudent financial policies in support of Piedmont's material capex program over the medium-term

- Credit metrics expected to register at the lower range of its current rating category

- High dividend payout ratio

Company Profile

Headquartered in Charlotte, NC, Piedmont Natural Gas Company (Piedmont) is a local gas distribution company (LDC) with approximately one million customers, including over 50,000 customers served by municipalities that are Piedmont's wholesale customers. Its main service territory is in North Carolina (around 70% of the operating margins) but it also serves certain areas in southwest South Carolina (15%) and the metro area of Nashville, Tennessee (15%).

Piedmont also holds indirect equity stakes in several energy related joint ventures (JV), including Hardy Storage Company (50%; West Virginia), the intrastate Cardinal pipeline (21.49%) serving North Carolina, Pine Needle LNG Company LLC (40%; Pine Needle

LNG), as well as the unregulated retail natural gas marketing JV, South Star Energy Services (15%; SouthStar).

The NC Utilities Commission (NCUC) regulates Piedmont's activities in NC as well as Cardinal Pipeline's operations. Piedmont is also subject to the purview of the Public Service Commission of SC (PSCSC) and the Tennessee Regulatory Authority (TRA). The Federal Energy Regulatory Commission (FERC) regulates the interstate transportation and storage of natural gas activities, conducted at Pine Needle and Hardy Storage.

At October 31, 2011, Piedmont reported funds from operations (FFO) of $297 million and total assets of about $3.2 billion with regulated LDC activities accounting for 97%.

Rating Rationale

Piedmont's A3 senior unsecured rating reflects Piedmont's adequate liquidity profile and cash flow predictability resulting from the limited volumetric exposure of the company's margin. It further captures Piedmont's low LDC business risk and the credit supportive regulatory framework of its multi-jurisdictional operations under which it operates, as well as its limited exposure to unregulated activities. The rating also captures our expectation of continued prudent financial policies to fund Piedmont's material capital expenditure (capex) program with investments in the 2012-2014 period aggregating to over $1 billion. Moody's rating reflects Piedmont's public commitment to maintain its target capitalization ratio considering only long-term debt of 45% to 50%, and assumes that Piedmont's balance sheet will remain strong with key credit metrics continuing to score at the low end of the A-rating category despite management's intention to maintain its target dividend payout ratio at a relatively high 70%.

DETAILED RATING CONSIDERATIONS

LIMITED UNREGULATED ACTIVITIES

Piedmont's limited exposure to unregulated activities arises exclusively through its 15% ownership in the natural gas retail marketer, South Star, that operates mainly in Georgia but also in NC and SC, TN, Florida and Ohio. This operation contributed less than 10% of Piedmont's earnings before taxes (2011: 8%), a credit positive. The associated primary risk consists of funding up to 15% of any additional liquidity needs that SouthStar may have beyond its existing $75 million short-term credit line facility, which we considered limited given the size of its operations.

CREDIT SUPPORTIVE REGULATORY ENVIRONMENTS

Moody's ranks the regulatory environments in NC (around 72% of Piedmont's net asset base), SC (10%) and Tennessee (18%) in the top tier of all state jurisdictions only after the FERC's regulatory framework in terms of credit supportiveness based on timely cost and investment recovery. The rating also factors Piedmont's constructive relationship with those regulatory bodies.

Our opinion is underpinned by the TRA's approval of PNG's December 2011 comprehensive rate case settlement that was filed in Tennessee in September 2011. This was the first jurisdictional rate case since 2003, and was driven by Piedmont's increased operating expenses and capex (+$272 million) associated with the addition of over 13,000 new customers, the upgrade and replacement of aging distribution and transmission assets amid declining customer usage since 2003. The settlement allowed for a $11.9 million rate increase (+6.3%), effective March 1, 2012, based on a 10.2% RoE and common equity of 52.7%. It also allowed for the amortization over an eight-year period of certain deferred regulatory assets and rate case expenses (including $2.7 million deferred defined benefit pension costs). The rate increase representedaround 71.3% of PNG's requested hike, a credit positive, with the gap largely resulting from a computational difference in the W/C, accumulated depreciation and deferred income taxes. On a less positive note, Piedmont's requested modification of the design of its residential and commercial customers to increase the fixed component of the rate was not fully accepted, albeit we acknowledge an overall increase compared to the previous applicable rates. This is relevant since the fixed components aid in insulating the company's cash flows from volumetric fluctuations.

A credit positive in Tennessee compared to the other two jurisdictions is that rate cases are set on a forward looking basis with the 2011 settlement's attrition period ending in February 2013, while in NC and SC the rate cases are set on a historical test-period in NC (last rate increase effective in November 2008) and SC (November 2009). We consider the first more credit supportive because it somewhat reduces regulatory lags by enhancing the company's ability to recover investments on more timely basis, such as Piedmont's planned $33 million capex in Tennessee for pipeline integrity and safety improvements to be invested during the attrition period ending February 2013.

That said, we consider Piedmont's full margin decoupling mechanism for residential and commercial customers in NC a significant credit positive. This is subject to semi-annual rate adjustments to refund or collect any over/under collection of margin regardless of those customers' demand. In SC, Piedmont also benefits from rate stabilization tariffs for those customer segments that allow for annual true-ups of revenues and expenses back to the company's allowed RoE within a +/- 50bp-band. On November 1, 2011, an approved settlement became effective allowing for a $3.1 million annual margin decrease based on a 11.3% RoE but lower depreciation of Piedmont's utility plant in service in SC (2011: $1.9 million; 2010: +$1 million). The impact of volume fluctuations during the winter season is also partially offset via Weather Normalization Adjustments (WNA) in SC and Tennessee.

Also a credit positive is the ability of the TRA and the NCUC to grant interim rate relief, while this is only allowed under certain circumstances in SC. In all three jurisdictions, Piedmont's rates also include recovery of uncollectible expenses as well as Purchased Gas Adjustment clauses for the natural gas cost portion; however, the latter are subject to annual prudency reviews in NC and SC albeit they have never been contested. In NC, Piedmont's hedging program is also subject to annual cost review proceedings, which are pre-approved by the TRA (up to 1% of total annual gas costs) and in SC for a 12 month horizon. Piedmont's gas cost hedging plans in NC and SC target between 22.5% and 45% of the annual normalized sales volumes in those states. Given the current low natural gas price environment and lower than historical volatility, material spikes in prices are less of a concern; however, Moody's considers Piedmont's hedging programs and ability to recover the associated costs a credit positive.

In all three states, Piedmont is entitled to recover cuts in margins resulting from negotiations with industrial customers to prevent them from switching to an alternate fuel. Piedmont is subject to sharing mechanisms between customers and shareholders under its secondary marketing programs. It is allowed to keep 25% of the margin generated by these activities, but profits are capped at $1.6 million in Tennessee.

DIVERSIFICATION AND LIMITED VOLUMETRIC EXPOSURE UNDERPIN ITS CASH FLOW PREDICTABILITY

The rating incorporates the diversification benefits associated with the multi-jurisdictional nature of Piedmont's regulated operations coupled with the JV-distributions (around $20 million p.a.) that also provide access to different natural gas sources.

Another credit positive is the company's cash flow predictability resulting from the limited volumetric exposure of the company's margin. At FYE 2011, the fixed component represented about 70% of the reported margin with the NC margin decoupling mechanism contributing around 41%, followed by facilities charges (23%) and fixed-rate contracts (6%). The semi-fixed rate design components associated with the rate stabilization tariffs in SC and the WNC in SC and TN account for 18%. Moody's understands that following the increase in the monthly charges in Tennessee under the settlement agreement the fixed-margin component may increase by another 1% to 2%.

The rating also factors the company's substantial exposure to residential and commercial customers (year-end 2011: 82% of Piedmont's margins) amid a rather limited contribution by the industrial (8%), power (4%) and wholesale market (2%) segments. Albeit at a slower pace than historical levels, Piedmont's customer base is still growing due to conversions from electricity and propane to natural gas, power generation gas delivery services as well as residential new construction. Piedmont forecasts its gross customer addition at 1% during 2012 the same as in 2011.

MATERIAL CAPEX PROGRAM

Piedmont has publicly disclosed that it plans to invest up to $1.2 billion between 2012-2014 (2011: $243.6 million) to grow its utility infrastructure. The bulk of the capital outlays is associated with its two large projects to provide long term delivery service to Progress Energy Carolinas (sr unsec: A3; stable) natural gas fired facilities. These include the 950MW Wayne County (Piedmont's capex up to $125 million; scheduled completion in June 2012) and the 630MW Sutton (Piedmont's capex up to $335 million; scheduled completion in June 2013) facilities. Further investments are related to the LDC's pipeline integrity program (between $70 and $80 million).

The rating is currently tempered by the risks associated with the successful completion of this sizeable capex program, particularly when compared with the company's net PP&E (FYE 2011: $2.6 billion). That said, we believe Piedmont should be able to smoothly complete the program given its successful track record completing work during 2011 at three other projects included in its power generation service portfolio, namely the Buck and Dan River combined-cycle plants owned by Duke Energy Carolinas (sr. unsec: A3; stable) as well as Progress Energy's Richmond County facility.

Piedmont will also contribute through September 2012, $10.3 million to the $48 million firm capacity expansion of the Cardinal pipeline. Piedmont has executed an agreement for additional capacity to meet its commitments at the Wayne County project (from 37% to around 53%) mentioned earlier.

CREDIT METRICS WITHIN THE RATING CATEGORY

Piedmont's 2009-2011 CFO pre-W/C to debt and interest coverage averaged 25.5% and 6.2x, respectively, which are strong for its current rating category. That said, we calculate that excluding the tax savings associated with the bonus depreciation Piedmont's 2009-2011 CFO pre-W/C to debt would average around 24% (FYE 2011: 24.5%) which is more commensurate with the low-end of the A-rating rating. Furthermore, given Piedmont's dividend target payout ratio of 65% to 75%, its 2009-2011 RCF to debt averaged 18.1%, an improvement compared to the 2008-2010 average of 15.6%. However, we calculate that excluding the tax savings associated with the bonus depreciation Piedmont's 2009-2011 RCF to debt would average 16.5%, which is more consistent with strong Baa-credit metric.

For 2012, we expect a positive impact on Piedmont operating cash flows associated with the implementation of the Tennessee settlement such that it will be able to reduce the gap registered in that jurisdiction between the actual (around 6% at FYE 2011) and allowed RoE. Cash flows should be further aided by the modest growth in margin associated with gross customer additions, management's focus on controlling operating costs despite the anticipated 9% increase in O&M expenses. This will be largely driven by higher medical costs, pension expense, and payroll but also by regulatory asset amortizations.

We expect that Piedmont will continue its prudent financial policies to fund its material capex over the medium-term given its public commitment to maintain its target capitalization ratio considering only long-term debt of 45% to 50% (FYE 2011: 40%). In July 2011, Piedmont filed a combined debt and equity shelf registration statement with the SEC, while its plan to issue $300 million of long-term debt during its fiscal 2012 third quarter. Despite these material investments, Piedmont has increased the range of its target dividend payout ratio to between 65% and 75%, a credit negative. Piedmont will also continue pursuing open market share repurchases during

2012 at a level that offsets its dividend reinvestment and other stock based programs without any material permanent reduction in its shares. The rating assumes that Piedmont's balance sheet will remain strong with key credit metrics continuing to score at the low end of A rating category, specifically, a CFO pre W/C to debt and CFO pre-W/C interest coverage to be at least 22% and 4.5x, respectively.

Liquidity

We assigned on March 1, 2012, a Prime-2 rating to Piedmont's commercial paper program. This will be backstopped by its $650 million 3-year committed revolving credit facility (with an accordion feature for an additional $200 million). This facility matures in 2014, and includes a line of credit for letters of credit of $10 million. Borrowings under this facility are not subject to any conditionality, including any MAC clause, but do require the maintenance of one financial covenant. Piedmont comfortably complies with the sole financial covenant under the credit facility of a maximum debt to total capitalization limitation of 70% (year-end 2011: 51%). As of October 31, 2011, Piedmont's outstanding borrowings under the facility amounted to $331 million, while LoCs were $3.5 million.

Piedmont has historically used short-term borrowings under its credit facility for working capital needs (including its hedging program) but also to fund portions of its capex program until long-term financing is arranged. We expect this practice to continue going forward with the new CP program, and that it will use the proceeds from its 2012 planned $300 million notes to repay outstanding short-term debt. Piedmont has no significant scheduled maturities over the next few years after $100 million becomes due in December 2013. We also expect that in addition to its internally generated cash flows (2011: $331 million) Piedmont will continue during 2012 to issue common stock through both its dividend reinvestment as well as its employee stock purchase plans (2011: $20.2 million), to fund its dividends (2011: $82.9 million) and share repurchases (2011: $23 million). Piedmont usually holds modest amounts of cash (FYE 2011: $6milion).

Piedmont's Prime-2 short-term rating assumes that the company will manage liquidity in an adequate fashion, including the maintenance of ample availability under the company's committed revolving facility to cover potential calls on capital, including issued commercial paper or alternatively, letters of credit under the facility.

Under the provisions of certain senior note agreements, Piedmont's ability to maintain its dividend payout ratio of 60% to 70% and invest in subsidiaries is limited to net earnings available for restricted payments exceeding the retained earnings. We do not expect this provision to impact Piedmont's ability to pay distributions over the near term.

Rating Outlook

The stable outlook reflects our expectation that Piedmont will continue to receive credit supportive regulatory treatment across each of its jurisdictions and that management will continue to implement prudent financial policies such that its capex program is funded in a way that allows its key credit metrics to remain reasonably well positioned within its current rating category.

What Could Change the Rating - Up

Given the material investments and the associated increase in leverage, limited prospects exist for the rating to be upgraded in the near term. However, a rating upgrade could be considered upon successful completion of the capex program, if credit metrics improve such that Piedmont reports CFO pre-W/C to debt and interest above 25% and 5.5x, respectively, on a sustainable basis.

What Could Change the Rating - Down

Ratings could be downgraded if there is a significant deterioration in the company's regulatory environments or in the company's business risk profile. The latter could be driven by a substantial increase in unregulated activities, greater use of leverage to fund its capital investment program, a dividend payout ratio that exceeds the company's current target, or a substantial increase in share repurchases leading to higher leverage or a deterioration in financial metrics. Specifically, a decline in the ratio of CFO pre-W/C to debt and interest below 20% and 3.5x, respectively, for an extended period, could trigger a rating downgrade.

Other Considerations

Moody's evaluates Piedmont's financial performance relative to the Regulated Electric and Gas Utilities rating methodology and as depicted in the grid below on both a historical and prospective basis, the company's indicated rating is A3, the same as its assigned senior unsecured rating.

Rating Factors

Piedmont Natural Gas Company, Inc.

Regulated Electric and Gas Utilities [1][2]	**Current 12/31/2011**			**Moody's 12-18 month Forward View As of March 2011***	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**		**Measure**	**Score**

a) Regulatory framework		A		A
Factor 2: Ability to Recover Cost and Earn Returns (25%)				
a) Ability to recover Cost and Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position		A		A
b) Generation and Fuel Diversity		n.a.		n.a.
Factor 4: Financial Strength, Liquidity, & Metrics (40%)				
a) Liquidity		Baa		Baa
b) CFO (pre w/c) + Interest / Interest (3 year Avg)	6.2x	Aa	4.5x-6.0x	A
c) CFO (pre w/c) / Debt (3 year Avg)	25.5%	A	22%-25%	A
d) CFO (pre w/c) - Dividends / Debt (3 year Avg)	18.1%	A	15%-17%	Baa
e) Debt / Capitalization (3 year Avg)	43.5%	A	45%-50%	Baa
Rating:				
Indicated Rating from Grid		A3		A3
Actual Rating Assigned		A3		A3

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2011; Source: Moody's Financial Metrics

Global Credit Research
Credit Opinion
24 FEB 2012

Credit Opinion: Southern Company (The)

Southern Company (The)

Atlanta, Georgia, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Jr Subordinate Shelf	(P)Baa2
Commercial Paper	P-2
Georgia Power Company	
Outlook	Stable
Issuer Rating	A3
Sr Unsec Bank Credit Facility	A3
Senior Unsecured	A3
Jr Subordinate Shelf	(P)Baa1
Pref. Stock	Baa2
Alabama Power Company	
Outlook	Stable
Issuer Rating	A2
Sr Unsec Bank Credit Facility	A2
Senior Unsecured	A2
Jr Subordinate Shelf	(P)Baa1
Pref. Stock	Baa1
Commercial Paper	P-1

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Key Indicators

[1]
Southern Company (The)

	LTM 9/30/2011	2010	2009	2008
(CFO Pre-W/C + Interest) / Interest Expense	6.2x	5.3x	4.4x	4.5x
(CFO Pre-W/C) / Debt	24%	21%	19%	18%
(CFO Pre-W/C - Dividends) / Debt	17%	14%	12%	11%
Debt / Book Capitalization	45%	47%	50%	50%

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

- Utility subsidiaries operate in generally credit supportive regulatory environments

- New Vogtle nuclear construction project has increased Georgia Power's business risk profile

- Substantial capital expenditure program over next three years

- Kemper IGCC plant increasing capital expenditures and business risk at Mississippi Power

- Potentially growing renewable energy business outside of the Southeast at Southern Power

Corporate Profile

Based in Atlanta, GA, The Southern Company (Southern) is a utility holding company that owns four vertically integrated regulated utilities: Georgia Power Company (A3 senior unsecured, stable outlook), Alabama Power Company (A2 senior unsecured, stable outlook), Mississippi Power Company (A2 senior unsecured, stable outlook) and Gulf Power Company (A3 senior unsecured, stable outlook) with an operating footprint across the Southeast. The company is also engaged in competitive electricity generation through Southern Power Company (Baa1 senior unsecured, stable outlook).

SUMMARY RATING RATIONALE

Southern's Baa1 senior unsecured rating reflects its position as the parent company of four regulated utility subsidiaries rated at low to mid-A rating levels and a highly contracted Baa1 rated wholesale generating company. Three of its four regulated utilities operate in consistently supportive regulatory environments, with the Florida regulatory environment stabilizing and potentially improving after a period of substantial uncertainty. Southern's traditionally low risk profile has increased modestly in recent years as a result of new nuclear and IGCC construction, substantial environmental compliance costs, and a thus far limited expansion into unregulated generation outside of its historical Southeast region, including biomass generation in Texas and solar generation in New Mexico. The company also has a renewable energy partnership with Ted Turner, the largest landowner in the U.S., to develop solar power.

DETAILED RATING CONSIDERATIONS

- Generally credit supportive regulatory environments, with base rate case pending in Florida

Southern's rating considers the consistently credit supportive regulatory environments in Alabama, Georgia, and Mississippi, which have generally strong cost recovery provisions. Its utility subsidiaries operate under various formula rate plans with authorized return on equity (ROE) levels that are above average for U.S. electric utilities. There are several adjustment mechanisms in place to address rising costs and each of the respective regulatory jurisdictions allows the utilities to adjust rates prospectively based on expected fuel and purchased power costs.

Moody's viewed Georgia Power's most recent rate case outcome as supportive of the utility's credit profile. The settlement included the implementation of a new, three year Alternate Rate Plan (ARP) that began on January 1, 2011. Under the plan, the company's retail return on equity is set at 11.15% and evaluated within a bandwidth of between 10.25% and 12.25%, with two thirds of earnings above the range refunded to customers and the remaining one-third retained by the company. Under the settlement, Georgia Power's base revenues increased by $562 million as of January 1, 2011, with subsequent rate adjustments of approximately $190 million in 2012 and $93 million in 2013. In total, rates will increase by approximately $845 million over the three years, compared to the company's initial request of slightly over $1.1 billion.

The political and regulatory environment for investor-owned utilities in Florida appears to have stabilized and may be improving following an almost complete change in the composition of the Florida Public Service Commission (FPSC), with the turnover of four of the five commissioner seats. The first significant new electric utility rate case to be addressed by this new constituted commission is for Gulf Power. On July 8, 2011, the utility filed for a $93.5 million base rate increase based on an 11.7% return on equity, with a decision expected from the FPSC by March 19, 2012. This base rate case is the first for the utility in over 10 years and its outcome may give an indication of the future direction of utility regulation in Florida. On February 15, 2012, the FPSC staff recommended a revenue increase of $62.3 million in 2012 with a subsequent $4 million revenue increase in 2013 and a return on equity of 10.25% (plus or minus 100 basis points. The FPSC is expected to vote in the rate case on February 27, 2012.

- New Vogtle nuclear construction project has increased Georgia Power's business risk profile

Southern's largest utility subsidiary, Georgia Power, is in the midst of an expensive, multi-year construction program to add two new Westinghouse AP 1000 nuclear generating units (Units 3 and 4), each representing 1,100 MW of capacity, to its existing Vogtle nuclear plant site near Waynesboro, Georgia. Georgia Power owns 45.7% of the new units, with the remainder to be owned by its current Vogtle partners: Oglethorpe Power Corporation (30%), Municipal Electric Authority of Georgia (22.7%), and the City of Dalton (1.6%). The total cost of the project is expected to be approximately $14 billion with Georgia Power's share at $6.1 billion with Unit 3 expected to become operational in 2016 and Unit 4 in 2017. Georgia Power hopes to finance a significant portion of the project with U.S. Department of Energy loan guarantees, the terms of which are still being negotiated.

On February 9, 2011, the Nuclear Regulatory Commission voted 4 to 1 to approve the issuance of the Combined Construction and Operating License (COL) for the new units, clearing the way for full construction. As of June 30, 2011, Georgia Power had incurred $1.7 billion of costs for the project, mostly for preliminary site work and for the purchase some long lead time equipment. The construction process now enters a more complicated and critical phase, with a higher risk of project delays and/or cost overruns. The company files a semi-annual construction monitoring report with the Georgia Public Service Commission (GPSC) each August and

February, with the next one to be filed on February 28, 2012.

In Moody's view, building a new nuclear plant is a complex and risky endeavor which has increased Georgia Power's business risk profile, although the Vogtle project appears to be a relatively manageable investment for a utility the size of Georgia Power and for a system as diverse as Southern. According to the company, the project continues to be managed within the currently certified budgeted amount of $6.113 billion. Although the schedule had been tracking a few months behind the targeted April 1, 2016 commercial operation date (COD) for Unit 3, the construction consortium has since submitted a revised schedule to the company that returned the COD to its original date. Both Georgia Power and the GPSC's Independent Construction Monitor have indicated that there will be significant challenges in meeting both the schedule and budget for a construction project of this magnitude.

- Substantial capital expenditure program, partly for environmental compliance, over next three years

As one of the largest coal-fired utility systems in the U.S., Southern is vulnerable to additional costs associated with EPA mandated environmental compliance regulations. Over the 2012-2014 time period, Southern projects $14 billion of base capital expenditures, of which $1.5 billion is for environmental compliance. However, the company faces additional environmental compliance capital expenditures of up to $4.4 billion over the same period related to still pending Utility MACT (MATS), water (316b), and coal combustion residual (ash) rules. While Moody's anticipates the continued recovery of environmental costs in rates, a significant portion of the capital program will be funded through debt issuances of approximately $10.4 billion (including $4.7 billion at Georgia Power) over the next three years, which could put pressure on Southern's consolidated financial metrics and balance sheet, depending on both the magnitude of the expenditures and the timing of implementation.

- Kemper IGCC plant increasing capital expenditures and business risk at Mississippi Power

In 2010, Mississippi Power decided to move forward on the construction of a 582 MW integrated coal gasification combined cycle or IGCC plant in Kemper County, Mississippi. Mississippi Power estimates the construction costs to be $2.4 billion, net of government construction cost incentives, and the plant is expected to be in operation by May 2014. Among the conditions imposed by the Mississippi Public Service Commission (MPSC) are a construction cost cap of $2.88 billion, 20% above the currently estimated capital cost; no CWIP recovery in 2010-2011 (AFUDC accrual only) with CWIP recovery thereafter; and regular, ongoing prudence reviews by the MPSC.

The plant's current cost estimate of $2.4 billion is almost equal to the total asset size of the utility, making it a substantial investment and a material undertaking for the company. Because of the project's size, Mississippi Power's capital expenditures have increased dramatically, rising from $247 million in 2010 to $818 million in 2011, $1.5 billion in 2012, and approximately $400 million in 2013, the bulk of which will be for the IGCC plant. Although IGCC technology has been utilized at other plants on a limited basis, the size, scope, and complexity of the project will materially increase business and concentration risk at the utility, especially during the construction phase. Duke Energy Indiana's Edwardsport IGCC plant, which is approximately 90% complete, has experienced substantial cost overruns, well in excess of the 20% cost overrun contingency approved for recovery for the Kemper plant by the MPSC. In addition, AEP has decided not to move forward on its Mountaineer IGCC project, partly because of cost concerns.

Mississippi Power files monthly construction status reports on the plant with the MPSC and, as of December 31, 2011, the project was on schedule and on budget, having spent approximately $827 million or 35% of the $2.4 billion certified amount. Mitigating the impact of this construction spending to some degree are $412 million of tax credits that were allocated to the project by the IRS, utilization of which can only occur if the plant is completed on time, making the construction schedule particularly important. Other risk mitigating factors include state ad valorem tax exemptions, pending Department of Energy loan guarantees, and an agreement by Southern Mississippi Electric Membership Association (SMEPA) to take a 17.5% ownership share of the plant, subject to MPSC approval. Additionally, on November 15, 2011 the company requested to implement a "certified new plant" (CNP) rider, which would allow a cash return on construction work in progress associated with the IGCC plant. If approved by the MPSC, Mississippi Power would recover $98 million based on a 10.70% return on equity in 2012.

- Potentially growing renewable energy business outside of the Southeast at Southern Power

Southern Power, Southern's competitive generation business, has a comparatively higher level of business risk than Southern's core retail regulated utility subsidiaries due to its lack of regulated cost recovery provisions and because its primary operations are in the competitive wholesale power markets. However, Southern Power exhibits a lower business risk profile than most other competitive wholesale generators due to a strategy of entering into long-term, fixed price contracts for the majority of its generation output with both unaffiliated wholesale purchasers as well as with Southern's regulated utilities, and its focus on the Southeast region. In addition, the market-based contracts under which capacity is sold contain provisions that pass the costs of fuel and related transportation through to the wholesale energy purchasers, thereby reducing SPC's financial and operating risk. SPC's capacity is highly contracted over the intermediate term. Southern Power is also benefiting from the current low natural gas price environment and has the potential to expand its natural gas fired generating capacity at several of its existing sites.

In recent years, Southern Power has begun to expand outside of its traditional Southeast regional focus with the acquisition of the 100 MW Nacogdoches biomass-fueled generating facility in Nacogdoches, Texas. Construction is currently underway and the plant is expected to be on line in 2012, with the output fully contracted to the City of Austin for 20 years. Southern Power has also completed a 30 MW solar project in New Mexico. Southern maintains a strategic alliance with Ted Turner, the largest individual landowner in the U.S., to develop and invest in additional similar scale solar photovoltaic projects in the U.S. in addition to developing other solar renewable technologies. While currently modest, significant additional investments in renewable energy outside of the Southeast has the potential to increase Southern Company's overall business and operating risk profile.

Liquidity

Southern Company's liquidity profile is supported by the underlying cash flows of its four regulated electric operating subsidiaries and wholesale generation business; an unused bank credit facility at the parent company level; and a sufficient cash position as of September 30, 2011. Southern maintains a $1 billion five year credit facility at the parent company that expires in 2016. The credit facility provides liquidity support for Southern's commercial paper program and can be used for other short-term financing needs. The credit facility has a covenant which limits Southern's debt to capital (excluding trust preferred securities) to 65% and there are no material adverse change representations for new borrowings. As of September 30, 2011, Southern was in compliance with its financial covenant.

Southern had approximately $1.5 billion of cash on hand and $132 million of commercial paper and short-term borrowings outstanding on a consolidated basis as of September 30, 2011. Moody's anticipates dividend contributions from its subsidiaries will be in the range of $1.8 billion to $2.0 billion in 2012. Both Georgia Power and Mississippi Power will also require significant equity infusions to help meet construction expenditures over the next several years.

Southern's utility subsidiaries and Southern Power each maintain their own bank facilities to support short-term liquidity needs. Consolidated unused credit facilities are approximately $5.13 billion as of September 30, 2011 (with $1.8 billion providing liquidity support to the utilities' pollution control revenue bonds). Of these, $316 million expire in 2012, $60 million expire in 2013, $860 million expire in 2014, and $3.8 billion expire in 2016.

Southern and its subsidiaries maintain contracts for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, and energy price risk management that could require collateral in the event of a ratings downgrade. In the event of an unsecured rating downgrade of certain subsidiaries to Baa3, the maximum collateral requirements would be $606 million as of September 30, 2011. If credit ratings are downgraded to below investment grade, the potential maximum collateral requirement would be $2.8 billion. Generally, collateral could be provided by a Southern Company guaranty, letter of credit, or cash. As of September 30, 2011, Southern had approximately $1.89 billion of consolidated long-term debt maturities over the twelve months ending September 30, 2012, and a total of $2.9 billion of long-term debt due over the 2012-2013 time period.

Rating Outlook

The stable rating outlook reflects Moody's expectation that Southern Company's utility regulatory environments will remain credit supportive; that there will be no substantial delays or cost overruns at either the Vogtle nuclear or Kemper IGCC construction projects; that costs resulting from new environmental regulations will be manageable and recovered in rates without significant regulatory lag or substantial deferrals; and that growth of its renewable energy business outside of its region will remain modest.

What Could Change the Rating - Up

An upgrade is unlikely while two of its utility subsidiaries are engaged in major new construction projects. Ratings could be raised, however, if there is significant progress on the construction of these two projects and they remain on schedule and on budget, if one or both of its largest utility subsidiaries, Alabama Power or Georgia Power, is upgraded; or if consolidated financial metrics show sustained improvement, including CFO pre-W/C interest coverage above 4.5x and CFO pre-W/C to debt above 22%, after adjusting for accelerated cash flow benefits derived from bonus depreciation.

What Could Change the Rating - Down

The ratings could be downgraded if either Alabama Power or Georgia Power's ratings are lowered; if there are significant delays or cost overruns on the Vogtle nuclear project; if there is significant additional debt issued at the parent company level; if major new environmental costs are incurred that are not recovered on a timely basis; or if consolidated metrics show a sustained decline, including CFO pre-W/C interest coverage below 4.0x and CFO pre-W/C to debt below 18% for an extended period.

Rating Factors

Southern Company (The)

Regulated Electric and Gas Utilities Industry [1][2]	**Current 12/31/2010**		**Moody's 12-18 month Forward View* As of February 2012**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		A		A
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (5%)		A		A

b) Generation and Fuel Diversity (5%)		Ba		Ba
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		A		A
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	4.7x	A	5.5 - 6.0x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	19.2%	Baa	20 - 25%	A/Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	12.5%	Baa	15 - 20%	A/Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	48.9%	Baa	45 - 47%	Baa
Rating:				
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		Baa1		Baa1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2010(L); Source: Moody's Financial Metrics

Global Credit Research
Credit Opinion
30 SEP 2011

Credit Opinion: Vectren Utility Holdings, Inc.

Vectren Utility Holdings, Inc.

Indianapolis, Indiana (State of), United States

Ratings

Category	Moody's Rating
Outlook	Stable
Bkd Sr Unsec Bank Credit Facility	A3
Senior Unsecured	A3
Bkd Commercial Paper	P-2
Indiana Gas Company, Inc.	
Outlook	Stable
Senior Unsecured	A3
Southern Indiana Gas & Electric Company	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured	A1

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Key Indicators

[1]
Vectren Utility Holdings, Inc.

	2Q11 LTM	2010	2009	2008
Adj CFO (pre w/c) + Interest / Interest	**5.2x**	**5.5x**	**5.4x**	**5.1x**
Adj CFO (pre w/c) / Debt	**25.9%**	**27.2%**	**26.9%**	**25.2%**
Adj CFO (pre w/c) - Dividends / Debt	**19.0%**	**21.0%**	**21.0%**	**19.5%**
Debt / Capitalization	**42.7%**	**44.1%**	**44.9%**	**47.8%**

[1] All ratios are calculated using Moody's Standard Adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

- Credit metrics and financial performance that solidly position VUHI within its rating category

- Supportive regulatory environments with constructive rate designs

- Unregulated affiliates in complementary businesses

- Well positioned to comply with new environmental mandates

Corporate Profile

Vectren Utility Holdings Inc. (VUHI; A3 senior unsecured, stable outlook) is an intermediate holding company of Vectren Corporation (Vectren; unrated) based in Evansville, Indiana. VUHI is the holding company of Vectren's regulated utility subsidiaries, Indiana Gas Company (IGC; A3 senior unsecured, stable outlook), Southern Indiana Gas & Electric Company (SIGECO; A3 senior unsecured issuer rating, stable outlook), and Vectren Energy Delivery of Ohio (VEDO; unrated). VUHI's utility subsidiaries provide electric service in southern Indiana and natural gas distribution in Indiana and Ohio. VUHI has over 1.1 million customers in Indiana and Ohio, and electric and gas operations have made roughly equal contributions to earnings over the past three years.

DETAILED RATING CONSIDERATIONS

CREDIT METRICS AND FINANCIAL PERFORMANCE THAT SOLIDLY POSITION VUHI WITHIN ITS RATING CATEGORY

VUHI's credit metrics are solidly positioned for its rating category. Over the last several years rate cases at all three utilities in addition to improved rate recovery mechanisms and rate designs have led to a sustained improvement in financial metrics. CFO pre-working capital interest coverage was 5.2 times in the 12 months ended June 30, 2011 and 5.5 times in 2010 while CFO was 26% and 27% in the same periods. Moody's ratings are based on VUHI's metrics remaining around these levels, with CFO pre-working capital interest coverage in the low 5 times range and CFO pre-working capital to debt in the low to mid-20% range.

SUPPORTIVE REGULATORY ENVIRONMENTS WITH CONSTRUCTIVE RATE DESIGNS

VUHI's utility operations are in Indiana (gas and electric) and Ohio (gas), both supportive regulatory environments with constructive rate designs and allowed ROEs around the national average. Major capital investments have received favorable regulatory treatment with timely recovery through riders. VUHI maintains good relationships with both utility commissions.

In the most recent electric rate case for SIGECO announced in April 2011, the company was awarded a net rate increase of $29 million with an authorized ROE of 10.4%, the same ROE that the company received in its 2007 rate case. This was a favorable outcome for the company, as it was very close to the revised amount of $34 million with a 10.7% ROE that the company requested in July 2010. In its decision, the Commission attributed most of the increase to the infrastructure investments the company has made over the past few years. However, they also noted that the rate increase was compensating the company for decreased demand from traditional manufacturing and lower wholesale power margins (WPM) resulting from lower MISO prices that reflected decreased demand and increased production from gas-fired facilities.

Also related to the lower wholesale power margins, the Commission agreed to decrease the WPMs imputed in its revenue requirement to $7.5 million from $10.5 million, and to continue the 50/50 sharing arrangement between customers and investors. As part of their request, SIGECO had also requested electric decoupling; however, the Commission denied this request arguing that decoupling was appropriate for gas but not a vertically integrated electric utility. The Commission did indicate that they would continue to explore with SIGECO mechanisms for cost recovery related to losses from increased energy efficiency.

VUHI's gas operations in Indiana and Ohio benefit from gas cost recovery, bad debt trackers, and capital expenditure recovery for bare steel and cast iron replacement. Decoupling has been achieved in Indiana through weather normalization and conservation tariffs, and a straight-fixed-variable rate design in Ohio which was fully implemented in February 2010.

VUHI's electric operations at SIGECO in Indiana benefit from fuel cost and purchased power recovery mechanisms plus the recovery of environmental CWIP, reliability enhancement, and demand side management expenses through trackers.

UNREGULATED AFFILIATES IN COMPLEMENTARY BUSINESSES

VUHI accounted for approximately 93% of earnings for Vectren in 2010, much higher than than 80% registered in 2009. The remaining component of Vectren is Vectren Enterprises. The large shift in the earnings share of utilities from 2009 to 2010 was due to losses at ProLiance Energy ($7.9 million loss), the energy marketing business at Vectren Enterprises which is a joint venture between Vectren (61%) and Citizens Energy plus write downs in investments in two legacy businesses ($7.4 million in write downs). ProLiance's loss is primarily attributed to lower natural gas prices and firm transportation spreads. Although ProLiance is pursuing strategies to cut costs and increase sales, Vectren has indicated that they expect to continue to see some losses until they are able to renegotiate the approximately 50% of contracts that expire over the next 5 years.

Vectren Enterprises is involved in four primary businesses areas: Energy Marketing (including ProLiance), Coal Mining, Infrastructure Services, and Energy Services. Each of the businesses is tangentially related to Vectren's core utility business with VUHI and its subsidiaries usually being a major, if not the largest, customer. This heavy reliance of the unregulated businesses on VUHI helps mitigate the inherent risks of the unregulated businesses on Vectren as a whole.

To offset the decline at ProLiance, Vectren is interested in expanding its Infrastructure Services business, which provides underground pipeline construction and repair services for natural gas, water, and wastewater companies. In line with this strategy, in March 2011 Vectren acquired Minnesota Limited, which provides underground pipeline construction and repair services for natural gas and petroleum transmission companies.

Vectren does not have any explicit ring-fencing provision in place for its utility operations. Instead, Vectren utilizes an organizational structure that silos the utilities under an intermediate holding company (VUHI) with its own credit facility. Vectren Enterprises is self-financing and has its own financing vehicle (Vectren Capital) and credit facility ($250 million expiring September 2013 with two, one-year extensions). Neither Vectren nor Citizens guarantees the debt at ProLiance Energy with the debt having no recourse to Vectren.

Vectren has not made any capital contributions to ProLiance Energy since 1997.

WELL POSITIONED TO COMPLY WITH NEW ENVIRONMENTAL MANDATES

VUHI is well positioned to comply with the new Cross State Air Pollution Rule (CSAPR), since capital investment over the past 10 years has produced a generation fleet that is 100% scrubbed for sulfur dioxide, 90% controlled for nitrous oxide, and substantially controlled for particulate matter and mercury. The company estimates very minimal expenditures on slight modifications to existing control technology. If their estimates are correct, the slight levels of capital expenditures would not impact the credit metrics. In addition, the company believes that these expenditures will qualify for recovery through Indiana State Senate Bill 251, signed in May 2011, which authorizes recovery (80%) and deferral (20%) of investments made to comply with federal mandates.

Liquidity Profile

VUHI has an adequate liquidity profile. VUHI has a $600 million commercial paper program backed by a $350 million credit facility issued in September 2011 that expires in September 2013 with two, one-year extensions. As of June 30, 2011, VUHI had $42 million in commercial paper outstanding and a cash balance of $13 million. The credit facility and commercial paper are fully guaranteed on a joint and several basis by IGC, SIGECO, and VEDO. VUHI was in compliance with its facility's 65% debt to capitalization covenant at August 12, 2011.

Operating cash flow of about $350 million to $400 million going forward should be sufficient to cover capital expenditures in the $230-$240 million range. Short-term borrowings are typically used during the gas injection period before the winter heating season. The next maturity for VUHI is $250 million of debt due on December 1, 2011. VUHI is funding part of this maturity through a $150 million private placement of three tranches maturing from 10 to 30 years that was issued in April 2011 and to be drawn on November 30, 2011. The remainder of the $100 million will be funded through cash flows, bonus depreciation, and short term debt. Moody's views VUHI's use of bonus depreciation to deleverage as credit positive. In addition to using bonus depreciation to deleverage, VUHI will apply $25 million of bonus depreciation as an employer contribution to pension obligations, which Moody's also views as credit positive.

Rating Outlook

The stable outlook is based on the credit metrics that solidly position VUHI in its rating category as well as the supportive regulatory environment, as evidenced by the positive outcome of SIGECO's recent electric rate case.

What Could Change the Rating - Up

VUHI's ratings could be upgraded if there is a sustained improvement in its financial performance, including CFO pre-working capital coverage around the 6 times range and CFO pre-working capital to debt in the high 20% range.

What Could Change the Rating - Down

VUHI's ratings could be downgraded if there is a sustained deterioration in its financial performance, including CFO pre-working capital coverage below the mid 4 times range and CFO pre-working capital to debt below the 20% range.

Other Considerations

The ratings at SIGECO and IGC are closely tied to VUHI's rating due to the full and unconditional, joint and several guarantees currently provided by VUHI's direct subsidiaries. Any material change at SIGECO, IGC, or VEDO would result in a change in the overall creditworthiness of VUHI.

Rating Factors

Vectren Utility Holdings, Inc.

Regulated Electric and Gas Utilities [1]	**LTM Jun-30-2011**		**Moody's 12-18 month Forward View As of September 30, 2011***	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory framework		Baa		Baa
Factor 2: Ability to Recover Cost and Earn Returns (25%)				
a) Ability to recover Cost and Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position		Baa		Baa

b) Generation and Fuel Diversity		Baa		Baa
Factor 4: Financial Strength, Liquidity, & Metrics (40%)				
a) Liquidity		Baa		Baa
b) CFO (pre w/c) + Interest / Interest	5.2x	A	5.2x-5.7x	A
c) CFO (pre w/c) / Debt	25.9%	A	25%-27%	A
d) CFO (pre w/c) - Dividends / Debt	19.0%	A	19%-21%	A
e) Debt / Capitalization	42.7%	A	41%-44%	A
Rating:				
Indicated Rating from Grid		A3		A3
Actual Rating Assigned		A3		A3

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments.

MOODY'S INVESTORS SERVICE

Global Credit Research
Credit Opinion
8 MAR 2012

Credit Opinion: Washington Gas Light Company

Washington Gas Light Company

Washington, D.C., United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Senior Unsecured	A2
Pref. Stock	Baa1
Bkd Commercial Paper	P-1
Parent: WGL Holdings, Inc.	
Outlook	Stable
Commercial Paper	P-2

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Key Indicators

[1]
Washington Gas Light Company

	2011	**2010**	**2009**	**2008**
(CFO Pre-W/C + Interest) / Interest Expense	**5.9x**	**6.8x**	**6.2x**	**5.6x**
(CFO Pre-W/C) / Debt	**27%**	**32%**	**27%**	**22%**
(CFO Pre-W/C - Dividends) / Debt	**19%**	**24%**	**20%**	**16%**
Debt / Book Capitalization	**38%**	**38%**	**42%**	**45%**
EBITA Margin %	**14%**	**16%**	**14%**	**14%**

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Constructive regulatory environments provide opportunity to earn a just return

Increased capital spending over the next five years

Credit metrics pressured by a sizeable capital expenditure program

Parent non-regulated activities remain significant

Corporate Profile

Washington Gas Light Company (Washington Gas: A2 senior unsecured) is a regulated utility that sells and delivers natural gas to approximately 1.1 million customers in the District of Columbia (approximately 14% of its customers) and adjoining areas in Maryland

(41%) and Virginia (45%).

Washington Gas is a wholly-owned subsidiary and the core business of WGL Holdings (WGL: Prime-2). WGL's other businesses include an retail energy marketing segment, which sells natural gas and electricity directly to retail customers; a commercial energy systems segment, which provides design-build energy solutions including commercial solar, energy efficiency and combined heat and power projects to government and commercial clients; and a wholesale energy solutions segment, which manages and optimizes natural gas storage and transportation assets.

During fiscal year 2011 (which ended September 30, 2011), Washington Gas accounted for approximately 47% of WGL's consolidated revenues, 89% of consolidated assets and generated 79% of consolidated cash from operations pre-changes to working capital (CFO pre-W/C) .

The largest of WGL's non-utility business is WGL's retail energy marketing business. During 2011, this business produced slightly more than $1.4 billion of revenue and realized gross margins of $112 million compared to slightly less than $1.4 billion and $83 million, respectively, for fiscal 2010. The year-over-year increase in realized gross margin was driven by a combination of increased volumes and pricing. WGL anticipates pricing to be flat in fiscal 2012 but that a modest increase in electric volumes will cause realized gross margins to increase modestly to approximately $115 million.

Recent Events

On March 1st, 2012, Capitol Energy Ventures Corp., a subsidiary of WGL, entered into an agreement with UGI Energy Services and Inergy Midstream L.P. to jointly market and develop a 200-mile interstate pipeline known as the Commonwealth Pipeline. As proposed, the pipeline is expected to deliver at least 800,000 dekatherms of natural gas per day and go into service in 2015, with an estimated cost of $1 billion to be split evenly among the sponsors. At this time, all parties have agreed to share the costs associated with the joint development effort, and will make future decisions pending the results.

This potential sizable investment, the construction of which is uncertain at this time, is not currently factored in WGL or Washington Gas' rating.

Rating Rationale

Moody's evaluates Washington Gas' consolidated financial performance relative to the Regulated Electric and Gas Utilities rating methodology published in August 2009 (the Methodology) and as depicted in the grid below, Washington Gas' indicated rating under this methodology is an A2, compared to its current A2 senior unsecured rating. The indicated rating as of December 31, 2011 considers Washington Gas' financial performance based on a three-year historical average.

Washington Gas' senior unsecured A2 rating is supported by a historically strong balance sheet and financial metrics coupled with its ability to recover operating expenses in a timely manner while earning a reasonable return on equity. Upward movement in the utility's rating, however, is limited by its sizable capital expenditure program and WGL's growing non-regulated activities. Washington Gas benefits from an economically diverse and largely residential and small commercial customer base which has historically mitigated the effect of economic downturns.

Detailed rating factors are as follows:

Constructive regulatory environment

As discussed in the Methodology, the credit supportiveness of the regulatory framework under which a utility operates is a critical rating factor. Washington Gas is regulated by the District of Columbia Public Service Commission (DCPSC), the Maryland Public Service Commission (MPSC) and the Virginia State Corporation Commission (VSCC). These jurisdictions have historically been fairly predictable and supportive in providing local gas distribution utilities an opportunity to earn a just and reasonable rate of return and to recover reasonable operating expenses. Additionally, gas cost recovery mechanisms, as approved in jurisdictional tariffs, allow Washington Gas the ability to recover the cost of natural gas to serve its customers. Lastly, rate decoupling mechanisms have been implemented in Maryland and Virginia. Moody's views decoupling mechanism favorably as they typically provide for predictable revenue streams.

Specifically, Washington Gas implemented Revenue Normalization Adjustment (RNA) billing factors in Maryland in October 2005 that allow the company to recover anticipated revenues from customers regardless of changes in weather and customer usage. The RNA billing mechanism in Maryland is designed to stabilize the level of net revenues collected from customers by reducing the effect of variations in customer usage caused by variations in weather from normal levels and other factors such as conservation.

On March 26, 2010 the VSCC issued an order approving a decoupling rate mechanism for residential customers and six residential energy efficiency programs and the cost recovery mechanism for those programs. Washington Gas began applying the decoupling mechanism in Virginia in July 2010.

Effective November 2011, the MPSC authorized Washington Gas to raise rates by approximately $8.4 million, effective November 14, 2011 based on a 9.6% allowed return on equity (ROE) and an equity ratio of 57.88%. This compares to a 10% allowed ROE and an equity ratio of 53% that the MPSC granted Washington Gas in its previously rate case that occurred in 2007.

On January 31, 2011, Washington Gas filed a request with the VSCC for a base rate increase of $29.6 million. On November 30, 2011, Washington Gas filed a stipulation to reflect settlement terms to which the company, the VSCC Staff and other parties agreed. In the stipulation, the settling parties agreed to a $20 million rate increased based on a 9.75% ROE. A commission decision is pending.

On February 29, 2011, Washington Gas filed a request with the DCPSC to increase rates by $29 million based on a 10.9% ROE. This rate case complies with a November 2011 order by, the DCPSC that initiated an earnings investigation into Washing Gas' base rate, and required the company to file a rate case. Washington Gas' last rate case was settled in 2007, when the DCPSC authorized a non-unanimous settlement for a rate base increase of $1.4 million, but made no specification for authorized rate of return. The DCPSC did note a 10% ROE and that an 8.12% overall return would be used for purposes of computing carrying costs.

While all of Washington Gas' customers are eligible to choose to purchase their natural gas from unregulated third-party marketers, only approximately 162,000 customers have chosen to do so. This does not impact Washington Gas' net income as the company does not make a margin on the sale of natural gas, but still benefits from delivery and distribution charges to these customers..

From the perspective of our rating methodology, Washington Gas is scored at the Baa level for Factor 1: Regulated Framework. We score the company at A for Factor 2: Ability to Recover Costs and Earn Returns due in part to the implementation of decoupling mechanisms in Maryland and Virginia. This scoring also considers Washington Gas' ability to earn close to its allowed returns evidenced by earned ROEs of approximately 10% in each of the last three years.

Increased capital spending

Washington Gas' capital expenditures are anticipated to remain elevated over the next three years. Specifically, the company estimates its capital expenditures to be approximately $200 million annually in each of 2012, 2013 and 2014 compared to $180 million in 2011, $125 million in 2010, and $134 million in 2009. Our expectation is that the company's capital expenditures will be funded in part through the issuance of debt. Specifically, we anticipate Washington Gas' debt levels to increase by approximately $170 million during this three year time period. Its unadjusted debt as of December 31, 2011 was $699 million.

Approximately $50 million of Washington Gas' capital expenditures in 2011 and $24 million in 2012 are directly attributable to the development and construction of new office and operations facilities that are anticipated to open in April. Another driver for the increased capital expenditure program is pipe replacement programs planned for Virginia and Maryland.

The pipe replacement planned for Virginia is being driven by the Steps to Advance Virginia's Energy or SAVE Plan. The SAVE Plan, enacted in 2010, allows gas LDC's operating in Virginia to recover certain costs associated with the construction of replacement infrastructure aimed at enhancing public safety. The LDC, however, must submit a plan for approval by the VSCC prior to construction. In April 2011, the VSCC issued an order approving Washington Gas' proposed 5-year plan for a total of $116.5 million in expenditures for four replacement programs. Also approved was a SAVE rider to recover the costs of the replacement programs, with rates effective May 1, 2011.

On September 1, 2011, Washington Gas filed an application with the VSCC for approval to implement its 2012 SAVE rider, with an estimated amount of $29.8 million for the entire duration of 2012. A commission decision is pending.

While the MPSC authorized Washington Gas to implement an initial 5-year phase of an accelerated pipe replacement plan, it denied the company's request of a separate cost recovery mechanism. This will likely cause Washington Gas to increase the frequency of its rate request filings in Maryland.

Credit metrics pressured by sizeable capital expenditure program

Washington Gas' recent financial performance has been robust and positions the company solidly within its rating category. Specifically, its ratio of cash from operations pre-working capital (CFO pre W/C) to debt, CFO pre-W/C interest coverage and debt capitalization were 27.1%, 5.9 times and 37.5% respectively, for fiscal year 2011 compared to 31.7%, 6.8 times and 38.1%, respectively, for fiscal year 2010. Fiscal 2010 results, however, were boosted by an accounting change relating to the treatment of repairs resulting in a one-time $59 million federal tax refund received in July of 2010. Absent this change, financial metrics in 2011 were comparable with 2010 performance.

Washington Gas' near-term financial metrics are expected to be lower than historical levels due primarily to increased debt load. Specifically, metrics for 2012 are estimated to include CFO pre-W/C to debt of approximately 24% and interest coverage of 5.8 times and 22% and 5.5 times, respectively, in fiscal 2013.

Parent's non-regulated activities

While WGL appears to manage the risk profile of its unregulated activities appropriately, the business has continued to grow in size and scope and has sizable liquidity requirements. There are limited ring-fencing mechanisms to provide separation between WGL and Washington Gas and, therefore, WGL's significant and growing exposure to non-regulated activities constrains Washington Gas' rating.

Liquidity

Washington Gas maintains a $300 million syndicated credit facility that expires in August 2012. The sole financial covenant ratio imposed by the agreement requires that consolidated debt to consolidated capitalization not exceed 65% at anytime. Washington Gas currently has ample headroom under this covenant.

The credit facility backstops the company's $300 million commercial paper program. Due to the seasonality of the company's short term borrowings, peaks typically occur during the winter months with lows reached in early summer. Washington Gas had $65 million of short-term debt outstanding at December 31, 2011 compared to $17 million at December 31, 2010.

Washington Gas' debt maturities are reasonably spaced out with maturities of approximately $50 million and $37 million in calendar years 2012 and 2013, respectively.

WGL's short-term debt outstanding at December 31, 2011, excluding Washington Gas, was approximately $163 million compared to $76 million the prior comparable period. WGL has a separate $400 million syndicated credit facility that also expires in August 2012 to support its liquidity needs.

In mid-February, WGL and Washington Gas launched syndication efforts for two new 5-year revolving credit facilities that they anticipate finalizing this month.

Moody's expects Washington Gas to continue to prudently manage its liquidity, including the expiration of the credit facilities in less than one year. Within the framework of the Methodology, Washington Gas maps to a factor within the Ba range for Factor 4 - Liquidity. However, this factor is expected to increase to the Baa range once the facility has been renewed.

Rating Outlook

The rating outlook is stable. The stable outlook assumes continuing support from its regulators.

What Could Change the Rating - Up

Upward rating movement is not expected in the medium-term. Longer term, we would likely need to see decreased non-regulated activities at WGL combined with the utility achieving CFO pre-W/C to debt of greater than 26% on a sustainable basis to consider an upgrade.

What Could Change the Rating - Down

Ratings may be negatively impacted if capital expenditures pressure cash flow and debt levels such that the utility's ratio of CFO pre-W/C to debt falls below 20% on a sustainable basis or if WGL significantly increases the risk profile and liquidity requirements of its non-regulated operations.

Rating Factors

Washington Gas Light Company

Regulated Electric and Gas Utilities Industry [1][2]	**Current 12/31/2011**		**Moody's 12-18 month Forward View* As of March 6, 2012**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		Baa		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (10%)		A		A
b) Generation and Fuel Diversity (0%)				
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		A		A
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	6.3x	Aa	5.0x-6.0x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	28.8%	A	22-24%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	21.0%	A	13-15%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	39.3%	A	35-42%	A

Rating:				
a) Indicated Rating from Grid		A2		A3
b) Actual Rating Assigned		A2		A2

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] Source: Moody's Financial Metrics

Global Credit Research
Credit Opinion
12 DEC 2011

Credit Opinion: Wisconsin Energy Corporation

Wisconsin Energy Corporation

Milwaukee, Wisconsin, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	A3
Senior Unsecured	A3
Jr Subordinate	Baa1
Bkd Commercial Paper	P-2
Wisconsin Electric Power Company	
Outlook	Stable
Issuer Rating	A2
Senior Unsecured	A2
Pref. Stock	Baa1
Commercial Paper	P-1
Elm Road Generating Station Supercritical	
Outlook	Stable
Senior Unsecured	A2
Wisconsin Gas LLC	
Outlook	Stable
Senior Unsecured	A2
Commercial Paper	P-1
Wisconsin Energy Capital Corporation	
Outlook	Stable
Bkd Senior Unsecured	A3

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Key Indicators

[1]
Wisconsin Energy Corporation

	LTM	**2010**	**2009**	**2008**
(CFO Pre-W/C + Interest) / Interest Expense	**5.0x**	**4.8x**	**5.0x**	**5.6x**
(CFO Pre-W/C) / Debt	**22%**	**20%**	**20%**	**23%**
(CFO Pre-W/C - Dividends) / Debt	**18%**	**16%**	**17%**	**20%**
Debt / Book Capitalization	**49%**	**50%**	**51%**	**53%**

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Supportive regulatory environment allows for above-average returns and timely cost recovery

Forward-looking capital spending program peaks in 2011 but remains significant

Strong consolidated financial metrics

Increasing dividend payout

Free cash flow positive in 2012-2014 timeframe

Business Profile

Wisconsin Energy Corporation (WEC: A3 senior unsecured) is a Milwaukee-based holding company that conducts operations in an energy segment and, to a much lesser extent, a non-energy segment. The non-energy segment primarily invests in real estate and holds $86 million in assets. WEC also has 23% ownership interest in the American Transmission Company (ATC: A1 senior unsecured).

The energy segment consists of Wisconsin Electric Power Company (WEPCO: A2 senior unsecured), Wisconsin Gas LLC (Wisconsin Gas: A2 senior unsecured) and all the Power the Future (PTF) related assets. Collectively, these companies serve approximately 1.1 million electric customers in Wisconsin and Michigan's Upper Peninsula, and more than one million natural gas customers in Wisconsin.

WEC's strategy since 2000 has revolved around PTF, a multi-billion dollar build-out program focused on improving the supply and reliability of electricity in Wisconsin. The key component of PTF has been the construction of 2,320 megawatts of new generating capacity in Wisconsin at a cost of approximately $2.7 billion that was completed earlier this year.

Rating Rationale

Moody's evaluates WEC's financial performance relative to the Regulated Electric and Gas Utilities rating methodology published in August 2009. WEC's indicated rating as depicted in the grids below is A3, the same as its assigned senior unsecured rating. The indicated grid ratings consider WEC's consolidated financial performance based on a three-year historical average and 18-24 month prospective basis.

While some of WEC's financial metrics are slightly weak for the rating category, its A3 senior unsecured rating is underpinned by an above average supportive regulatory environment as well as a conservative business and financial strategy.

DETAILED RATING CONSIDERATIONS

Minimal regulatory risk associated with Power the Future (PTF)

Oak Creek Unit 1, a 615-megawatt coal-fired generating facility was placed into service in February 2010 and Oak Creek Unit 2, a similarly-sized facility, commenced operations in January 2011. Oak Creek Unit 2 was the final piece in WEC's $2.7 billion PTF construction program. Two 545-megawatt gas-fired generating facilities, Port Washington Unit 1 and Port Washington Unit 2, began commercial operation in July 2005 and May 2008, respectively.

All four generating units are leased to WEPCO under long-term leases that have been approved by the Public Service Commission of Wisconsin (PSCW). The leases are designed to recover the capital costs of the plants including a strong 12.7% fixed return on equity that provides highly visible earnings and cash flow streams. WEPCO, under Wisconsin state legislation, is allowed to recover lease payments through rates charged to its Wisconsin retail electric customers. The legislation prevents future regulatory commissions from modifying or terminating terms of the approved lease, thereby providing statutory protection from any potential regulatory reversal.

Approximately 40% of WEC's consolidated operating income during the nine months ended September 30, 2011 was derived from the PTF leases.

Supportive regulatory environment allows for above-average returns and cost recovery

The company estimates that approximately 88% of its electric revenue (and 100% of its natural gas revenue) are regulated by the Public Service Commission of Wisconsin (PSCW), 7% by the Michigan Public Service Commission and the balance by the FERC.

Moody's ranks Wisconsin in the top tier of regulatory jurisdictions in the United States. Our assessment is based on a stable regulatory framework that underpins an above-average ability to recover costs and investments in a timely manner. Regulatory features supporting Moody's opinion include the requirement for utilities to file general rate cases on a bi-annual basis based on forward-looking test periods which significantly diminish regulatory lag. Practices used by the PSCW in its ratemaking that are considered credit positive include granting authorized equity returns that slightly exceed national averages along with equity-strong capital structures. WEPCO is provided the opportunity to earn 10.4% return on equity based on a 53.5% regulatory common equity ratio. WEC has historically earned a strong rate of return; its consolidated earned return on equity for the twelve months ended September 30, 2011 was approximately 13%. For these reasons and those cited above, WEC maps to rating factors of A for both Factor 1: Regulatory Framework and Factor 2: Ability to Recover Costs and Earn Returns within Moody's methodology.

In May 2011, WEPCO and Wisconsin Gas filed with the PSCW to initiate electric and gas proceedings. In their filing, they stressed the "still fragile economic recovery" in Wisconsin, and proposed an alternative to the traditional rate cases that commits to no rate increases in 2012, in exchanges for a number of concessions regarding WEPCO's regulatory costs and commitments. The PSCW accepted the company's proposal in October 2011. WEPCO and Wisconsin Gas are expected to file a rate case in 2012 for new rates to be effective in January 2013.

Geographic diversification limited primarily to one state

WEC's geographic diversification is limited to Wisconsin and, to a lesser extent, the Upper Peninsula of Michigan. Moody's factors in the range of services the company provides including gas and electricity distribution, power generation and an indirect ownership-stake in the American Transmission Company LLC (ATC: A1 senior unsecured), in scoring WEC to a Baa rating factor for Factor 3: Market Position.

The company's sources for electric energy supply is somewhat diverse. Over the near-term, WEPCO expects to generate approximately 56% from coal-fired generation, 35% under long-term power purchase agreements (PPA's), 7% from its own gas-fired generation and 2% from either wind or hydroelectric generating facilities. Power purchased under PPA's is primarily from the Point Beach Nuclear Station, which the company sold to an affiliate of FPL Energy Group in 2007. As part of that transaction, WEPCO and the buyer entered into a long-term PPA (which extends through 2030 for Unit 1 and 2033 for Unit 2) which requires WEPCO to purchase all the energy produced at the nuclear station at predetermined prices.

Given the diversity of these sources, WEC is scored to a Baa rating factor for Factor 3: Generation and Fuel Diversification.

Forward-looking capital spending program peaks in 2011 but is expected to remain significant thereafter driven by spending on renewable energy requirements and pollution control equipment

WEC's near-term capital expenditures are expected to peak in 2011 and reduce thereafter. The majority of WEC's capital expenditures are at its electric and gas utilities. The expected combined expenditures over the next three years for these regulated entities are $836 million in 2011, $705 million in 2012 and $678 million in 2013. Consolidated capital expenditures totaled approximately $800 million in 2010, $815 million in 2009 and $1,134 million in 2008.

The bulk of the near-term capital spending is focused on projects that will allow the company to remain in compliance with Wisconsin's renewable portfolio standard requirements and the recent updated EPA requirements with the installation of pollution control equipment at existing electric generating stations.

Wisconsin legislation requires utilities operating in the state to meet certain minimum requirements for renewable energy generation. Specifically, for the years 2010 through 2014, WEPCO is required to increase its percentage of total retail energy sales provided by renewable sources to 4.27% from 2.27%. Moreover, by the year 2015, the percentage increases to 8.27%. According to WEPCO, its renewable energy percentage as of December 31, 2010 was 4.27%.

To meet the 2015 requirement, WEPCO has undertaken construction of two renewable power projects. Construction of the 162-megawatt Glacier Hills Wind Park commenced in May 2010 and is expected to be completed by year-end at an estimated cost between $360-370 million. Glacier Hills represents the company's second wind-farm; the 145 -megawatt Blue Sky Green Field wind project achieved commercial operation in 2008.

In addition, the company has received regulatory approval and has commenced construction on a biomass-fueled power plant at Domtar Corporation's Rothschild, Wisconsin paper mill site. Wood, waste and sawdust will be used to produce approximately 50 MW electricity and will also support Domtar's sustainable papermaking operations. The expected cost of the plant is approximately $245-255 million, and is expected to be completed during the fall of 2013 which will diversify the company's portfolio of renewable generation.

WEPCO's other source of renewable energy is from 13 operating hydroelectric plants with a combined capacity of 88 megawatts.

Another significant construction project involves the installation of environmental control equipment at WEPCO's coal-fired Oak Creek Station units 5-8 in order to facilitate compliance with various EPA standards. Construction began in July 2008 and is expected to be completed during 2012 at an estimated cost of $900 million.

Increasing dividend payout

Throughout the PTF construction phase, WEC kept its dividend payout at approximately 40-45%, levels significantly below the industry average of 65%. Given that this material expansion stage has been completed, WEC's Board of Directors in early 2011 approved a dividend policy that calls for a payout ratio of 60% of earnings in the year 2015 in an effort to bring it more in-line with the industry average. To that end, WEC announced in December plans to raise the quarterly dividend to 30 cents a share in the first quarter of 2012 from 26 cents currently. Based on 2011 earnings guidance, the expected 2012 dividend payout ratio would be 56%.

Strong consolidated financial metrics

WEC's consolidated financial performance remains strong. Specifically, the company's key ratios of consolidated cash from operations prior to changes in working capital (CFO pre-W/C) to debt and consolidated interest coverage were approximately 22% and 5 times, for the twelve months ended September 30, 2011, and compare favorably to 20% and 4.8 times, respectively, at December 31, 2010. Going forward, we expect WEC's key metrics to remain in excess of 20% and 4 times through at least 2013.

Even with an increasing dividend payout ratio, WEC expects to generate a considerable amount of free cash flow during the 2012-2014 timeframe due to strong operating cash flows (driven in part to the impact of bonus depreciation) and a reduction in capital expenditures. Free cash flow may be used to repurchase common equity and retire debt.

WEC estimates $100 million in cash benefits from bonus depreciation in 2011 and $200 million in 2012.

Liquidity

WEC maintains a three-year $450 million revolving credit facility that expires in December 2013 to support the issuance of letters of credit, to meet short-term funding requirements and to provide alternate liquidity for its similarly-sized commercial paper program. Terms of the syndicated revolving credit facility include a representation that no material adverse change has occurred, which was required only on the facility's effective date. The sole financial covenant is a 70% limitation on the ratio of funded debt to capitalization. The company has substantial flexibility under the capital structure covenant.

WEC had approximately $216 million of commercial paper outstanding at September 30, 2011. The commercial paper balance reflects, in part, the use of short-term debt to fund WEC's April 2011 $450 million debt maturity that was repaid in full. We expect WEC's short-term debt balance to gradually decline. WEC's most near-term debt maturity is $200 million due 2033.

WEPCO and Wisconsin Gas are borrowers under separate $500 million and $300 million revolving credit facilities, respectively, due December 2013.

Rating Outlook

The stable rating outlook considers the strong cash flow generated by WEPCO and Wisconsin Gas, the supportive regulatory environments within the jurisdictions in which they operate, and the company's conservative business and financial strategy amid a significant capital-expenditure program.

What Could Change the Rating - Up

In light of WEC's still sizeable construction programs, limited prospects exist for the rating to be upgraded over the next several years. Longer-term, core financial metrics would need to improve considerably, such as CFO pre-W/C to debt of 25% or more, for Moody's to consider an upgrade.

What Could Change the Rating - Down

The rating of WEC could be downgraded if the company elects to finance its construction programs more aggressively with greater leverage than is expected. Other events that could have negative rating implications include a significant increase in construction costs, the introduction or acquisition of non-regulated businesses, a less supportive regulatory environment or a decline in financial metrics such as a ratio of CFO pre-W/C to debt falling below 18% for an extended period.

Rating Factors

Wisconsin Energy Corporation

Regulated Electric and Gas Utilities Industry [1][2]	**Current 12/31/2010**		**Moody's 12-18 month Forward View* As of December 2011**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		A		A
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (10%)		Baa		Baa
b) Generation and Fuel Diversity (0%)		Baa		Baa
Factor 4: Financial Strength, Liquidity And Key Financial Metrics				

(40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	5.1x	A	4-4.4x	Baa
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	20.8%	Baa	20-23%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	17.4%	A	13-15%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	27.1%	Baa	42-50%	Baa
Rating:				
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		A3		A3

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2010; Source: Moody's Financial Metrics

Global Credit Research
Credit Opinion
6 DEC 2011

Credit Opinion: Xcel Energy Inc.

Xcel Energy Inc.

Minneapolis, Minnesota, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa1
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Jr Subordinate	Baa2
Commercial Paper	P-2
Public Service Company of Colorado	
Outlook	Stable
Issuer Rating	Baa1
First Mortgage Bonds	A2
Senior Secured MTN	(P)A2
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured Shelf	(P)Baa1
Commercial Paper	P-2
Northern States Power Company (Minnesota)	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
Sr Unsec Bank Credit Facility	A3
Senior Unsecured Shelf	(P)A3
Commercial Paper	P-2

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Key Indicators

[1]
Xcel Energy Inc.

	3Q11 LTM	2010	2009	2008
Adj CFO (pre w/c) + Interest / Interest	**5.0x**	**4.7x**	**4.2x**	**4.0x**
Adj CFO (pre w/c) / Debt	**22.1%**	**20.5%**	**19.9%**	**18.5%**
Adj CFO (pre w/c) - Dividends / Debt	**17.7%**	**16.2%**	**15.3%**	**14.3%**
Debt / Capitalization	**45.9%**	**47.0%**	**46.9%**	**48.2%**

[1] All ratios are calculated using Moody's Standard Adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Mostly supportive regulatory environment

Diverse energy supply portfolio

Significant capital expenditure program

Regulatory lag requiring ongoing rate case activity

CSAPR adds pressure to SPS

Stable financial metrics

Corporate Profile

Xcel Energy Inc. (Xcel: Baa1 senior unsecured, stable) is a holding company for four utility subsidiaries, Northern States Power (Minnesota) (NSP-Minnesota: A3 senior unsecured, stable), Northern States Power (Wisconsin) (NSP-Wisconsin: A3 senior unsecured, stable), Public Service Company of Colorado (PSCo: Baa1 senior unsecured, stable), and Southwestern Public Service Company (SPS: Baa1 senior unsecured, negative) that provide electricity and natural gas in eight states, predominantly Colorado, Minnesota, Texas and Wisconsin along with smaller operations in Michigan, New Mexico, and North and South Dakota. All of Xcel's utility subsidiaries operate as fully integrated entities with little deregulation occurring in their service territories. Xcel has approximately 5.3 million electric and natural gas customers.

SUMMARY RATING RATIONALE

Xcel's Baa1 rating for its senior unsecured obligations reflects the relatively stable cash flow provided by its geographically diverse regulated utility subsidiaries, the primarily supportive nature of its regulatory relationships, its diverse energy supply portfolio, the challenge of the significant capital expenditure programs occurring at the operating utilities and the strength of its financial metrics.

DETAILED RATING CONSIDERATIONS

MOSTLY SUPPORTIVE REGULATORY ENVIRONMENT

Xcel's Baa1 senior unsecured rating reflects the relatively supportive regulatory relationships within which its utility subsidiaries operate. Minnesota and Wisconsin's regulatory relationships are considered to be above average among U.S. state regulated utilities, evidenced by predictability and high expectation of timely recovery of costs and investments. Moody's considers the regulatory relationships that PSCo and SPS have with their respective regulators to be about average, with well-developed regulatory frameworks, despite some evidence of lower predictability or expectation of timely recovery of costs and investments. Xcel has generally received constructive regulatory treatment in Colorado for its general rate cases and benefits from numerous alternate rate mechanisms designed to assure a more timely recovery of various expenditures outside of a general rate case.

In New Mexico and Texas, Xcel's SPS subsidiary, which has historically contributed approximately 10% of consolidated funds from operations, remains more exposed to regulatory lag than Xcel's Midwestern utilities or PSCo. The company recovers its capital investments in Texas and New Mexico through general rate cases rather than via riders or other such mechanisms that could make recovery of these investments more timely and certain. Rate filings in Texas are based on a historical test year, which exacerbates regulatory lag when a utility is growing as SPS is. Furthermore, rate filings in New Mexico have a tendency to be protracted, delaying recovery and perpetuating regulatory lag.

DIVERSE ENERGY SUPPLY PORTFOLIO WITH OPERATIONS IN EIGHT STATES

Xcel benefits from a diverse energy supply portfolio that includes a significant amount of renewable resources. Power supplied in 2010 came approximately 51% from coal-fired resources, 12% from nuclear generation, 23% from gas, and 14% from renewables (including wind, hydro, solar, biomass, RDF, and landfill). Xcel's planned generation include up-rates at its nuclear facilities and increased renewables, mostly wind and solar. In addition, in conjunction with Colorado's new Clean Air Clean Jobs Act (CACJA) Xcel plans to retire approximately 900 MW of coal-fired generation, repowering another approximately 463 MW of coal-fired generation with natural gas, and building approximately 569 MW of natural gas, reducing NOx, SO2 and mercury exposure while also reducing carbon output. The company has reduced its emissions exposure at PSCo by installing environmental controls, and at the NSP utilities through environmental capital expenditures and repowering coal plants to natural gas. As a result, these subsidiaries are well positioned to comply with environmental regulations. SPS has the greatest exposure to coal and faces challenges in compliance with the Cross State Air Pollution Rule (CSAPR).

SIGNIFICANT CAPITAL EXPENDITURE PROGRAM

Xcel's subsidiaries are in the midst of significant capital expenditure programs that are expected to continue for at least the next several years. Over the next five years between 2012 and 2016, capital expenditures are projected to average $2.7 billion per annum, compared to an average of $2.2 billion per annum over the past three years. The largest named projects in Xcel's five-year plan are almost $1 billion allocated for NSP's CapX 2020 transmission projects (groups of projects expected to be completed by 2020) and another $1 billion for PSCo's CACJA, which includes both environmental upgrades and new generation. On the generation side, the five-year plan also includes $600 million for nuclear uprates and environmental upgrades related to CSAPR of roughly $500 million.

Capital spending is expected to peak in 2013 and decline thereafter, but over the next five years, the capital program will entail incremental debt. In order to maintain its solid credit metrics, Xcel will need ongoing regulatory support as well as sufficient amounts of equity financing during this period, though it does not expect to issue equity in 2012.

REGULATORY LAG REQUIRING ONGOING RATE CASE ACTIVITY

Given the high level of capital spending, Xcel is expected to continue on a treadmill of rate cases. Despite an extensive menu of rate recovery mechanisms, the company is under-earning its allowed rates of return in many of its jurisdictions. It has been successful, however, in obtaining meaningful rate increases this year, with $52 million of rate increases granted so far, $103 million in settlements awaiting final order (half of which is related to the Minnesota electric case), and an additional $198 million on request (most of which is related to the Colorado electric case).

CSAPR ADDS PRESSURE TO SPS

Moody's changed SPS's rating outlook to negative in August 2011 in light of the significantly higher capital spending anticipated for the next few years and the risk that its persistent regulatory lag would continue or become worse under CSAPR. The inclusion of Texas in CSAPR was a surprise and would require accelerated spending, and even then, SPS does not expect having adequate emission controls in place by the January 2012 compliance deadline. Capital spending estimates at SPS for 2012-2014 have been raised to $1.6 billion, up from an estimate of $1.15 billion in Xcel's 2010 10-K. SPS has limited near-term options by which to comply, since the market for emissions allowance trading is undeveloped, and SPS's smaller gas units would be hard pressed to replace the power now provided by its coal base load plants. SPS estimates that relying more on gas-fired generation would result in $200 to $250 million of incremental fuel costs a year. These incremental fuel costs are expected to be recovered in Texas through the normal fuel factor filing process. In the meantime, SPS is pursuing legal challenges to the 2012 implementation of CSAPR.

CSAPR also applies to Xcel's operations in Minnesota and Wisconsin. However, the NSP companies have already been operating under aggressive state environmental standards, so CSAPR is expected to have little impact.

STABLE CREDIT METRICS

Xcel's credit metrics, calculated in accordance with Moody's standard analytical adjustments, are well positioned for a utility holding company rated Baa1, and are projected to remain so in the foreseeable future. CFO pre-w/c + Interest/Interest was 4.7x for LTM 9/11, compared to 5.0x in 2010 and CFO pre-w/c to Debt was 20.5% and 22.1% in the same periods. Xcel's consolidated credit metrics demonstrate the stability that comes from being substantially all rate regulated. This stability is reflected in the even performance of NSP-Minnesota and PSCo, respectively Xcel's two largest subsidiaries.

The NSP companies' ratios are distinctly stronger than those of PSCo and SPS and thus merit a higher A3 rating than the Baa1 ratings for PSCo and SPS. However, SPS's ratios are weaker than those of PSCo and thus we have a negative outlook on SPS. The metrics for all of the utilities have seen uplift from bonus depreciation in 2011.

For NSP-Minnesota, CFO pre-w/c + Interest/Interest was 5.8x for LTM 9/11, compared to 5.4x in 2010 and CFO pre-w/c to Debt was 29.9% and 26.6% in the same periods. NSP-Wisconsin had CFO pre-w/c +Interest/Interest of 7.7x in LTM 9/11 and 6.1x in 2011, and CFO pre-w/c to Debt of 41.1% and 29.0% in the same periods. PSCo experienced CFO pre-w/c +Interest/Interest of 6.1x in LTM 9/11 and 5.5x in 2010 and had a ratio of CFO pre-w/c to Debt of 27.7% and 22.3% in the same periods. Finally, for SPS, CFO pre-w/c + Interest/Interest was 4.9x for LTM 9/11, compared to 3.8x in 2010 and CFO pre-w/c to Debt was 25.2% and 18.4% in the same periods.

NSP-Wisconsin ratios have recently mapped to levels that are higher than its actual rating according to Moody's methodology grid, but this improvement is due to a temporary boost from bonus depreciation and after its expiration, we expect those ratios to subside to pre-2009 levels. On the other hand, SPS's credit metrics map to a lower rating according to the grid, excluding the impact of bonus depreciation.

Liquidity Profile

With the renewal of the company's credit facilities in March 2011, Moody's expects Xcel to have adequate liquidity in the foreseeable near future. The company has $2.45 billion of committed capacity under credit facilities due in 2015: $800 million at the parent, $500 million at NSP-Minnesota, $150 million at NSP-Wisconsin, $700 million at PSCo, and $300 million at SPS. These facilities could be used to back up commercial paper that these entities may issue. At November 21, 2011, the Xcel parent company had $1 million in cash on hand and $582 million of availability under its credit facility. Overall, the consolidated company had $195 million in cash and $2.2 billion of availability under its credit facilities. The credit facility contains one financial covenant, requiring the debt to total capitalization ratio be below 65%.

The company will need to refinance material amounts of debt in the coming five quarters: $450 million of notes due on August 28, 2012 at NSP-Minnesota and $600 million of notes due on October 1, 2012 and $250 million due on March 1, 2013 at PSCo.

As a holding company, Xcel's primary source of cash is the dividends it receives from its subsidiaries (in the $600 million range per annum) . Although Xcel's subsidiaries are engaged in significant capital expenditure programs, liquidity at the parent level appears sufficient, given the amount of anticipated dividends (approximately $490 million currently), the large size of its credit facility, and limited parent level short-term funding needs. In 2012, the company does not expect to issue any equity beyond its dividend reinvestment program.

Rating Outlook

Xcel's stable outlook reflects the relatively low risk profile of its basic utility businesses and the relatively supportive regulatory environments in which those subsidiaries operate. The overwhelming majority of the company's revenues, earnings, and cash flows are provided by the four vertically integrated utility subsidiaries, so cash flows are expected to be reasonably predictable. The outlook also assumes that future capital expenditures will continue to be funded in a manner that is supportive of the company's current credit profile.

What Could Change the Rating - Up

The ratings or outlook could be revised upward if there were to be a continued improvement in financial performance; as demonstrated, for example, by a ratio of CFO pre-W/C to debt moving above 22% on a sustainable basis. Since regulated utility activities represent an overwhelming majority of Xcel's operations, this scenario would be unlikely without more supportive regulatory outcomes for several of its subsidiaries.

What Could Change the Rating - Down

The ratings or outlook could be revised downward if there were to be a sustained deterioration of financial performance; as demonstrated, for example, by a ratio of CFO pre-W/C to debt falling below the high teens for an extended period. Factors that could contribute to this deterioration include adverse regulatory rulings, significant operating difficulties, capital spending that is significantly higher than anticipated, or a change in business strategy which would increase the company's business risk profile.

Rating Factors

Xcel Energy Inc.

Regulated Electric and Gas Utilities [1]	**LTM Sep-30-2011**		**Moody's 12-18 month Forward View As of December 6, 2011***	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory framework		Baa		Baa
Factor 2: Ability to Recover Cost and Earn Returns (25%)				
a) Ability to recover Cost and Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position		A		A
b) Generation and Fuel Diversity		A		A
Factor 4: Financial Strength, Liquidity, & Metrics (40%)				
a) Liquidity		Baa		Baa
b) CFO (pre w/c) + Interest / Interest	5.0x	A	4.0x-5.0x	A
c) CFO (pre w/c) / Debt	22.1%	A	19%-22%	Baa
d) CFO (pre w/c) - Dividends / Debt	17.7%	A	15%-18%	Baa
e) Debt / Capitalization	45.9%	Baa	45%-49%	Baa
Rating:				
Indicated Rating from Grid		A3		Baa1
Actual Rating Assigned		Baa1		Baa1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments.

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Global Credit Research
Credit Opinion
8 DEC 2011

Credit Opinion: Enbridge Inc.

Enbridge Inc.

Calgary, Alberta, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
Subordinate Shelf	(P)Baa2
Pref. Stock -Dom Curr	Baa3
Enbridge Energy Partners, L.P.	
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Commercial Paper	P-2
Enbridge Income Fund	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa2
Enbridge Energy Limited Partnership	
Outlook	Stable
Senior Unsecured	Baa1
Subordinate Shelf	(P)Baa2

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Key Indicators

[1]
Enbridge Inc.

	[2]LTM	2010	2009	2008	2007	2006
FFO + Interest / Interest	**4.2x**	**3.7x**	**3.4x**	**3.3x**	**3.1x**	**3.0x**
FFO / Debt	**16.0%**	**13.4%**	**11.9%**	**10.9%**	**12.2%**	**11.4%**
Debt / Capitalization	**58.4%**	**59.4%**	**59.0%**	**61.1%**	**61.2%**	**62.1%**
Operating Margin	**8.8%**	**9.9%**	**10.1%**	**8.3%**	**9.6%**	**10.7%**

[1] All ratios are calculated in accordance with Moody's Natural Gas Pipelines Methodology. In addition, Moody's adjusts for one-time items. [2] Based on financial data as of 09/30/2011.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Favourable long-term fundamentals support liquids pipelines

Business risk low but rising

Weak financial metrics

Organizational and financial complexity and structural subordination

Corporate Profile

Enbridge Inc. (ENB, Baa1 senior unsecured) is a North American pipeline and gas distribution utility holding company. ENB generates stable cash flows and has a low business risk profile due to its focus on energy businesses that are either regulated or supported by long-term contracts.

ENB's liquids pipelines segment (51% of 2010 net income as adjusted by ENB for non-recurring items (ENB-adjusted net income)) is anchored by the regulated Enbridge System, the Canadian portion of the mainline system that moves the bulk of the crude oil produced in Western Canada to the U.S. and Eastern Canada. Both the Enbridge System and ENB's regional oil sands pipelines have grown significantly in the last five years driven by expansion of oil sands production. We believe that strong supply/demand fundamentals will exist in ENB's liquids pipelines segment for the foreseeable future.

ENB's Gas Distribution segment (16% of ENB-adjusted net income) holds Enbridge Gas Distribution (EGD), Canada's largest regulated gas distribution utility. The Gas Pipelines, Processing and Energy Services segment (12% of adjusted income) is home to some of ENB's higher business risk operations such as Tidal Energy Marketing (ENB's trading and marketing operation), Enbridge Gas Services (manages ENB's merchant capacity on its gas pipelines) and ENB's investment in the Aux Sable gas processing facility. These higher risk businesses comprise a small component of ENB's overall operations (about 6% of adjusted income). This segment also holds ENB's interest in gas pipelines including Alliance US, Vector Pipeline and Enbridge Offshore Pipelines located in the Gulf of Mexico.

ENB's sponsored investment reporting segment (21% of ENB-adjusted net income) consists of ENB's partial ownership interests in Enbridge Energy Partners, L.P. (EEP, Baa2 senior unsecured) and Enbridge Income Fund (ENF, Baa2 senior unsecured) both of which are financing vehicles for liquids pipeline, gas pipeline, gas gathering and processing (G&P), and a portion of its renewable power assets. Under Canadian GAAP, ENB equity accounts for its 26% investment in EEP which understates the relative size and importance of EEP to ENB. EEP's principal asset is the regulated Lakehead System, the U.S. portion of ENB's liquids mainline. EEP also has meaningful G&P investments. ENB has a 69% economic interest in ENF whose three segments are its 50% share of the Canadian portion of the Alliance gas pipeline system, the Saskatchewan liquids pipeline system, and renewable power projects.

SUMMARY RATING RATIONALE

ENB's Baa1 senior unsecured rating is primarily driven by the preponderance of low-risk, rate-regulated pipeline and gas distribution assets which generate a predictable and growing cash flow stream. However, these attributes are offset by a relatively weak financial profile for ENB's rating. Over the last five years, ENB was in midst of the largest construction program in its history. Property plant & equipment have almost doubled due primarily to the growth of the liquids pipelines segment which is being driven by rising oil sands production. 2011 is significant in that it is the first year that major projects like the Alberta Clipper and Southern Lights, which together cost roughly $6 billion, will be in service for the whole year.

Capital spending is unlikely to abate in the next four years, as ENB undertakes a second wave of pipeline projects to serve not only the oil sands but also oil shale from the Bakken. With the exception of the proposed $5.5 billion Northern Gateway project, investments on the horizon are smaller than the marquee projects of the last few years and thus pose less execution risk and can be better absorbed by the company's now much larger asset base. This pace of investment, however, will keep ENB's cash flow credit metrics from materially improving, because of the continuing lag between the investment of capital and commencement of cash flow.

ENB's business risk is on the rise and will need to be offset by a strengthening of ENB's financial profile to avoid negative rating pressure. For example, its Canadian liquids line adopted tariffs this year that introduced sensitivity to throughput volumes. TransCanada's Keystone pipeline has brought new competition to ENB's liquids system. Management is also interested in expanding new business lines, such as renewable energy, G&P, and international, which are relatively minor now but riskier than ENB's core businesses.

The rating also reflects ENB's organizational and financial complexity and the structural subordination of ENB's senior unsecured debt due to the use of master limited partnership and income fund vehicles and non-recourse debt. Furthermore, we consider the MLP and income fund structures to be inherently riskier than corporate structures given the twin imperatives of distribution growth and distributing all cash flow in excess of sustaining capital which reduces financial flexibility and renders these vehicles more vulnerable to interruptions in capital market access.

DETAILED RATING CONSIDERATIONS

The primary rating methodology applied to ENB is our Natural Gas Pipelines methodology. Notwithstanding that the majority of ENB's pipelines are liquids rather than gas, we believe that the rating factors in the Natural Gas Pipeline methodology are equally applicable to ENB's regulated and/or contracted liquids pipelines. In addition, we also consider the Regulated Electric and Gas Utilities methodology recognizing that ENB's regulated gas distribution utility investments. EGD is ENB's largest gas distribution utility and accounts for about three quarters of the ENB-adjusted net income from gas distribution utilities.

FAVOURABLE LONG-TERM FUNDAMENTALS SUPPORT LIQUIDS PIPELINES

ENB's significant growth in recent years has been driven in large part by the growth of Alberta's oil sands and U.S. demand for secure supplies of energy. Despite widespread concerns about the environmental impacts of oil sands production, we believe that there will continue to be strong demand for oil sands production and therefore pipeline capacity through the long-term. Accordingly, we expect that the long-term fundamentals for ENB's largest business segment will be favourable for an extended period.

BUSINESS RISK LOW BUT RISING

We consider ENB's predominant pipeline and gas distribution utility operations, which together comprise the majority of its assets, to have low business risk because they are either regulated or supported by long-term contracts and have attractive long-term fundamentals. The pipeline assets tend to be regulated or supported by long-term take-or-pay contracts with creditworthy counterparties (regional oil sands pipelines, Alliance and Vector) which lends stability and predictability to the pipeline cash flows.

On July 1, 2011, the Competitive Tolling Settlement (CTS) came into effect for the Enbridge System. This new tolling scheme introduces potential revenue volatility to the System. Previously, the Canadian liquids pipelines operated under cost-of-service ratemaking, which provided throughput protection whereby revenue under-collections or over-collections due to fluctuations in throughput volumes were rolled forward for recovery or refund in the following year. Under CTS, revenues will depend on volumes and other variables.

EGD's business risk remains low given its utility monopoly status and lack of commodity price exposure. EGD covers a sizable franchise territory in Toronto which has proved resilient through the economic cycle, and it continues to add new customers at a steady pace. The company is operating under a five-year incentive regulation (IR) settlement which expires at the end of 2012. We expect that the rate methodology for the next five year term will be credit-neutral and consistent with Ontario Energy Board's well-established framework.

ENB engages in several business activities that we consider to be riskier than its pipeline and gas distribution activities. The largest of these is the gas G&P business at EEP which is exposed to varying degrees of commodity price and volume risk. While ENB hedges EEP's price and volume exposures to a significant degree, a portion of the business must always remain unhedged to allow for volume fluctuations which depend on many factors (drilling activity, decline rates, commodity prices etc.) that EEP cannot control. Furthermore, it is only economic to hedge a few years into the future therefore this business is unavoidably exposed to price risk as hedges expire. Additionally, ENB's gathering facilities in the Gulf of Mexico (Enbridge Offshore), Aux Sable and Energy Services activities are exposed to commodity price and volume risks.

Renewable energy activities, principally wind and solar electricity generation, are riskier than the pipeline and gas distribution businesses although less risky than gas G&P. While this is a small component of the company now, ENB plans to grow renewable energy into another business segment. Renewables tend to be uneconomic in the absence of government subsidies and therefore require legislative or regulatory support in order to be built. Furthermore, individual renewable projects are arguably dispensible unlike say ENB's mainline system without which the functioning of the North American economy would likely be significantly constrained.

WEAK FINANCIAL METRICS

ENB has a weak, though stable financial profile. ENB's weak financial profile is mitigated by the strategic importance of the mainline system which moves the majority of WCSB crude production to the U.S. and eastern Canada. To support ENB's ratings, the financial profile needs to be stronger going forward, as cash flow becomes more variable with the introduction of volume risk with CTS, introduction of competition from TransCanada's Keystone projects, and new investments in unregulated businesses.

Cash flow has increased from new projects that have come into service, but debt has also risen in tandem so that cash flow metrics have not improved significantly. The lag in cash flow from new investments will continue to weigh on ENB's credit metrics as the company keeps up its capital expenditures. Future improvement in credit metrics is deterred by the company's plan to rely on debt, rather than equity, for external financing of the next wave of projects. Consequently, ENB's funds flow from operations (FFO)/Debt is expected to be sustainable in the 11% to 13% range and FFO Interest Cover in the mid-3x range.

ORGANIZATIONAL AND FINANCIAL COMPLEXITY AND STRUCTURAL SUBORDINATION

ENB's use of MLP/Income Fund vehicles to control key infrastructure assets and its use of non-recourse debt creates a degree of complexity in ENB's organization and financing structure. We consider this to be a relative weakness in that it obscures economic reality and creates structural subordination. The roughly $4 billion of long-term debt at the ENB level as of September 30, 2011 is structurally subordinate to approximately $14 billion of long-term debt at the subsidiary/sponsored investment level including EGD, Enbridge Pipelines, ENF and Alliance Pipeline as well as EEP.

Notwithstanding that EEP is critical to ENB by virtue of its ownership of the Lakehead System and that EEP has no employees and is operated by ENB, ENB has not been required to consolidate EEP under Canadian GAAP. We believe that equity accounting for EEP significantly understates the degree of interrelatedness between ENB and EEP and EEP's importance to ENB. Beginning in January 2012, ENB will adopt US GAAP and consolidate EEP. Based on September 2011 balance sheet, EEP would increase ENB's consolidated debt by roughly $4 billion from debt reported under Canadian GAAP.

We also note that, all else being equal, the execution and financing risks are higher for an MLP than a corporation because of the MLP's high payout ratio and consequent higher reliance on access to the capital markets for both equity and debt funding. This has been the case for EEP in recent years and has resulted in ENB providing significant financial support to EEP in the form of periodic equity injections, inter-corporate credit facilities and arrangements to fund portions of capital projects (Alberta Clipper).

Liquidity Profile

We believe that ENB's committed liquidity is adequate.

ENB generated FFO of about $2.5 billion during the last four quarters ending September 30, 2011. Combined with cash on the balance sheet at September 30, 2011 of $0.6 billion, ENB will have cash resources of roughly $3 billion. After dividends of approximately $0.9 billion, capital expenditures of about $4 billion and scheduled debt maturities of about $0.3 billion, we estimate that ENB will have a funding requirement of roughly $2 billion for the four quarters ending December 31, 2012.

As of September 30, 2011, ENB had approximately $6.5 billion of authorized credit under various committed revolving credit facilities both at the holding company level and at subsidiaries. This figure excludes the credit facilities at EEP since ENB does not consolidate EEP. We calculate that availability under these facilities was roughly $3.8 billion at September 30, 2011, an amount sufficiently in excess of ENB's estimated funding requirement for the four quarters ending December 31, 2012.

Rating Outlook

The rating outlook is stable reflecting our expectation that ENB's business risk profile will remain relatively low, and that ENB's funds flow from operations (FFO)/Debt is sustained in the 11% to 13% range and FFO Interest Cover, in the mid 3x range.

What Could Change the Rating - Up

ENB's rating would likely be upgraded if the company could demonstrate that there is likely to be a improvement in key cash flow metrics such as FFO/Debt above 15% and FFO Interest Coverage above 3.8x on a sustainable basis.

What Could Change the Rating - Down

ENB would likely be downgraded if there were a deterioration in both its business risk profile and its cash flow credit metrics. For instance, a material increase in exposure to the riskier G&P segment or FFO/Debt sustained below 10% and FFO Interest Coverage, in the low 3x range would likely result in a downgrade.

Rating Factors

Enbridge Inc.

Natural Gas Pipelines [1]	[2]**Current LTM**		[3]**Moody's 12-18 Month Forward View As of 11/18/2011**	
Factor 1: Market Position (20.0%)	**Measure**	**Score**	**Measure**	**Score**
a) Market Position		Aa		Aa
Factor 2: Quality of Supply Sources (20.0%)				
a) Quality of Supply Sources		Aa		Aa
Factor 3: Contract Quality (20.0%)				
a) Contract Quality		Baa		Baa
Factor 4: Financial Strength (40.0%)				
a) (FFO + Interest Expense) / Interest Expense (3 Year Avg)	4.2x	A	3.0-4.0x	Baa
b) FFO / Debt (3 Year Avg)	16.00%	Baa	11.5-13%	Ba
c) Debt / Book Capitalization (3 Year Avg)	58.40%	Ba	58-63%	Ba
d) Operating Margin (3 Year Avg)	8.80%	B	8-12%	B
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are calculated in accordance with Moody's Natural Gas Pipelines Methodology. In addition, Moody's adjusts for one-time items. [2] Based on financial data as of 09/30/2011. [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures

Global Credit Research
Credit Opinion
11 MAY 2012

Credit Opinion: TransCanada PipeLines Limited

TransCanada PipeLines Limited

Calgary, Alberta, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A3
Senior Unsecured	A3
Jr Subordinate	Baa1
Pref. Stock -Dom Curr	Baa2
Parent: TransCanada Corporation	
Outlook	Stable
Issuer Rating	Baa1
NOVA Gas Transmission Ltd.	
Outlook	Stable
Senior Unsecured	A3
ANR Pipeline Company	
Outlook	Stable
Senior Unsecured	A3
Gas Transmission Northwest LLC	
Outlook	Stable
Senior Unsecured	A3
TC Pipelines, L.P.	
Outlook	Stable
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3

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Key Indicators

[1]
TransCanada PipeLines Limited

	[2]LTM	2011	2010	2009	2008	2007
FFO + Interest / Interest	3.3x	3.3x	3.0x	3.0x	3.4x	3.3x
FFO / Debt	15.3%	14.5%	12.6%	13.6%	14.0%	16.2%
Debt / Capitalization	49.8%	50.6%	53.7%	54.0%	58.5%	57.3%
Operating Margin	35.2%	35.5%	32.2%	34.1%	33.5%	30.3%

[1] All ratios are calculated in accordance with Moody's Natural Gas Pipelines Methodology. In addition, Moody's adjusts for one-time items. [2] Last twelve months, based on financial data as of 03/31/2012.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Influential scale of business with geographic and market diversification

Relatively low-risk pipeline and electricity generation company with stable cash flows

Supportive regulatory and business environments in Canada

Financial metrics weakened by the magnitude of capital investment

Strong liquidity despite the propensity to aggressively manage liquidity

Event risk attributable to the confluence of multiple events across business segments/projects

Corporate Profile

TransCanada PipeLines Limited (TCPL) is a diversified energy company 100% owned by TransCanada Corporation (TCC), a publicly traded company holding only the TCPL asset.

TCPL is organized into three business segments: Natural Gas Pipelines, Oil Pipelines and Energy - with attributed EBITDA (12 mths ending 31/12/11) approximately 61%, 11% and 28%, respectively.

The Natural Gas Pipelines segment comprises one of North America's largest networks of integrated gas pipelines and regulated gas storage.

The Oil Pipelines segment consists of the Keystone pipeline that went into service in 2010 and was expanded in the first quarter of 2011, carrying crude produced in Alberta's oil sands to markets in Illinois and Oklahoma. TCPL's pipelines are virtually all regulated - in Canada by the National Energy Board (NEB); in the United States by the Federal Energy Regulatory Commission (FERC).

The Energy segment comprises a diversified portfolio of unregulated electricity generation and gas storage assets in Canada and the United States. TCPL's generation assets tend to be either low cost (e.g. Bruce nuclear, TC Hydro, and the Alberta PPAs (Shearness and Sundance A and B coal plants)) or supported by long-term contracts with highly rated counterparties (e.g. Bruce Power, Portlands Energy Centre, Cartier Wind, Becancour, Grandview, Coolidge and Halton Hills).

At 31/12/11, approximately $15 billion of TCPL's $18.6 billion of consolidated long term debt resided at TCPL. The balance resided at subsidiaries: including NOVA Gas Transmission Ltd. (NOVA), Gas Transmission Northwest Corporation (GTN) and ANR Pipeline Company (ANR); and investees: including TC Pipelines, LP, Great Lakes Gas Transmission, Iroquois Gas Transmission System, L.P. and Portland Natural Gas Transmission System.

SUMMARY RATING RATIONALE

TCPL's A3 senior unsecured rating reflects its low business risk profile offset by its relatively weaker financial profile. TCPL's low business risk is attributable to the stable and predictable cash flows generated by its extensive and diversified portfolio of regulated natural gas pipelines, contracted oil pipelines and relatively low-risk electricity generation assets; its strategic importance as the entity transporting the majority of gas produced in the Western Canada Sedimentary Basin (WCSB); and the supportive regulatory and business environments in which its Canadian assets operate. TCPL's financial profile has weakened over the last few years due to the substantial capital investment that it is making across all three business segments. The $13 billion program (oil pipelines $7.8 billion; natural gas pipelines $2.2 billion; energy $3 billion) has approximately $7 billion still to be spent over the next three years. It is expected to begin contributing to higher EBITDA towards the end of 2012 when the Bruce Power 1 & 2 reactors are scheduled to be back in service, and gain momentum in 2013 and 2014 as the other elements, most notably the pipeline projects, are brought into service. It is noteworthy that the protracted approval process for the Keystone XL pipeline, the largest investment at approximately $7.5 billion, has had the unintended benefit of improving financials and increasing the internally generated funding component for the investment.

TCC's Baa1 issuer rating is one notch lower than TCPL's A3 senior unsecured rating reflecting the structural subordination of TCC's obligations to the debt of TCPL and its subsidiaries.

DETAILED RATING CONSIDERATIONS

The primary rating methodology applied to TCPL is our Natural Gas Pipelines Methodology, since TCPL's pipeline investments account for approximately 70% of its consolidated assets and EBITDA. However, we also consider our Unregulated Utilities and Power Companies Methodology, recognizing that unregulated power represents a significant portion of TCPL's operations.

TCPL maps to an A3 under our Natural Gas Pipelines Methodology although this does not fully capture the higher business risk profile of TCPL's unregulated power investments (~28% of EBITDA (12 mths ended 31/12/11)). Under the Unregulated Utilities and Power Companies Methodology TCPL maps in the low Baa range reflecting a set of financial metrics that would be considered weak for a company solely engaged in unregulated power generation. An EBITDA-weighted average of the two grid-indicated ratings yields a rating indication of approximately Baa1 which falls within the one to two notch band around the assigned rating that our rating methodologies aim to achieve. We continue to place considerable emphasis on the strategic importance of TCPL's Canadian pipeline assets in moving the majority of WCSB gas production to market and the relatively supportive regulatory and business climates in Canada.

Over the past several months, TCPL's Keystone XL pipeline project has dominated the company's storyline and, to a degree, restricted TCPL's ability to respond to market developments impacting its oil pipeline business. The significance and magnitude of the Keystone XL project and the political sensitivity it has taken on in an election year, coupled with the investment to date, all but locked in TCPL to staying the course despite considerable uncertainty as to timing and whether or not XL will ultimately be approved. The outcome for TransCanada has been to see Enbridge and Kinder Morgan react and propose alternative pipeline projects - Enbridge's Seaway acquisition, reversal and expansion; Enbridge's Spearhead expansion; Kinder Morgan's Trans Mountain expansion, Enbridge's Line 9 reversal - and seize the initiative and the timeline to provide takeaway capacity and market reach for oil sands production.

With all the focus on XL, it is easy to lose perspective and overlook TCPL's business platform and strengths. In the first half of 2012, TCPL has responded: first with plans to proceed with the southern leg of XL from Cushing to the Gulf ("Keystone Gulf Coast Project") and with a re-filing of its application for the environmentally-sensitive, cross-border section routed through Nebraska. Our assessment is that TransCanada has now mitigated some of its downside exposure if Keystone XL is not approved, by developing a stand-alone pipeline that will relieve the bottleneck at Cushing. Initially, we expect that TransCanada will be exposed to some merchant risk with the Gulf Coast pipeline until the fate of Keystone XL is certain and longer term commitments signed - either with shippers moving oil from Cushing to Gulf refiners or as part of the Keystone/Keystone XL system. Either way, we consider the risk to be manageable for TransCanada.

In addition, TransCanada has used the release of first quarter results, and its annual general meeting, to reintroduce perspective by emphasizing its overall development plans that include, but are not defined by Keystone XL. Specifically, TransCanada noted that it expects to complete $13 billion of projects currently in development - $7.8 billion/oil pipelines; $2.2 billion/natural gas pipelines; $3 billion/energy - over the next 3 years, that include:

Oil pipelines

- Keystone Gulf Coast

- Keystone XL

- Keystone Bakken Marketlink

- Keystone Hardisty Terminal Project

Natural gas pipelines

- Alberta System expansion and additions

- Tamazunchale pipeline extension in Mexico

Energy

- Bruce Power reactors 1 & 2 restarts

- Cartier wind power in Quebec

- Acquisition of Ontario solar projects

Of the $13 billion, about $7 billion remains to be invested. We expect that it will be comfortably financed from internally generated cash flow and debt capacity.

TCPL benefits from a large and growing asset base with consolidated assets of approximately $49 billion at December 31, 2011. We consider the Canadian pipeline assets to have the lowest business risk of all of the assets in TCPL's portfolio. Due to higher levels of competition and lack of throughput protection afforded to most U.S. pipelines, we consider the U.S. pipelines to have somewhat higher business risk than the Canadian pipelines but clearly lower business risk than the unregulated power assets.

TCPL's Canadian pipeline assets, including the Alberta System and Canadian Mainline, are strategically important to both Canada and the U.S. in that they transport a significant portion of WCSB gas production to markets throughout North America. TCPL's extensive network of pipelines and large number of interconnections with other pipelines allows it to offer shippers access to a variety of downstream markets.

Despite lower throughput on the Mainline in recent years, which has placed upward pressure on tolls and adversely impacted the Mainline's competitiveness, we continue to believe that TCPL's Canadian-based assets benefit from the supportiveness of Canada's business and regulatory environments relative to other jurisdictions. For a number of reasons, we believe that the Mainline's challenges will be resolved without any material adverse impact on TCPL's financial condition. We note that today the Mainline represents a smaller proportion of TCPL's large and diversified asset portfolio than it did even five years ago. Also, the Mainline is an essential component of the North American gas transportation network for which there are no economic alternatives in the form of existing or potential new pipelines. Furthermore, the Mainline was developed over several decades on the premise of cost-of-service regulation incorporating throughput protection. We do not expect that fundamental changes to these regulatory principles would be undertaken lightly.

Although TCPL has a diverse portfolio of regulated pipelines, the majority of the gas transported is produced from the WCSB. In recent years, a number of factors have contributed to reduced gas production in the WCSB and declining throughput on the Alberta System and the Mainline. Declining throughput reflects a number of factors including lower drilling activity due to changes to Alberta's royalty regime; natural production declines in existing wells; increased intra-Alberta consumption driven by oil sands development; recession-reduced gas demand and gas prices as well as the rapid growth of shale gas production in the U.S.

TCPL is also attempting to mitigate the impact of declining WCSB volumes by connecting to new sources of supply with projects such as Groundbirch, Horn River and Bison and continuing to develop projects such as Alaska and Mackenzie which would connect potentially large new sources of gas to TCPL's pipelines.

TCPL's unregulated operations have become a larger proportion of its total assets in recent years due to activities like refurbishing Units 1 and 2 at the Bruce nuclear facility, acquiring the 2,480 MW Ravenswood gas/oil fired generating complex in New York City and constructing fully contracted power facilities such Halton Hills, Cartier Wind and Coolidge.

We consider TCPL's electricity generation assets to be relatively low risk because they tend to have low marginal costs of production, be supported by long-term contracts with highly rated counterparties or be located in attractive markets. TCPL typically depreciates its power generation assets over the life of the associated power purchase agreements. Given a target capital structure, this has the effect of ensuring that the assets are fully depreciated and that TCPL is carrying little or no debt against these assets at expiry of the PPAs. While TCPL's investment in the Bruce nuclear facilities provides it with a source of low-cost generation, there are material risks related to the restart and refurbishment of the Bruce A Units 1 & 2.

While most of the technically challenging nuclear-related aspects of the refurbishment have now been completed and they are proceeding towards synchronizing the power generation from Unit 2, there continue to be some, what we expect are manageable, issues causing delay in commissioning. It is expected that Unit 2 will be in service this quarter, but it appears likely that Unit 1 could face similar delays and not be brought into service until the third quarter. If that is the case, the PPA`s floor price for power produced across all four reactors would fall away on July 1, 2012 and Bruce Power would be exposed to spot market rates until all four units can be brought into service. The impact is expected to be minimal as the delays in getting Units 1 & 2 in service will be short-lived.

In addition, cash flows from the Ravenswood plant have been significantly below forecast due to the construction of new generation in NYISO and NYISO's application of pricing rules for new capacity. While TCPL and others have petitioned FERC regarding NYISO's application of the new capacity pricing rules, the outcome of the petition and its impact on Ravenswood's future cash flows is not yet known. On a positive note, approximately 800MW of capacity has been taken out of service and Ravenswood is seeing significantly better rates from the 2012 summer strip auction than it experienced last summer.

The dispute over TransAlta's decision to shut down Sundance units 1 & 2 and declare force majeure under the PPA owned by TransCanada, and the subsequently issued notice for destruction, should be resolved with the arbitration decision expected by mid-year. TransCanada's position is that economic destruction is not warranted and continues to book revenue and costs under the PPA. An adjustment to earnings would be required for TransCanada if TransAlta's case prevails. Offsetting would be a payment to TransCanada of the PPA's book value. A decision in favour of TransCanada's position would likely require that TransAlta compensate TransCanada until the Sundance units are back in service. The Sundance PPA runs until 2017.

We continue to believe that the business risk profile of the unregulated Energy segment is fundamentally higher than that of the regulated Pipelines segment and we anticipate that TCPL's Energy segment cash flows will be less stable and predictable than those of the Pipeline segments.

RELATIVELY WEAK FINANCIAL PROFILE

TCPL's financial profile reflects regulatory policy in Canada where regulators typically utilize a more leveraged capital structure and less robust returns on equity for ratemaking purposes than is typical for regulated U.S. pipelines. We continue to believe that TCPL's weak financial profile is balanced by the low-risk nature of its assets, the strategic value of its Canadian regulated pipelines and the supportive regulatory and business environments in Canada. However, to remain at the A3 rating level, we expect TCPL to demonstrate sustained improvement in its financial metrics, for instance, FFO Interest Coverage in the mid 3x range and FFO/Debt of about 15%.

CONSISTENT MANAGEMENT STRATEGY & RELATIVELY CONSERVATIVE APPROACH TO FUNDING ORGANIC GROWTH AND ACQUISITIONS

Our rating reflects TCPL's consistent focus on regulated pipeline and gas storage assets, relatively low-risk power generation assets and unregulated gas storage assets that complement its pipeline investments as well as management's demonstrated track record of issuing substantial amounts of up-front common equity in support of organic growth and acquisitions.

In the five years ended 2010, TCPL's asset base virtually doubled in size through a combination of acquisitions and organic growth. This growth was generally consistent with TCPL's core strategy (regulated pipelines and low-risk power generation) and the acquisitions tended to be of manageable size. However, this growth increased TCPL's exposure to unregulated businesses; fundamentally riskier assets such as Bruce nuclear, Ravenswood uncontracted generation, and unregulated gas storage; and operations outside of Canada. While TCPL manages the higher business and operating risks associated with its unregulated activities by underpinning these assets with contracts where possible, the increased size of the Energy segment and increased exposure to assets outside of Canada contributed to TCPL's one-notch downgrade in June 2008. We believe that further increases in the relative size or risk of TCPL's unregulated activities would result in downward rating pressure unless offset by a stronger financial profile.

TCPL is both an operating company (the Mainline assets reside at TCPL) and a holding company (NOVA, ANR and GTN among others are held at subsidiaries that issue third party debt). TCPL's debt is structurally subordinate to the debt at NOVA, ANR, GTN and other subsidiaries and investees. However, there are no significant ring-fencing restrictions between TCPL and its wholly-owned subsidiaries and cash is managed on a centralized basis. This, combined with the high degree of operational integration of TCPL's various pipeline systems, causes us to consider the credit profiles of TCPL and its subsidiaries to be more closely aligned than would be the case if strong ring fencing provisions were to exist.

We continue to believe that there is potential for increased organizational complexity and structural subordination due to the joint ownership of assets including TCPL's investment in Bruce Power and TC PipeLines, LP and potential future investments such as Alaska and the Mackenzie.

Liquidity Profile

Although TCPL at times seems aggressive in its management of liquidity with modest committed bank facilities in relation to its capital investment program and ongoing funding requirements, it is based on management's assumption that TCPL will continue to have ready access to funding through capital market transactions. The company's continuing success in that regard, most notably through the 2008/09 global financial crisis, is cited by management and provides a degree of comfort.

As of the date of this writing, liquidity is strong given recent developments - principally the delay in Keystone XL, the issuance of $750 million term debt in November 2011 and the issuance of US$500 million of three-year senior notes in March. At the end of March, TCPL was reporting cash on hand of about $200 million, after retiring about $500 million of $880 million of 2012 debt maturities, and $4.3 billion in committed and undrawn credit facilities along with its commercial paper programs.

TCPL is expecting to generate approximately $3.5 billion of funds from operations during the fiscal year ending 31 December, 2012 to cover expected dividends of approximately $1.4 billion and capital expenditures of approximately $3.3 billion, leaving an expected funding requirement of approximately $1.6 billion with excess liquidity of approximately $2.9 billion.

Rating Outlook

The Stable outlook reflects our expectation that TCPL will remain predominantly a regulated energy infrastructure company. The outlook also reflects our expectation TCPL will achieve FFO Interest Coverage in the mid 3x range and FFO/Debt of 15% or more in 2012.

What Could Change the Rating - Up

TCPL's rating could be upgraded if the company were to achieve a sustainable improvement in its financial metrics, for instance, FFO Interest Coverage greater than 4x and FFO to Debt in the high teens. This assumes a satisfactory resolution to the 2012/13 Mainline toll application and that TCPL's Energy segment either remains stable or declines in terms of its contribution to the overall enterprise. Since we consider the Energy segment to be riskier than the Natural Gas or Oil Pipeline segments, the upgrade thresholds for TCPL's financial ratios would increase if the relative size of the Energy segment were to grow.

What Could Change the Rating - Down

While we do not consider it probable, it is possible that a confluence of events could, in the aggregate, produce a negative outcome with a significant impact on operations - further delays, additional capex with the Bruce Power units 1/2 start-up; a material deterioration in the prospects for Natural Gas Pipelines due, for example, to further changes in North American gas flow as a result of shale gas developments; delays and/or negative outcomes to rate applications re: TCPL's Canadian Mainline and its Ravenswood generating station in New York; significant rerouting costs and timing of remaining capex for Keystone XL; global economic/financial uncertainty disrupting normal access to capital markets - that would affect our outlook and adversely impact the rating if FFO Interest Coverage dropped below 3x and FFO to Debt below 13%. We note that various actions (deferral of capex; suspension of dividends) would be available to management to mitigate the potential impact.

Given the higher risk of the Energy segment, a material increase in the relative size of that segment could also lead to a downgrade unless balanced by a strengthening of TCPL's financial metrics.

Rating Factors

TransCanada PipeLines Limited

Natural Gas Pipelines [1]	[2]Current LTM		[3]Moody's 12-18 Month Forward View As of 05/08/2012	
Factor 1: Market Position (20.0%)	**Measure**	**Score**	**Measure**	**Score**
a) Market Position		Aa		Aa
Factor 2: Quality of Supply Sources (20.0%)				
a) Quality of Supply Sources		A		A
Factor 3: Contract Quality (20.0%)				
a) Contract Quality		A		A
Factor 4: Financial Strength (40.0%)				
a) (FFO + Interest Expense) / Interest Expense (3 Year Avg)	3.2x	Baa	3.5x - 3.7x	Baa
b) FFO / Debt (3 Year Avg)	14.0%	Ba	15% - 17%	Baa
c) Debt / Book Capitalization (3 Year Avg)	52.2%	Baa	52% - 50%	Baa
d) Operating Margin (3 Year Avg)	34.0%	Ba	31% - 35%	Ba
Rating:				
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		A3		A3

[1] All ratios are calculated in accordance with Moody's Natural Gas Pipelines Methodology. In addition, Moody's adjusts for one-time items. [2] Based on financial data as of 03/31/2012. [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures

$1,500 to approximately $2,500,000. MCO and MIS also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually at www.moodys.com under the heading "Shareholder Relations - Corporate Governance - Director and Shareholder Affiliation Policy."

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STANDARD & POOR'S

Global Credit Portal
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January 3, 2012

AGL Resources Inc.

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Table Of Contents

AGL Resources Inc.

Major Rating Factors

Corporate Credit Rating
BBB+/Stable/A-2

Strengths:

- Highly stable regulated utility operations generate about 70% of consolidated operating profit.
- The utility operations have a large, geographically diverse residential and commercial customer base.
- We expect the more volatile nonregulated businesses will grow at a measured pace.

Weaknesses:

- AGL's wholesale trading and marketing business, Sequent, has inherently volatile cash flows and requires diligent risk management to ensure its derivative exposure is properly managed.
- Pro forma for Nicor, the company will expand to Illinois, a jurisdiction we consider more challenging, and acquire a volatile Caribbean-based shipping company.
- Significant financial leverage.

Rationale

Atlanta-based AGL Resources Inc.'s rating reflects an "excellent" business risk profile and a "significant" financial risk profile (as our criteria define the terms). With monopolistic regulated utility operations generating the majority of consolidated cash flow, the consolidated company should generate relatively consistent cash flow regardless of the economy and commodity price fluctuations. Rate regulation allows the utilities to pass through operating and capital costs to their customer base and earn a rate on equity in the 10% area on its investments, although cash flows and earnings can lag behind authorized returns between rate cases.

The new AGL is the largest stand-alone gas utility that we rate, with about 4.4 million customers. Its customer base is concentrated in Illinois (about 49% of AGL customers, all acquired from Nicor) and Georgia (34%), with smaller numbers in New Jersey, Virginia, Florida, Maryland, and Tennessee. We generally regard Illinois to be a challenging regulatory environment for utilities to manage. However, Nicor has historically enjoyed satisfactory regulatory relations due in large part to its competitive rates to customers and good operating efficiency statistics. The utility has an acceptable 10.2% authorized return on equity, favorable weather-normalization and cost-recovery mechanisms, and a bad debt tracker. We view regulation in Georgia more favorably. In Georgia, the company benefits from a straight-fixed-variable-rate design structure that minimizes revenue risk due to weather and conservation. Georgia is one of a few states where natural gas delivery is deregulated. As such, Atlanta Gas is only responsible for distributing natural gas, which lowers the utility's working capital requirements because independent marketers--including AGL's Southstar joint venture--buy and sell the natural gas to customers.

The new company's nonregulated businesses will contribute about 25% of overall EBITDA and exhibit higher cash-flow volatility. The businesses mainly consist of retail marketing via the Southstar joint venture, marine shipping via the Tropical Shipping subsidiary, wholesale trading and marketing of natural gas via the Sequent subsidiary, and merchant natural gas storage. In general, AGL's nonregulated operations are currently performing at or near trough levels due to low natural gas price volatility and general macroeconomic weakness. We would expect this trend to continue in 2012.

Of the nonregulated businesses, retail marketing is the steadiest cash flow generator. Despite low barriers to entry and thin profit margins, Southstar consistently generates EBIT in the $90 million to $100 million area, serving 30% to 35% of the Atlanta Gas Light service territory.

Tropical Shipping's financial performance is highly sensitive to economic conditions and, in our view, is vulnerable given the current market. The subsidiary tends to underperform when tourism declines in the Caribbean, its operating area.

Sequent's trading profits depend on natural gas price volatility, geographic basis differentials, and the shape of the natural gas futures curve. In recent years, the segment's EBIT has ranged from a high of $90 million in 2006 to a loss of $9 million for the nine months ended Sept. 30, 2011. We expect trough-like performance to continue through at least 2012, given currently stable low prices. Aside from cash flow risk, Sequent's operations require robust risk controls to monitor the effectiveness of its hedging strategies and liquidity risks. Sequent enters into numerous financial derivative contracts that offset physical positions.

Lastly, AGL operates two high deliverabilty natural gas storage caverns (Jefferson Island and Golden Triangle). Due to low natural gas price volatility and a glut of storage capacity, storage rates have fallen dramatically over the past two to three years and we expect them to remain low.

In our base case financial projections, we assume that the regulated utility EBIT grows modestly from current levels and that the company achieves some cost synergies by eliminating duplicate corporate overhead. In the nonregulated businesses, we assume further softening at Sequent and Tropical to be more reflective of second-half 2011 industry conditions. Under these assumptions, we would expect the company to generate funds from operations (FFO) of roughly $780 million to $800 million in 2012, increasing to slightly over $800 million in 2013. Key projected ratios in 2012 are FFO to debt of 18.5%, debt to EBITDA 3.6x, and debt to capital of 55%. We expect the company to generate modest discretionary cash flow in 2012, with FFO exceeding capital expenditures and common dividends.

Pro forma adjusted debt of about $4.5 billion consists of about $3 billion in long-term unsecured notes at AGL Capital Corp., $500 million of first mortgage bonds at Nicor Gas, and nearly $400 million of unsecured notes at two AGL utilities, Atlanta Gas Light and Pivotal Utility Holdings. We also include adjustments for operating leases, underfunded pension obligations, and asset retirement obligations as debt, but we reduce short-term working capital debt for the value of natural gas inventories AGL holds at the utilities.

Liquidity

AGL's liquidity is "adequate." During the past year, the company raised about $1 billion in long-term debt, effectively prefunding the pending Nicor merger.

Pro forma for the approximate $1 billion cash purchase price as of Sept. 30, 2011, we estimate that the company has about $1 billion in liquidity between cash on hand and its two credit facilities: AGL's $1.3 billion revolving credit facility due 2016 and Nicor's $700 million revolving credit facility due 2016. We expect the company to remain comfortably within financial covenants on both facilities.

We expect that the company will generate positive discretionary cash flow in 2012, with FFO in the $800 million area, modestly covering capital spending, common dividends, and minority interest distributions. When considering seasonal working capital needs AGL requires for winter season natural gas purchases, we calculate liquidity sources exceeding uses by 1.2x to 1.3x. We also note that much of the capital spending we anticipate is discretionary in nature; the company could scale back capital spending in a stressed environment.

In our analysis, we also consider the risk associated with the Illinois Commerce Commission's (ICC) review of Nicor Gas's performance-based rate plan for 1999-2002. Various intervening parties have submitted testimony to the ICC requesting refunds of up to $286 million. AGL would have sufficient liquidity to fund the full amount if it immediately became due, although we consider this scenario unlikely. If the ICC rules in favor of the intervening parties, we believe it more probable that AGL would pay out the refunds over a number of years.

Outlook

The outlook is stable. We could consider a downgrade if AGL's performance deteriorates materially below our expectations, whether due to poor merger integration or adverse regulatory decisions, such that we expect FFO to fall below 16% to 17%. We could consider an upgrade if FFO to debt sustainably improves to 22% to 23%, assuming the current mix of regulated and nonregulated activities. While we would not expect to see this improvement soon, the company could achieve these metrics over time with the realization of synergies and debt reduction through free cash flow.

Table 1

AGL Resources Inc.--Peer Comparison

Industry Sector: Gas

	AGL Resources Inc.	Atmos Energy Corp.	Vectren Corp.	New Jersey Natural Gas Co.	South Jersey Gas Co.	The Laclede Group Inc.
Rating as of Jan. 3, 2012	BBB+/Stable/A-2	BBB+/Stable/A-2	A-/Stable/--	A/Stable/A-1	BBB+/Stable/A-2	A/Stable/--
	--Average of past three fiscal years--					
(Mil. $)						
Revenues	2,496.7	5,660.0	2,234.4	1,035.4	509.5	1,946.4
EBITDA	658.0	711.3	511.6	146.3	114.5	153.9
Net income from cont. oper.	224.3	192.4	131.9	59.4	40.9	58.6
Funds from operations (FFO)	505.3	570.8	447.9	126.7	98.0	122.4
Capital expenditures	450.3	522.3	365.0	79.3	88.6	57.9
Free operating cash flow	24.3	143.5	65.2	45.0	3.8	53.2
Discretionary cash flow	(119.3)	22.5	(42.1)	0.1	(19.7)	19.5
Cash and short-term investments	22.0	96.6	38.5	25.8	2.1	58.8
Debt	2,537.7	2,489.3	1,976.2	470.7	444.4	551.0
Equity	1,779.7	2,135.9	1,412.5	562.2	420.1	513.2
Adjusted ratios						
EBITDA margin (%)	26.4	12.6	22.9	14.1	22.5	7.9
EBITDA interest coverage (x)	5.4	4.1	4.8	6.8	5.8	4.8

Table 1

AGL Resources Inc.--Peer Comparison (cont.)						
EBIT interest coverage (x)	4.1	2.8	3.0	5.4	4.4	3.6
Return on capital (%)	10.2	9.5	8.4	9.6	8.5	9.0
FFO/debt (%)	19.9	22.9	22.7	26.9	22.1	22.2
Free operating cash flow/debt (%)	1.0	5.8	3.3	9.6	0.9	9.6
Debt/EBITDA (x)	3.9	3.5	3.9	3.2	3.9	3.6
Debt/debt plus equity (%)	58.8	53.8	58.3	45.6	51.4	51.8

Table 2

AGL Resources Inc.--Financial Summary					
Industry Sector: Gas					
	--Fiscal year ended Dec. 31--				
	2010	**2009**	**2008**	**2007**	**2006**
Rating history	A-/Watch Neg/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Negative/A-2
(Mil. $)					
Revenues	2,373.0	2,317.0	2,800.0	2,494.0	2,621.0
EBITDA	681.5	654.4	638.2	647.6	641.6
Net income from cont. oper.	234.0	222.0	217.0	211.0	212.0
Funds from operations (FFO)	535.1	523.5	457.4	421.0	569.7
Capital expenditures	510.5	468.7	371.8	273.9	277.1
Free operating cash flow	50.6	150.8	(128.5)	123.1	98.6
Discretionary cash flow	(109.4)	3.8	(252.5)	(22.9)	(34.4)
Cash and short-term investments	24.0	26.0	16.0	19.0	20.0
Debt	2,676.4	2,509.9	2,426.8	2,157.6	2,061.9
Equity	1,836.0	1,819.0	1,684.0	1,708.0	1,651.0
Adjusted ratios					
EBITDA margin (%)	28.7	28.2	22.8	26.0	24.5
EBITDA interest coverage (x)	5.8	5.5	4.9	4.7	4.7
EBIT interest coverage (x)	4.4	4.1	3.7	3.7	3.6
Return on capital (%)	10.0	10.2	10.6	11.5	12.1
FFO/debt (%)	20.0	20.9	18.8	19.5	27.6
Free operating cash flow/debt (%)	1.9	6.0	(5.3)	5.7	4.8
Debt/EBITDA (x)	3.9	3.8	3.8	3.3	3.2
Debt/debt plus equity (%)	59.3	58.0	59.0	55.8	55.5

Table 3

Reconciliation Of AGL Resources Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

--Rolling 12 months ended Sept. 30, 2011--								
AGL Resources Inc. reported amounts								
	Debt	**Shareholders' equity**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Capital expenditures**
Reported	2,704.0	1,881.0	626.0	459.0	120.0	536.0	536.0	432.0
Standard & Poor's adjustments								
Operating leases	137.5	--	5.7	5.7	5.7	2.8	2.8	53.6
Postretirement benefit obligations/deferred compensation	145.0	--	--	--	1.0	54.0	54.0	--
Capitalized interest	--	--	--	--	(1.0)	1.0	1.0	1.0
Share-based compensation expense	--	--	8.0	--	--	--	--	--
Non-operating income (expense)	--	--	--	34.0	--	--	--	--
Changes in assets and liabilities	--	--	--	--	--	--	49.0	--
Debt - Accrued interest not included in reported debt	35.0	--	--	--	--	--	--	--
Total adjustments	317.5	0.0	13.7	39.7	5.7	57.7	106.7	54.6
	Debt	**Equity**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Capital expenditures**
Adjusted	3,021.5	1,881.0	639.7	498.7	125.7	593.7	642.7	486.6

Related Criteria And Research

2008 Corporate Criteria: Analytical Methodology, April 15, 2008

Ratings Detail (As Of January 3, 2012)	
AGL Resources Inc.	
Corporate Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured (5 Issues)	BBB+
Corporate Credit Ratings History	
15-Dec-2011	BBB+/Stable/A-2
07-Dec-2010	A-/Watch Neg/A-2
12-Dec-2007	A-/Stable/A-2
Business Risk Profile	Excellent
Financial Risk Profile	Significant

Ratings Detail (As Of January 5, 2012) (cont.)	
Related Entities	
AGL Capital Corp.	
Senior Unsecured (2 Issues)	BBB+
Atlanta Gas Light Co.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured (7 Issues)	BBB+
Nicor Gas Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured (6 Issues)	A
Pivotal Utility Holdings	
Issuer Credit Rating	BBB+/Stable/--

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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February 2, 2012

Alliant Energy Corp.

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Table Of Contents

Alliant Energy Corp.

Major Rating Factors

Corporate Credit Rating

BBB+/Stable/A-2

Strengths:

- Predictable cash flow from regulated utilities,
- A mostly regulated utility strategy; and
- More credit supportive regulatory jurisdictions.

Weaknesses:

- Aggressive capital spending,
- Dependence on supportive cost recovery; and
- Weakening financial measures.

Rationale

Standard & Poor's Ratings Services bases its rating on Alliant Energy Corp. on the consolidated credit profile that consists of an "excellent" business risk profile and a "significant" financial risk profile (as our criteria define the terms). Alliant, a regional utility holding company, owns electric generation and distribution and natural gas distribution utility subsidiaries Interstate Power & Light Co. (IPL), which serves customers in Iowa and Minnesota, and Wisconsin Power & Light Co. (WPL), which operates in Wisconsin. We assume that electricity use in these service territories will continue to steadily grow.

Our rating on Alliant reflects a mostly regulated utility strategy that includes high levels of capital spending and a dependence on timely cost recovery of these expenditures and related operating expenses. We expect this, along with the phaseout of bonus depreciation, to weaken cash flow measures over time. However, we expect debt leverage to remain manageable. In addition to the two utilities, Alliant owns part of the American Transmission Co LLC and has an unregulated subsidiary, Alliant Energy Resources LLC (AER), which operates a short-haul railroad and barge business and a renewable energy engineering and construction business.

We consider Alliant's business risk profile to be excellent due to stable cash flows from IPL and WPL that, combined, deliver low-cost electricity and natural gas to customers in jurisdictions in which we consider the regulatory environment to be very credit supportive. Moderate industrial concentration, a large construction program, and the need for ongoing rate relief during a weak economy moderate the strengths of the utilities. Also reflected in the business risk profile is a scaled down AER after divestitures of unregulated and international activities. As the utilities continue to spend on generation and renewable investments, operating cash flow has risen through rate riders, forecasted test periods, and earning a return on construction work in progress. IPL's and WPL's business risk profiles are "excellent," in our assessment.

Alliant's significant financial risk profile reflects adjusted consolidated financial measures that have been more than sufficient for the rating. In addition, we consider the company's financial policies to be credit-supportive and transparent. Over the next few years we project financial measures will remain in line for the rating, albeit with less cushion for the significant financial risk profile. Even with lower industrial and wholesale sales, as full cost recovery of larger construction projects is incorporated into operating cash flow, financial measures could improve in the outer years. For the 12 months ended Sept. 30, 2011, funds from operations (FFO) to total debt and debt to total capital were 26% and 53%, respectively. Debt to EBITDA was 3.7x. Also, the company was free operating cash flow positive for the 12 months ended Sept. 30, 2011. Discretionary cash flow continues to be negative after dividend payments and net cash flow (FFO less dividends) to capital expenditures remained well below 100%, at 84%, indicating a need for external funding to finance capital spending. FFO interest coverage was a robust 5.5x.

Under our base forecast, we expect financial measures will weaken to the point where FFO to debt approximates 16%, debt to EBITDA remains around 4x, and debt to total capital averages around 55%. We also expect net cash flow to capital expenditures to be around 50% and discretionary cash flow to remain materially negative over the next several years. We project that FFO interest coverage will fall below 4x. These weaker financials reflect declining FFO over the next few years, partly from the phaseout of bonus depreciation. Also, we expect debt leverage to climb as the company spends on environmental and generation investments. The consolidated adjustments for Alliant reflect purchased-power obligations, operating leases, and pension-related items, and intermediate equity treatment of the preferred stock.

Liquidity

The short-term rating on Alliant is 'A-2'. We consider Alliant's liquidity "adequate" (as our criteria define the term) under Standard & Poor's liquidity methodology. We base our liquidity assessment on the following factors and assumptions:

- We expect Alliant's liquidity sources over the next 12 months, including cash, FFO, and credit facility availability, to exceed uses by 1.2x. Uses include necessary capital spending, working capital, debt maturities, and shareholder distributions.
- Debt maturities are manageable over the next 12 months.
- We believe liquidity sources would exceed uses even if EBITDA declined 15%.
- In our assessment, Alliant has good relationships with its banks, and has a good standing in the credit markets, having successfully issued debt during the recent credit crisis.

In our analysis of liquidity over the next 12 months, we assume \$2.1 billion of liquidity sources, consisting of FFO and credit facility availability. We estimate liquidity uses of \$1.5 billion for capital spending, maturing debt, working capital, and shareholder distributions.

Alliant's credit agreements include a financial covenant requiring that debt to total capitalization be no greater than 65%. As of Sept. 30, 2011, the company was in compliance with the covenant at 45%.

Debt maturities are very manageable through 2015, with \$300 million due in 2014, and about \$180 million due in 2015. The next significant maturity is in 2018 when approximately \$360 million is due. We expect that the company will refinance a majority of its maturing debt.

Outlook

The stable outlook on Alliant reflects our expectations that management will continue to focus on its core utility operations and reach constructive regulatory outcomes to avoid any meaningful rise in business risk. The outlook also takes into account our projection that cash flow measures will decline as construction projects move forward and the benefits of bonus depreciation recede. Specifically, our base forecast includes FFO to total debt of more than 16%, debt to EBITDA of approximately 4x, and debt to total capital averaging around 55%, consistent with our expectations for the rating.

We could raise ratings if financial measures strengthen and consistently exceed our base forecast, including FFO to total debt greater than 20%, debt to EBITDA below 4x, and debt to total capital under 55%. We would expect the regulated utility operations to reach constructive regulatory outcomes to avoid higher business risk, particularly through the ongoing capital spending phase and a weak economy that has resulted in modest cash flow erosion from industrial load loss and lower wholesale sales. We could lower ratings if financial measures consistently underperform our base forecast and remain at less credit supportive levels, including FFO to total debt below 15%, debt to EBITDA over 4.5x, and debt leverage over 58%.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Ratios And Adjustments, April 15, 2008
- Analytical Methodology, April 15, 2008
- Assessing U.S. Utility Regulatory Environments, Nov. 7, 2007

Table 1

Alliant Energy Corp. -- Peer Comparison

Industry Sector: Energy

	Alliant Energy Corp.	**Wisconsin Energy Corp.**	**Great Plains Energy Inc.**	**Westar Energy Inc.**	**SCANA Corp.**
Rating as of Jan. 31, 2012	BBB+/Stable/A-2	A-/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2	BBB+/Stable/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	3,510.2	4,253.8	1,963.5	1,917.8	4,719.0
EBITDA	874.9	807.4	723.3	661.9	1,094.4
Net income from cont. oper.	239.1	396.7	160.9	174.5	359.7
Funds from operations (FFO)	777.3	968.4	430.1	535.4	776.5
Capital expenditures	1,052.4	898.1	871.2	669.8	897.3
Free operating cash flow	(338.6)	106.0	(430.2)	(183.0)	(266.1)
Discretionary cash flow	(506.5)	(66.4)	(576.0)	(303.8)	(495.6)
Cash and short-term investments	227.2	90.8	49.1	9.2	163.0
Debt	3,418.7	5,426.0	4,029.6	3,487.1	5,257.1
Equity	2,953.9	3,833.8	2,955.0	2,287.6	3,453.8
Adjusted ratios					
EBITDA margin (%)	24.9	19.0	36.8	34.5	23.2
EBITDA interest coverage (x)	4.5	3.2	3.4	3.7	3.8
EBIT interest coverage (x)	3.0	2.1	2.1	2.3	2.8
Return on capital (%)	8.1	5.3	6.6	6.3	8.5
FFO/debt (%)	22.7	17.8	10.7	15.4	14.8

Table 1

Alliant Energy Corp. -- Peer Comparison (cont.)					
Free operating cash flow/debt (%)	(9.9)	2.0	(10.7)	(5.2)	(5.1)
Debt/EBITDA (x)	3.9	6.7	5.6	5.3	4.8
Total debt/debt plus equity (%)	53.6	58.6	57.7	60.4	60.4

Table 2

Alliant Energy Corp. -- Financial Summary					
Industry Sector: Energy					
	--Fiscal year ended Dec. 31--				
	2010	**2009**	**2008**	**2007**	**2006**
Rating history	BBB+/Positive/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2
(Mil. $)					
Revenues	3,416.1	3,432.8	3,681.7	3,437.6	3,359.4
EBITDA	973.5	820.0	830.8	935.5	815.7
Net income from continuing operations	308.0	129.4	280.0	424.7	338.3
Funds from operations (FFO)	893.1	780.2	656.8	675.5	684.8
Capital expenditures	927.6	1,270.0	959.7	621.2	402.5
Dividends paid	184.0	174.9	145.0	133.9	125.1
Debt	3,595.4	3,443.0	3,285.3	2,898.3	3,163.1
Preferred stock	121.9	121.9	121.9	121.9	121.9
Equity	3,017.5	2,896.6	2,947.5	2,807.0	2,778.1
Debt and equity	6,612.9	6,339.6	6,232.8	5,705.3	5,941.2
Adjusted ratios					
EBITDA margin (%)	28.5	23.9	22.6	27.2	24.3
EBIT interest coverage (x)	3.3	2.6	3.2	3.5	2.3
FFO interest coverage (x)	5.3	4.5	4.5	4.4	4.0
FFO/debt (%)	24.8	22.7	20.0	23.3	21.7
Discretionary cash flow/debt (%)	(3.7)	(19.3)	(22.0)	(0.8)	0.4
Net cash flow/capital expenditures (%)	76.5	47.7	53.3	87.2	139.1
Debt/debt and equity (%)	54.4	54.3	52.7	50.8	53.2
Return on capital (%)	8.5	7.4	8.4	9.5	7.4
Return on common equity (%)	9.6	2.5	8.3	14.7	12.2
Common dividend payout ratio (unadjusted) (%)	60.4	149.5	59.1	35.3	42.1

Table 3

Reconciliation Of Alliant Energy Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)										
	--Fiscal year ended Dec. 31, 2010--									
Alliant Energy Corp. reported amounts										
	Debt	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	2,752.1	3,139.4	3,416.1	847.4	556.1	156.2	984.9	984.9	193.3	866.9

Table 3

Reconciliation Of Alliant Energy Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Standard & Poor's adjustments										
Trade receivables sold or securitized	65.0	--	--	--	--	1.6	(65.0)	--	--	--
Operating leases	90.3	--	--	5.6	5.6	5.6	9.9	9.9	--	4.3
Intermediate hybrids reported as equity	121.9	(121.9)	--	--	--	9.4	(9.4)	(9.4)	(9.4)	--
Postretirement benefit obligations	183.4	--	--	28.6	28.6	--	7.3	7.3	--	--
Capitalized interest	--	--	--	--	--	6.8	(6.8)	(6.8)	--	(6.8)
Share-based compensation expense	--	--	--	7.5	--	--	--	--	--	--
Power purchase agreements	286.7	--	--	80.4	17.2	17.2	63.2	63.2	--	63.2
Asset retirement obligations	49.3	--	--	4.1	4.1	4.1	(8.2)	(8.2)	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	53.3	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	(149.6)	--	--
Accrued interest not included in reported debt	46.7	--	--	--	--	--	--	--	--	--
Funds from operations -- other	--	--	--	--	--	--	1.7	1.7	--	--
Total adjustments	843.3	(121.9)	--	126.1	108.7	44.6	(7.2)	(91.8)	(9.4)	60.7
Standard & Poor's adjusted amounts										
	Debt	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	3,595.4	3,017.5	3,416.1	973.5	664.8	200.8	977.7	893.1	184.0	927.6

Ratings Detail (As Of February 2, 2012)

Alliant Energy Corp.	
Corporate Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2

Ratings Detail (As Of February 2, 2012) **(cont.)**	
Senior Unsecured (1 Issue)	BBB
Corporate Credit Ratings History	
24-Jan-2012	BBB+/Stable/A-2
23-Jul-2010	BBB+/Positive/A-2
05-Jan-2006	BBB+/Stable/A-2
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
Alliant Energy Resources LLC	
Issuer Credit Rating	BBB+/Stable/NR
Interstate Power & Light Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB-
Senior Unsecured (9 Issues)	BBB+
Wisconsin Power & Light Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (7 Issues)	BBB
Senior Unsecured (7 Issues)	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

STANDARD & POOR'S

Global Credit Portal
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March 30, 2012

Atmos Energy Corp.

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Table Of Contents

Atmos Energy Corp.

Major Rating Factors

Corporate Credit Rating
BBB+/Stable/A-2

Strengths:

- A low-risk monopoly gas distribution and pipeline business;
- A large, stable residential and commercial customer base; and
- Geographic and regulatory diversity in regulated operations.

Weaknesses:

- A significant financial risk profile characterized by high leverage and weak cash flow measures;
- Higher business risks and volatile cash flow associated with nonregulated operations; and
- A history of pursuing sizable acquisitions.

Rationale

Standard & Poor's Ratings Services' ratings on Dallas-based Atmos Energy Corp. (Atmos) reflect our assessment of the company's business risk profile as excellent and its financial risk profile as significant. Our rating is based on the consolidated business and financial risk of the company, including the nonregulated operations. The rating balances the strong cash flow generated by the regulated gas distribution and pipeline operations (which we expect will contribute more than 85% of consolidated cash flows in 2012) with the more volatile cash flows that natural gas marketing operations contribute.

Key credit factors include favorable regulatory oversight; the company's position as one of the largest natural gas local distribution companies in the U.S., with operations in nine states (although about 60% of total customers are in Texas); and the low operating risks of its regulated utilities. A large residential customer base, lack of competition in the company's regulated service territories, and high barriers to entry provided by the capital-intensive nature of the distribution network also support the business risk profile. Atmos' financial risk profile, which has high leverage and weak cash flow metrics; its higher-risk, nonregulated operations; and its history of pursuing sizable acquisitions somewhat temper the company's strengths.

The company generally maintains constructive relationships with the utility commissions in the states where it operates, which results in stable revenues and cash flow. Cash flows also benefit from a favorable regulatory environment, including coverage of about 90% of its customers by weather-normalization clauses. In several jurisdictions, Atmos also benefits from revenue-stabilization mechanisms (similar to decoupling) and fuel-adjustment clauses, which serve to further stabilize cash flows. We expect the company's plan to sell gas distribution assets in Missouri, Illinois, and Iowa to have minimal impact on overall cash flows because this sale represents less than 3% of Atmos' 3 million customers.

The company's regulated transmission and storage segment (which we expect to provide about 20% of net income in 2011) transports natural gas to Atmos' Mid-Tex division, transports natural gas for third parties, and manages underground storage reservoirs in Texas. This is a strategic asset because it supplies gas to a substantial proportion of Atmos' distribution network and provides access to natural gas from several basins in Texas, which have substantial reserves. We expect this segment to generate relatively stable cash flow.

Standard & Poor's regards the Atmos Energy Marketing LLC (AEM) segment as the company's riskiest. Operating primarily in the Midwest and southeastern U.S., AEM purchases natural gas and related transportation and storage needs for its customers. In addition, this segment uses financial instruments to hedge purchases of natural gas and benefits from the seasonal spread in natural gas prices. Volatile natural gas prices can create profit opportunities for AEM, but such profits are not recurring in nature. In current market conditions, we expect this segment to generate relatively modest cash flows. The AEM segment can also create significant swings in cash-posting requirements related to hedging, and requires stringent risk-management oversight.

Our assessment of Atmos' financial risk profile as significant reflects the company's stable regulated cash flows, relatively high leverage, and the volatility associated with its nonregulated marketing operations. Notwithstanding the volatility associated with AEM's financial performance, bondholder protection measures have improved since the fiscal 2005 acquisition of TXU Gas and are currently adequate for the rating. In 2012, we expect funds from operations (FFO) to total debt to be about 20%, and FFO interest coverage of 4.9x, in line with recent quarters. Bonus depreciation, which results in low cash taxes paid, also helped the cash flows over the past two years. In future years, we expect this benefit to be less meaningful. The company recently declared a share-repurchase program. Given the size of the program and assuming the company will finance these from excess cash flows, we don't anticipate any significant effect on key credit metrics.

Short-term credit factors

The short-term rating on Atmos is 'A-2'. We currently deem Atmos' liquidity to be adequate under Standard & Poor's corporate liquidity methodology, which categorizes liquidity in five standard descriptors: exceptional, strong, adequate, less than adequate, and weak.

Over the next 12 months, the company's FFO will be its largest liquidity source. As per our assumptions, we expect it to be about $600 million for 2012. Atmos has a $750 million revolving credit facility on which about $550 million is available for future borrowings. In addition, AEM has a three-year $200 million credit facility that expires in 2013. However, only about $120 million is available on the AEM facility due to the borrowing restrictions based on total collateral.

Our assumptions for projected uses of cash include maintenance and significant discretionary capital spending of about $350 million and total capital spending of about $650 million in 2012. We also estimated shareholder distributions of about $125 million over the next year. Atmos must occasionally post collateral related to derivative transactions, although these amounts have been relatively modest in recent years. Finally, working capital can swing widely during the year as the company purchases natural gas in advance of the heating season. Working capital needs tend to peak in the winter; however, the company has adequate liquidity to meet those needs.

There is significant covenant headroom under Atmos' debt agreements, with total debt to capital (as defined) of 56% as of Dec. 31, 2011, compared with the requirement to maintain leverage below 70%. The credit facility expires in May 2016.

Outlook

The stable rating outlook on Atmos reflects our expectation that the company will maintain its current level of financial performance, with adjusted FFO to total debt around 20%, coupled with continued satisfactory management of its working capital and liquidity needs. We could revise the outlook to negative if we expect that adjusted FFO to total debt will consistently fall below 20% or if the cash flows from nonregulated operations increase significantly. An outlook revision to positive would require a sustained FFO to total debt around the mid-20% area, or a reduction in the company's business risks.

Related Criteria And Research

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Key Credit Factors: Business And Financial Risks In the Investor-Owned Utilities Industry, Nov. 26, 2008
- Key Credit Factors For U.S. Natural Gas Distributors, Feb. 28, 2006

Table 1

Atmos Energy Corp. -- Peer Comparison

Industry Sector: Gas

	Atmos Energy Corp.	AGL Resources Inc.	South Jersey Industries Inc.	Sempra Energy	Vectren Corp.
Rating as of March 29, 2012	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/--	BBB+/Stable/A-2	A-/Stable/--
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	4,702.1	2,342.7	866.4	9,048.3	2,181.2
EBITDA	736.5	685.8	167.8	3,429.6	555.8
Net income from cont. oper.	198.6	209.3	71.7	1,071.7	136.1
Funds from operations (FFO)	588.8	542.8	159.7	2,326.1	466.6
Capital expenditures	568.5	504.0	158.6	2,278.6	343.2
Free operating cash flow	164.2	56.4	22.0	(93.5)	87.6
Discretionary cash flow	40.9	(100.6)	(18.6)	(484.5)	(23.2)
Cash and short-term investments	124.9	57.3	4.6	424.7	10.3
Debt	2,568.3	3,415.5	785.4	12,355.5	1,971.0
Equity	2,203.5	2,331.3	579.6	9,655.7	1,445.1
Adjusted ratios					
EBITDA margin (%)	15.7	29.3	19.4	37.9	25.5
EBITDA interest coverage (x)	4.1	5.4	6.1	5.2	5.1
EBIT interest coverage (x)	2.8	4.0	5.0	3.5	2.9
Return on capital (%)	9.3	8.8	8.9	10.1	8.2
FFO/debt (%)	22.9	15.9	20.3	18.8	23.7
Free operating cash flow/debt (%)	6.4	1.7	2.8	(0.8)	4.4
Debt/EBITDA (x)	3.5	5.0	4.7	3.6	3.5
Total debt/debt plus equity (%)	53.8	59.4	57.5	56.1	57.7

Table 2

Atmos Energy Corp. -- Financial Summary

Industry Sector: Gas	--Fiscal year ended Sept. 30--				
	2011	2010	2009	2008	2007
Rating history	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB/Positive/A-2	BBB/Positive/A-2
(Mil. $)					
Revenues	4,347.6	4,789.7	4,969.1	7,221.3	5,898.4
EBITDA	744.5	749.1	716.0	668.9	644.5
Net income from continuing operations	198.9	205.8	191.0	180.3	168.5
Funds from operations (FFO)	587.7	630.7	547.9	533.8	481.9
Capital expenditures	621.3	554.2	530.0	482.6	397.5
Free operating cash flow	(59.4)	160.0	391.9	(121.5)	140.3
Discretionary cash flow	(183.4)	35.7	270.5	(238.8)	28.6
Cash and short-term investments	131.4	132.0	111.2	46.7	60.7
Debt	2,668.4	2,471.6	2,564.9	2,431.5	2,414.0
Equity	2,255.4	2,178.3	2,176.8	2,052.5	1,965.8
Adjusted ratios					
EBITDA margin (%)	17.1	15.6	14.4	9.3	10.9
EBITDA interest coverage (x)	4.3	4.2	3.9	4.2	3.9
EBIT interest coverage (x)	2.9	2.9	2.6	2.9	2.7
Return on capital (%)	8.8	9.6	9.4	9.4	9.7
FFO/debt (%)	22.0	25.5	21.4	22.0	20.0
Free operating cash flow/debt (%)	(2.2)	6.5	15.3	(5.0)	5.8
Debt/EBITDA (x)	3.6	3.3	3.6	3.6	3.7
Debt/debt and equity (%)	54.2	53.2	54.1	54.2	55.1

Table 3

Reconciliation Of Atmos Energy Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

	--Fiscal year ended Sept. 30, 2011--									
Atmos Energy Corp. reported amounts										
	Debt	Shareholders' equity	Revenues	EBITDA	Operating income	Interest expense	Cash flow from operations	Cash flow from operations	Dividends paid	Capital expenditures
Reported	2,414.9	2,255.4	4,347.6	699.3	441.9	150.8	582.8	582.8	124.0	623.0
Standard & Poor's adjustments										
Operating leases	138.2	--	--	8.6	8.6	8.6	9.4	9.4	--	--
Postretirement benefit obligations	275.2	--	--	25.0	25.0	13.4	(16.4)	(16.4)	--	--
Capitalized interest	--	--	--	--	--	1.7	(1.7)	(1.7)	--	(1.7)
Share-based compensation expense	--	--	--	11.6	--	--	--	--	--	--
Asset retirement obligations	8.8	--	--	--	--	--	(3.5)	(3.5)	--	--

Table 3

Reconciliation Of Atmos Energy Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)										
Reclassification of nonoperating income (expenses)	--	--	--	--	(6.3)	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	25.8	--	--
Debt - Accrued interest not included in reported debt	37.6	--	--	--	--	--	--	--	--	--
Debt - Other	(206.4)	--	--	--	--	--	--	--	--	--
D&A - Impairment charges/(reversals)	--	--	--	--	30.3	--	--	--	--	--
FFO - Discontinued Operations	--	--	--	--	--	--	(8.7)	(8.7)	--	--
Total adjustments	253.4	0.0	0.0	45.2	57.6	23.6	(20.9)	4.9	0.0	(1.7)

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	2,668.4	2,255.4	4,347.6	744.5	499.5	174.5	561.9	587.7	124.0	621.3

Ratings Detail (As Of March 30, 2012)	
Atmos Energy Corp.	
Corporate Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured (8 Issues)	BBB+
Corporate Credit Ratings History	
23-Dec-2008	BBB+/Stable/A-2
11-Jun-2007	BBB/Positive/A-2
30-Sep-2004	BBB/Stable/A-2
Business Risk Profile	Excellent
Financial Risk Profile	Significant

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

October 29, 2011

Consolidated Edison Inc.

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Table Of Contents

Consolidated Edison Inc.

Major Rating Factors

Corporate Credit Rating
A-/Stable/A-2

Strengths:

- Low-operating-risk electric and natural gas transmission and distribution operations;
- Ability to achieve constructive regulatory outcomes;
- Large and diversified service territory; and
- Lack of competitive pressures in service territory.

Weaknesses:

- Large capital spending program;
- High-cost operating environment; and
- While unregulated business contribution is small, it influences business risk.

Rationale

Standard & Poor's Ratings Services' ratings on Consolidated Edison Inc. (Con Edison) reflect the consolidated credit profiles of its regulated subsidiaries, Consolidated Edison Co. of New York Inc. (CECONY) and Orange and Rockland Utilities Inc. (O&R), as well as Con Edison's nonregulated activities, which include retail and wholesale energy supply.

Con Edison has an excellent business risk profile that largely reflects the company's low-operating-risk electric and gas transmission and distribution (T&D) operations and a conservative growth strategy. The service territory is large, with a diverse economy, and has recently experienced modest customer growth.

CECONY is Con Edison's largest subsidiary, serving about 3.3 million electric customers and about 1.1 million natural gas customers in New York City and Westchester County; it also provides steam service in parts of Manhattan. The company has an excellent business risk profile and provides about 90% of consolidated operating income. O&R and subsidiary Rockland Electric Co. provide electric service to about 300,000 customers in southeastern New York and adjacent sections of New Jersey and northeastern Pennsylvania, as well as gas service to about 125,000 customers in southeastern New York and northeastern Pennsylvania. The electric utilities have sold almost all of their generation assets and provide their customers with the opportunity to buy electricity and gas directly from other suppliers through retail access programs. In addition to delivering energy, the utilities supply about half of the energy they deliver as providers of last resort and have no exposure to commodity prices. Con Edison's nonregulated activities contribute less than 10% of operating income and are focused on retail and wholesale electricity supply. Standard & Poor's Ratings Services views the electric supply business as having significantly higher business risk than the regulated utility operations have, which negatively affects the consolidated business risk profile, although not materially. We also believe the higher business risk necessitates that the company have strong credit protection measures and excellent risk management practices to preserve the current credit profile.

Because the operating subsidiaries are regulated T&D entities with no exposure to commodity prices, successful and effective management of regulatory relations becomes very important to recovering incurred capital expenditures and to supporting credit protection measures. Although Standard & Poor's views the regulatory environment in New York as less credit supportive, Con Edison's subsidiaries have endeavored to reach constructive multiyear settlements in their rate case filings, reducing the need for regular rate filings and ensuring cash flow stability. On March 25, 2010, the New York Public Service Commission (NYPSC) approved a settlement reached by CECONY and various interveners in its electric rate case. The settlement provided for levelized base-rate increases of $420 million annually from April 2010 to April 2013. In addition, the settlement included an allowed return on equity (ROE) of 10.15% (slightly higher than the rate case decision in 2009), continued the revenue decoupling mechanism, provided for earnings sharing with ratepayers, and prevents the utility from accruing financing costs for electric T&D capital expenditures above those included in the settlement ($1.2 billion in 2010 and a maximum of $2.3 billion for 2011 and 2012 combined).

In September 2010, the NYPSC approved CECONY's gas and steam rate case settlements, albeit with an ROE of 9.6%, which is lower than the historical authorized ROE levels, reflecting in part the still-recovering local economy and the low operating risk of the gas and steam distribution business. For the gas operations, the three-year settlement provided for rate increases of $47.1 million, $47.9 million, and $46.7 million annually starting in October 2010. For the steam operations, the three-year settlement provided for rate increases of $49.5 million in each of the first two years and $17.8 million in the third year, starting in October 2010, with an additional $31.7 million to be collected via a surcharge in the third year. Both the settlements provided for earnings sharing with ratepayers and continuation of the recovery of purchased gas and fuel costs, but the gas settlement also provided for the continuation of a weather normalization adjustment and a revenue decoupling mechanism.

For O&R, the company filed a new base rate increase in July 2010 for $61.7 million, effective July 2011, reflecting an ROE of 11% and a common equity layer of 49.9%.

Con Edison's consolidated financial risk profile is significant. For the 12 months ended June 30, 2011, Con Edison generated almost $3.5 billion in adjusted funds from operations (FFO) and had total adjusted debt of $13.44 billion, leading to adjusted total debt to total capital of about 54.2%, adjusted FFO interest coverage of 6.3x, and adjusted FFO to total debt of 25.9%. Credit measures were stronger in 2011 than in previous years, partly as a result of rate increases at CECONY and O&R, and partly because of deferred tax benefits. The adjusted measures reflect the off-balance-sheet debt imputation of about $2.8 billion resulting from the shortfall in pension and other postretirement liability funding. Although the financial profile should benefit from the approved base-rate increases, the large capital spending program and need for external financing will place some pressure on credit protection measures, necessitating an ongoing balanced funding approach.

Liquidity

The short-term rating on Con Edison and its subsidiaries is 'A-2', reflecting the combined entity's adequate liquidity and our expectation of continued stable cash flows. Liquidity is adequate under Standard & Poor's corporate liquidity methodology, which categorizes liquidity in five standard descriptors. (See "Liquidity Descriptors For Global Corporate Issuers," published on Sept. 28, 2011.) Adequate liquidity supports our 'A-' issuer credit rating on Con Edison. The company's projected sources of liquidity, mostly operating cash flow and available bank lines, exceed its projected uses, mainly necessary capital expenditures and debt maturities by more than 1.2x. Con Edison's ability to absorb high-impact, low-probability events with limited need for refinancing, its flexibility to lower capital spending or sell assets, its sound bank relationships, its solid standing in credit markets, and its generally prudent risk management further support our assessment of its liquidity as adequate.

The company has a $2.2 billion revolving credit facility maturing in June 2012, with about 2.0 billion available as of June 30, 2011. Con Edison's borrowings under the revolving credit facility are limited to $1 billion, O&R is limited up to $200 million, and CECONY may borrow up to the full amount of the line. Con Edison uses the revolving credit facility primarily to support its commercial paper obligations and to provide liquidity to the unregulated businesses.

Liquidity is adequate based on the following factors and assumptions:

- We expect the company's liquidity sources (including FFO and credit facility availability) over the next 12 months to exceed its uses by more than 1.2x.
- Debt maturities over the next year are manageable.
- Even if EBITDA declines by 15%, we believe net sources will be well in excess of liquidity requirements.
- The company has good relationships with its banks, in our assessment, and has a good standing in the credit markets.

In our analysis, based on information available as of June 30, 2011, we assumed liquidity of about $5.1 billion over the next 12 months, consisting of projected FFO and availability under the credit facility. We estimate liquidity uses of $3.1 billion during the same period for capital spending, dividends, and debt maturities.

Con Edison's credit agreement includes a financial covenant limiting the consolidated debt-to-capitalization ratio of no greater than 65%, with which the company was compliant as of June 30, 2011.

Debt maturities are manageable through 2014, with $5 million in 2011, $305 in 2012, $705 million in 2013, and $481 million in 2014. We expect that the company will refinance these debt maturities in a timely manner.

Outlook

The stable outlook on Con Edison and its affiliates reflects their stable cash flow generating capabilities, which should benefit from the recently approved rate increases but will be offset by the large capital spending program. The stable outlook also reflects our expectation that the unregulated business contribution will not grow materially beyond current levels, nor will it place an undue burden on the company's available liquidity. We expect Con Edison to achieve average FFO to total debt of at least 20% and adjusted debt leverage of no more than 55%.

We are not currently considering raising the rating, given the company's significant financial risk profile. We could lower the rating if credit protection measures weaken as a result of cost increases and the company is unable to recover such costs in a timely manner such that adjusted FFO interest coverage declines to below 4.0x, adjusted FFO to total debt declines to below 18%, and adjusted debt leverage approaches 60%.

Accounting

Con Edison's financial statements are prepared under U.S. GAAP and audited by independent auditors PricewaterhouseCoopers LLP who issued an unqualified opinion for 2010.

Standard & Poor's makes several adjustments to Con Edison's consolidated reported financial numbers. As of the end of 2010, Standard & Poor's makes an adjustment for operating leases that adds $227.6 million in debt equivalent, $12.6 million to interest expense, and $44 million to depreciation. In addition, Standard & Poor's adds

$2.136 billion as off-balance-sheet debt to reflect the pension funding shortfall.

Standard & Poor's views Con Edison's $213 million of preferred securities as of Dec. 31, 2010, as having intermediate equity content, ascribing 50% of each amount to debt and the remaining 50% to equity for ratio computation purposes. The total amount of the hybrid security is immaterial to the company's capital structure. In 2010, the adjustment for asset retirement obligations totaled $70.8 million in off-balance sheet.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

Table 1

Consolidated Edison Inc. -- Peer Comparison

Industry Sector: Combo

	Consolidated Edison Inc.	NSTAR	National Grid USA	Northeast Utilities	Iberdrola USA
Rating as of Oct. 27, 2011	A-/Stable/A-2	A+/Watch Neg/A-1	A-/Stable/A-2	BBB+/Watch Pos/--	A-/Stable/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	13,313.3	2,953.9	14,138.9	5,098.2	4,364.5
EBITDA	2,729.0	806.8	3,137.8	1,094.9	768.9
Net income from cont. oper.	934.7	239.2	479.6	330.2	94.9
Funds from operations (FFO)	2,093.1	552.6	2,293.6	797.8	524.3
Capital expenditures	2,189.1	397.8	1,625.6	1,028.0	483.2
Free operating cash flow	(202.7)	137.6	802.2	(337.8)	100.1
Dividends paid	617.8	159.7	300.1	158.2	59.7
Discretionary cash flow	(820.6)	(22.1)	502.1	(496.0)	40.4
Cash and short-term investments	224.0	59.5	897.1	121.1	87.0
Debt	13,471.0	3,198.0	12,641.6	5,749.4	4,360.2
Preferred stock	106.5	21.5	34.9	58.1	10.3
Equity	10,442.5	1,886.6	14,675.6	3,528.4	3,156.2
Debt and equity	23,913.5	5,084.6	27,317.2	9,277.8	7,516.4
Adjusted ratios					
EBITDA margin (%)	20.5	27.3	22.2	21.5	17.6
EBIT interest coverage (x)	3.2	3.9	2.8	3.0	1.7
Return on capital (%)	7.0	9.7	5.9	7.5	5.6
FFO int. cov. (X)	4.3	4.4	4.2	4.0	2.7
FFO/debt (%)	15.5	17.3	18.1	13.9	12.0
Free operating cash flow/debt (%)	(1.5)	4.3	6.3	(5.9)	2.3
Discretionary cash flow/debt (%)	(6.1)	(0.7)	4.0	(8.6)	0.9
Net cash flow/capex (%)	67.4	98.8	122.6	62.2	96.1

Table 1

Consolidated Edison Inc. -- Peer Comparison (cont.)					
Debt/EBITDA (x)	4.9	4.0	4.0	5.3	5.7
Total debt/debt plus equity (%)	56.3	62.9	46.3	62.0	58.0
Return on capital (%)	7.0	9.7	5.9	7.5	5.6
Return on common equity (%)	9.0	13.0	3.2	8.9	2.8
Common dividend payout ratio (un-adj.) (%)	70.9	67.9	62.7	48.7	62.1

Table 2

Consolidated Edison Inc. -- Financial Summary					
Industry Sector: Combo					
	--Fiscal year ended Dec. 31--				
	2010	**2009**	**2008**	**2007**	**2006**
Rating history	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-2	A/Negative/A-2
(Mil. $)					
Revenues	13,325.0	13,032.0	13,583.0	13,120.0	12,137.0
EBITDA	3,069.6	2,763.5	2,353.8	2,421.3	2,183.8
Net income from continuing operations	1,003.0	879.0	922.0	925.0	738.0
Funds from operations (FFO)	2,823.4	2,199.7	1,256.2	1,451.3	1,382.2
Capital expenditures	2,056.6	2,196.7	2,314.1	1,935.8	1,847.0
Dividends paid	634.5	606.5	612.5	576.5	527.5
Debt	13,447.8	13,407.0	13,558.2	10,307.5	9,718.2
Preferred stock	106.5	106.5	106.5	106.5	106.5
Equity	11,167.5	10,355.5	9,804.5	8,615.8	7,672.5
Debt and equity	24,615.3	23,762.5	23,362.7	18,923.3	17,390.7
Adjusted ratios					
EBITDA margin (%)	23.0	21.2	17.3	18.5	18.0
EBIT interest coverage (x)	3.5	3.1	3.0	3.2	2.6
FFO int. cov. (x)	5.3	4.3	3.2	3.4	3.1
FFO/debt (%)	21.0	16.4	9.3	14.1	14.2
Discretionary cash flow/debt (%)	0.2	(0.7)	(17.7)	(8.0)	(9.3)
Net cash flow/capex (%)	106.4	72.5	27.8	45.2	46.3
Debt/debt and equity (%)	54.6	56.4	58.0	54.5	55.9
Return on capital (%)	7.4	6.9	6.6	8.0	7.8
Return on common equity (%)	9.1	8.5	9.5	10.6	9.5
Common dividend payout ratio (un-adj.) (%)	68.1	74.8	70.1	62.9	77.6

Table 3

Reconciliation Of Consolidated Edison Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

--Fiscal year ended Dec. 31, 2010--

Consolidated Edison Inc. reported amounts

	Debt	Shareholders' equity	Revenues	EBITDA	Operating income	Interest expense	Cash flow from operations	Cash flow from operations	Dividends paid	Capital expenditures
Reported	10,683.0	11,274.0	13,325.0	2,960.0	2,120.0	609.0	2,381.0	2,381.0	640.0	2,014.0
Standard & Poor's adjustments										
Operating leases	227.6	--	--	12.6	12.6	12.6	31.4	31.4	--	51.6
Intermediate hybrids reported as equity	106.5	(106.5)	--	--	--	5.5	(5.5)	(5.5)	(5.5)	--
Postretirement benefit obligations	2,135.9	--	--	68.0	68.0	--	318.5	318.5	--	--
Capitalized interest	--	--	--	--	--	9.0	(9.0)	(9.0)	--	(9.0)
Share-based compensation expense	--	--	--	29.0	--	--	--	--	--	--
Asset retirement obligations	70.9	--	--	--	--	--	--	--	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	40.0	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	107.0	--	--
Debt - Accrued interest not included in reported debt	155.0	--	--	--	--	--	--	--	--	--
Debt - Guarantees	68.9	--	--	--	--	--	--	--	--	--
Total adjustments	2,764.8	(106.5)	0.0	109.6	120.6	27.1	335.4	442.4	(5.5)	42.6

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	13,447.8	11,167.5	13,325.0	3,069.6	2,240.6	636.1	2,716.4	2,823.4	634.5	2,056.6

Ratings Detail (As Of October 28, 2011)

Consolidated Edison Inc.	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2

Ratings Detail (As Of October 28, 2011) (cont.)	
Corporate Credit Ratings History	
25-Mar-2008	A-/Stable/A-2
06-Jun-2006	A/Negative/A-2
16-May-2003	A/Stable/A-1
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
Consolidated Edison Co. of New York Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (2 Issues)	BBB
Senior Secured (1 Issue)	A-
Senior Unsecured (46 Issues)	A-
Orange and Rockland Utilities Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured (1 Issue)	A-
Senior Unsecured (7 Issues)	A-
Rockland Electric Co.	
Issuer Credit Rating	A-/Stable/--

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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February 10, 2012

Integrys Energy Group Inc.

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Table Of Contents

Integrys Energy Group Inc.

Major Rating Factors

Strengths:

- Mostly lower-risk monopolistic, rate-regulated electric and gas businesses;
- Management's proactive efforts to decrease regulatory risk;
- Restructured, smaller size, lower-risk nonutility businesses; and
- Historically improved financial measures.

Corporate Credit Rating

A-/Stable/A-2

Weaknesses:

- A continued weak economy and slow growth could weaken cash flow over the medium term; and
- Increased capital spending over the medium term.

Rationale

The ratings on Integrys Energy Group Inc. reflect its "excellent" business risk profile and "significant" financial risk profile. (For more on business risk and financial risk, see "Business Risk/Financial Risk Matrix Expanded," published May 27, 2009, on RatingsDirect on the Global Credit Portal.)

Integrys's rate-regulated electric and gas utility subsidiaries include:

- Wisconsin Public Service Corp. (WPS);
- Peoples Gas Light & Coke Co. (PG), a subsidiary of intermediate holding company Peoples Energy Corp. (PE);
- North Shore Gas Co. (NSG), also a subsidiary of PE;
- Upper Peninsula Power Co.;
- Minnesota Energy Resources Corp.;
- Michigan Gas Utilities Corp.; and
- Rate-regulated American Transmission Co., of which Integrys owns 34%.

Integrys also owns nonutility Integrys Energy Services Inc. (ESI), a retail energy marketing company, and recently purchased a compressed natural gas refueling business.

Integrys's excellent business risk profile reflects the company's lower-risk monopolistic rate-regulated businesses, partially offset by nonutility businesses. Integrys has continued to effectively manage its regulatory risk--including its recent rate case orders for PG and NSG that will collectively raise rates by almost $60 million--which we view as credit supportive. We expect that the company will continue to effectively manage its regulatory risk over the medium term with the goal of further reducing its regulatory lag.

Over the past three years, Integrys has successfully implemented its strategic initiative to reduce its exposure to the nonutility businesses. Fundamentally, we anticipate that these improvements will be maintained over the intermediate term and expect that the nonutility businesses will account for about 10% of consolidated funds from operations (FFO) and the remaining 90% will represent the more stable cash flows of the regulated utility businesses. The nonutility energy marketing businesses operate in a highly competitive industry that is characterized by minimal barriers to entry, low margins, and volatile cash flows. The primary risks are matching supply to variable loads or estimated sales volumes and maintaining sufficient liquidity for collateral and margin calls. Although the company did reduce the size and scope of its energy marketing business, it did recently announce the purchase of a compressed natural gas refueling business and will increase its solar project investments through its partnership with Duke Energy. While we view the company's expansion into compressed natural gas and solar as a diversification of its nonutility businesses, we do not view these developments as a material overall reduction of the nonutility risk portfolio.

Integrys's significant financial risk profile reflects the company's improved financial measures, despite the recession and the restructuring of its ESI business.

Over the past three years, Integrys has significantly improved its financial measures primarily by increasing cash flow from its regulated subsidiaries, implementing effective cost management initiatives, and using bonus depreciation. For the 12 months ended Sept. 30, 2011, adjusted consolidated FFO to total debt improved to 29.3% from 25.2% at the end of 2010, adjusted debt to EBITDA improved to 3.5x from 3.8x, and adjusted debt to total capital strengthened to 47.8% from 50.7%.

Under our base-case scenario, while we forecast weaker financial measures over the intermediate term because of the continued slow economy and the phase-out of bonus depreciation, we expect that Integrys will maintain financial measures that are consistent with the significant financial risk profile, albeit with less cushion. Over the medium term, we forecast adjusted FFO to debt of about 21%, adjusted debt to EBITDA at about 4.0x, and adjusted debt to total capital at approximately 51%.

Integrys had positive discretionary cash flow in 2010 partially because of increased deferred taxes and reduced capital spending. However, over the intermediate term, we expect that discretionary cash flow will revert to negative primarily because of increased capital spending for environmental capital expenditures and the company's natural gas main replacement program. We expect that Integrys will meet these cash shortfalls in a manner that is at least credit neutral.

Liquidity

Our short-term rating on Integrys is 'A-2'. The company has adequate liquidity and can more than cover its needs for the next year, even if FFO declines. (For more on liquidity, see "Standard & Poor's Standardizes Liquidity Descriptors For Global Corporate Issuers," published July 2, 2010.)

We base our liquidity assessment on the following factors and assumptions:

- We expect the company's liquidity sources (including cash, FFO, and credit facility availability) over the next 12 months to exceed uses by about 1.7x.
- Debt maturities are manageable over the intermediate term, with about $250 million, $315 million, and $100 million maturing during 2012-2014.
- Even if the availability under the existing credit facilities and FFO declined by 25%, we believe net sources would total more than 1.2x cash requirements.
- The company has good relationships with its banks, in our assessment, and has a good standing in the credit markets, having successfully issued debt during the 2009 credit crisis.

In our analysis, we assumed liquidity of about $1.9 billion over the next 12 months, primarily consisting of cash, FFO, and availability under the credit facilities. We estimate the company will use about $1.1 billion over the same period for capital spending, debt maturities, working capital needs, and shareholder dividends.

Integrys's credit agreements include a financial covenant requiring that the consolidated ratio of total debt to total capital be no more than 65%. As of Sept. 30, 2011, the company had adequate cushion against this covenant and could increase total debt by more than 75% without violating it.

Outlook

The stable outlook on Integrys reflects Standard & Poor's baseline forecast that consolidated adjusted FFO to debt and debt to total capital will approximate 21% and 51%, respectively, over the intermediate term. Significant risks to the forecast include higher-than-anticipated capital costs, a weaker-than-expected economy, or materially lower rate case increases than predicted. We could lower the rating if the nonutility business disproportionally grows to greater than 15% of the consolidated company or FFO to debt weakens to below 18% on a consistent basis. We consider a ratings upgrade to be highly unlikely but could occur if the company's FFO to debt is consistently greater than 30%, its debt to total capital is lower than 45%, and Integrys maintains its excellent business risk profile.

Related Criteria And Research

- Standard & Poor's Standardizes Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

Table 1

Integrys Energy Group Inc. -- Peer Comparison

Industry Sector: Combo

	Integrys Energy Group Inc.	Alliant Energy Corp.	American Electric Power Co. Inc.	Dominion Resources Inc.	Wisconsin Energy Corp.
Rating as of Feb. 6, 2012	A-/Stable/A-2	BBB+/Stable/A-2	BBB/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	8,916.9	3,510.2	13,871.7	14,902.3	4,272.3
EBITDA	719.2	874.9	4,190.0	4,487.5	1,026.0
Net income from cont. oper.	92.7	239.1	1,314.7	1,886.0	448.1
Funds from operations (FFO)	806.6	777.3	3,256.9	3,141.0	974.4
Capital expenditures	453.9	1,052.4	3,182.0	3,624.2	788.6
Free operating cash flow	312.9	(338.6)	(568.1)	(549.2)	186.3
Discretionary cash flow	103.2	(506.5)	(1,330.7)	(1,676.2)	(19.3)
Cash and short-term investments	159.2	227.2	767.0	36.7	99.8
Debt	3,565.0	3,418.7	20,743.2	19,057.0	5,410.6
Equity	3,207.3	2,953.9	12,672.8	12,374.8	3,964.4
Adjusted ratios					
EBITDA margin (%)	8.1	24.9	30.2	30.1	24.0

Table 1

Integrys Energy Group Inc. -- Peer Comparison (cont.)					
EBITDA interest coverage (x)	4.0	4.5	3.6	4.6	4.1
EBIT interest coverage (x)	2.9	3.0	2.5	3.6	3.1
Return on capital (%)	7.0	8.1	7.7	10.3	7.4
FFO/debt (%)	22.6	22.7	15.7	16.5	18.0
Free operating cash flow/debt (%)	8.8	(9.9)	(2.7)	(2.9)	3.4
Debt/EBITDA (x)	5.0	3.9	5.0	4.2	5.3
Total debt/debt plus equity (%)	52.6	53.6	62.1	60.6	57.7

Table 2

Integrys Energy Group Inc. -- Financial Summary					
Industry Sector: Combo					
	--Fiscal year ended Dec. 31--				
	2010	**2009**	**2008**	**2007**	**2006**
Rating history	BBB+/Stable/A-2	BBB+/Negative/A-2	A-/Negative/A-2	A-/Stable/A-2	A/Watch Neg/A-1
(Mil. $)					
Revenues	5,203.2	7,499.8	14,047.8	10,292.4	6,890.7
EBITDA	860.2	773.6	523.9	624.1	409.4
Net income from continuing operations	223.8	(70.6)	124.8	181.1	151.6
Funds from operations (FFO)	822.3	860.2	737.3	388.5	304.2
Capital expenditures	294.9	495.3	571.6	432.3	362.3
Dividends paid	196.8	217.6	214.6	187.9	97.6
Debt	3,264.7	3,371.6	4,058.7	3,157.3	2,343.2
Preferred stock	175.6	175.6	175.6	175.6	175.6
Equity	3,170.3	3,176.6	3,275.2	3,411.4	1,709.2
Debt and equity	6,435.0	6,548.2	7,333.8	6,568.7	4,052.4
Adjusted ratios					
EBITDA margin (%)	16.5	10.3	3.7	6.1	5.9
EBIT interest coverage (x)	3.7	3.1	2.0	2.6	2.7
FFO int. cov. (x)	5.7	5.5	5.2	3.0	3.3
FFO/debt (%)	25.2	25.5	18.2	12.3	13.0
Discretionary cash flow/debt (%)	11.4	27.7	(24.5)	(11.3)	(15.5)
Net cash flow/capex (%)	212.1	129.7	91.4	46.4	57.1
Debt/debt and equity (%)	50.7	51.5	55.3	48.1	57.8
Return on capital (%)	8.6	7.8	4.8	8.4	9.4
Return on common equity (%)	7.6	(2.7)	3.6	7.4	10.4
Common dividend payout ratio (un-adj.) (%)	94.6	(280.7)	167.5	99.4	64.6

Table 3

Reconciliation Of Integrys Energy Group Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

	--Fiscal year ended Dec. 31, 2010--						
Integrys Energy Group Inc. reported amounts							
	Debt	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**
Reported	2,648.5	2,957.0	5,203.2	759.1	493.3	147.9	725.2
Standard & Poor's adjustments							
Operating leases	43.6	--	--	2.7	2.7	2.7	8.0
Intermediate hybrids reported as debt	(150.0)	150.0	--	--	--	(9.2)	9.2
Intermediate hybrids reported as equity	25.6	(25.6)	--	--	--	1.6	(1.6)
Postretirement benefit obligations	365.7	--	--	11.2	11.2	--	89.5
Capitalized interest	--	--	--	--	--	0.3	(0.3)
Share-based compensation expense	--	--	--	22.4	--	--	--
Power purchase agreements	303.1	--	--	53.1	16.7	16.7	36.4
Asset retirement obligations	192.5	--	--	11.7	11.7	11.7	(3.4)
Reclassification of nonoperating income (expenses)	--	--	--	--	91.6	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--
Debt - Other	(164.3)	--	--	--	--	--	--
Equity - Other	--	88.9	--	--	--	--	--
Total adjustments	616.2	213.3	0.0	101.1	133.9	23.8	137.9
Standard & Poor's adjusted amounts							
	Debt	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**
Adjusted	3,264.7	3,170.3	5,203.2	860.2	627.2	171.7	863.1

Ratings Detail (As Of February 10, 2012)

Integrys Energy Group Inc.	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated (1 Issue)	BBB
Senior Unsecured (3 Issues)	BBB+
Corporate Credit Ratings History	
24-Jan-2012	A-/Stable/A-2
21-Jan-2011	BBB+/Positive/A-2
26-Jan-2010	BBB+/Stable/A-2
05-Mar-2009	BBB+/Negative/A-2
25-Nov-2008	A-/Negative/A-2
13-Nov-2007	A-/Stable/A-2

Ratings Detail (As Of February 10, 2012) (cont.)	
21-Feb-2007	A-/Negative/A-2
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
North Shore Gas Co.	
Issuer Credit Rating	A-/Stable/NR
Senior Secured (2 Issues)	A
Peoples Energy Corp.	
Issuer Credit Rating	A-/Stable/NR
The Peoples Gas Light & Coke Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured (7 Issues)	A-
Senior Secured (1 Issue)	AA+/Negative
Wisconsin Public Service Corp.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (5 Issues)	BBB
Senior Secured (8 Issues)	A

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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June 29, 2011

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Table Of Contents

Northwest Natural Gas Co.

Major Rating Factors

Corporate Credit Rating
A+/Stable/A-1

Strengths:

- A low-risk monopoly gas distribution and pipeline business;
- A supportive regulatory environment with favorable cost recovery mechanisms that enhance cash flow predictability;
- A primarily residential and commercial customer base; and
- Reliable natural gas supply provided by significant storage capacity and access to three major gas supply basins.

Weaknesses:

- Investment in nonregulated operations presents construction and recontracting risks;
- The purchased gas agreement mechanism in Oregon requires the company to absorb a portion of gas costs above stated levels; and
- Interconnection with only one major pipeline, the Northwest pipeline, offset by the substantial operational flexibility at the pipeline.

Rationale

The ratings on Northwest Natural Gas Co. (NWN) reflect the company's excellent business risk profile and intermediate financial risk profile. Supportive regulation, a high-growth service area with a mostly residential customer base, reliable gas supplies provided by significant storage capacity, access to three major gas supply basins, and low operating risks characterize the utility's excellent business profile. Its interconnection with only one major pipeline somewhat moderates these strengths. We view the local gas distribution company's financial risk as having lower risks than its planned investments in nonregulated assets, which can have less stable cash flow generation, and/or recontracting risks.

The company's constructive relationship with the Oregon Public Utility Commission, which covers 90% of the customer base, has resulted in supportive rate design and incentive programs that allow exceptionally stable cash flows that are largely insulated from gas prices, weather, and usage fluctuations. Regulators recently changed the incentive sharing mechanism in NWN's purchased gas adjustment (PGA) tariff in Oregon to decrease the company's risk associated with the difference between actual gas costs and the estimated costs that are incorporated into base rates. Annually, the utility must choose to defer either 80% or 90% of the difference, which it will collect in customer rates in the subsequent year. While this reduces the company's exposure to commodity price volatility compared with the previous PGA tariff, which was set at 67%, this specific mechanism is not as supportive of credit as the mechanism in Washington that passes 100% of purchased gas costs through to ratepayers. In Oregon, conservation and weather-normalization tariffs insulate margins from a fall in delivered gas volumes due to lower customer usage levels and warmer-than-normal weather patterns during the heating season. All of these measures stabilize margins and support debt service.

NWN has undertaken a 50-50 joint-venture with Encana Oil & Gas to receive a working interest in gas reserves located in the Jonah Field in Wyoming. NWN expects that it will receive about 93 billion cubic feet (Bcf) of gas over

30 years (60% in the first 10 years) at an all-in cost of about $5.15 per dekatherm. Note the all-in cost includes an estimate for the return on investment for NWN. Since the cost of gas is recoverable through a PGA mechanism subject to the same incentive sharing mechanism that the company has in Oregon, the company is only exposed to regulatory risk. However, if the gas is extracted at a price that is higher than the market price, customers would have to bear these costs since the company is committed to supplying gas at these prices. Consequently, customers are exposed to some geological and project risk. However, the market price of gas would have to be considerably lower than $5.15 for the customer to be relatively disadvantaged. Through this transaction the company has locked in to, what amounts to, a physical hedge for about 10% of its volume demand at the above-stated price, which we think will help make it easier to predict NWN's cash flows and may also result in considerable savings for the customer.

The company's nonregulated cash flows primarily come from its Mist and Gill Ranch storage facilities, which contribute between 6% and 10% of EBITDA. Mist, in Oregon, primarily provides storage services to various utilities (60% of its capacity) operations and contributes about 90% of the nonregulated cash flows. We consider the cash flows from this asset to be fairly stable. The investment in the Gill Ranch natural gas storage facility presents incremental business and financial risks because the nonregulated investment is outside of NWN's existing service territory and is in an area with several other proposed storage projects. In addition, this type of project increases the company's exposure to market-based revenue streams. NWN has partnered with Pacific Gas and Electric Co. (25% ownership; BBB+/Stable/A-2) to develop this storage reservoir near Fresno, Calif. After construction began in January 2010, NWN's portion of the development costs went up to a range of $210 million and $220 million, an increase of almost 25%. The first phase is expected to be 20 Bcf when complete, with a possible expansion to 40 Bcf to follow. Currently, Gill Ranch has about 13 Bcf of total storage capacity. Of this, about 9.1 Bcf is in contract to various highly rated counterparties with a mix of short-, medium-, and long-term contracts. The remaining capacity is being used for optimization activities overseen by an experienced third-party.

NWN's potential investment in the Palomar East Pipeline poses less of a credit concern at this time because it will benefit from Federal Energy Regulatory Agency oversight. It will add another transmission line to NWN's service territory, thereby giving it more flexibility. It will also provide additional capacity to the region positioning NWN for future growth. There has been some progress made on the Palomar East project and the company is in active talks with potential shippers. However, NWN expects to complete the project no earlier than 2016, with the timeline subject to further revisions. A potential 106-mile expansion of the pipeline (Palomar West), providing a connection to a proposed liquefied natural gas terminal, to be developed by NorthernStar Natural Gas Inc. (not rated) on the Columbia River, has been withdrawn.

Strong cash flow metrics and high leverage relative to its current rating category characterize the company's intermediate financial risk profile. As the company works through start-up operations at Gill Ranch and funds its equity contributions to the Palomar joint venture, we expect financial ratios to weaken slightly in the near term. We also expect cash flows to be adversely affected for the coming year due to the recently signed Senate Bill 967 that requires certain utilities to reverse tax-related surcharges accrued for the 2010 and 2011 tax years. This will result in a $7.4 million one-time pretax charge to earnings. As a result, we expect funds from operations (FFO) to total debt to go down to between 17% and 19% for 2011, returning to above 20% in 2012. We expect total adjusted debt to capital for 2011 to be around 58%, coming down to around 55% over the next few years.

Liquidity

We view NWN's liquidity as adequate under our corporate liquidity methodology (see "Standard & Poor's Standardizes Liquidity Descriptors for Global Corporate Issuers," published July 2, 2010), which categorizes liquidity in five standard descriptors: exceptional, strong, adequate, less than adequate, and weak.

We expect cash uses to exceed sources by 1.4x during the next 12 months and to remain adequate for the subsequent 12 months. For liquidity sources, we expect the company to generate FFO of about $175 million. Offsetting the $250 million of availability under its revolving credit facility is about $186 million in commercial paper, resulting in a net availability of $64 million. In total, we estimate liquidity sources of more than $239 million. Projected cash uses mostly consist of capital spending, which the company expects to be around $102 million; distributions of roughly $47 million; about $10 million in debt maturities; and some minor uses related to working-capital needs and pension contributions. NWN's liquidity position benefits from its ability to absorb high-impact, low-probability events with limited need for refinancing; it has the flexibility to lower capital spending; it has solid bank relationships; it has good access to the capital markets; and it has prudent risk-management practices.

The company's debt agreements require a debt-to-capital ratio of less than 70%. At March 31, 2011, NWN was in compliance, with moderate headroom under the covenants. NWN's debt–to-total capital ratio was 55%.

Recovery analysis

We rate NWN's first mortgage bonds (FMB) 'A+', the same as the corporate credit rating, based on a recovery rating of '1' under our recovery methodology for regulated utilities. We assign recovery ratings to FMBs issued by U.S. utilities, and this can result in issue ratings being notched above the corporate credit rating on a utility, depending on the corporate credit rating category and the extent of the collateral coverage. We base the investment-grade FMB recovery methodology on the ample historical record of nearly 100% recovery for secured-bond holders in utility bankruptcies and our view that the factors that supported those recoveries (the small size of the creditor class, and the durable value of utility rate-based assets during and after a reorganization, given the essential service provided and the high replacement cost) will persist. Under our notching criteria, when assigning issue ratings to utility FMBs, we consider the limitations of FMB issuance under the utility's indenture relative to the value of the collateral pledged to bondholders, management's stated intentions on future FMB issuance, and the regulatory limitations on bond issuance. FMB ratings can exceed a utility's corporate credit rating by as much as one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories. (See "Changes To Collateral Coverage Requirements For '1+' Recovery Ratings On U.S. Utility First Mortgage Bonds," published Sept. 6, 2007.) NWN's collateral coverage of between 1x and 1.5x supports a recovery rating of '1' and an issue rating of 'A+', the same as the corporate credit rating.

Outlook

The stable outlook reflects Standard & Poor's expectation of solid consolidated financial performance, the projected mix of regulated and nonregulated activities, and steady operating performance and regulatory support. A ratings upgrade could result from a sustained improvement in financial ratios, specifically FFO to debt above 30%, and total debt to total capital below 50%. Ratings pressure could occur if the company makes significant acquisitions or investments that mostly use debt or if credit metrics deteriorate on a sustained basis, specifically FFO to debt to below 20% on a sustained basis or total debt to capital to above 55%. A downgrade could also occur if growth in the nonregulated businesses is greater than currently anticipated, unless coupled with stronger financial metrics.

Table 1

Northwest Natural Gas Co. -- Peer Comparison

Industry Sector: Gas

	Northwest Natural Gas Co.	Nicor Inc.	WGL Holdings Inc.	Piedmont Natural Gas Co. Inc.	New Jersey Natural Gas Co.
Rating as of June 21, 2011	A+/Stable/A-1	AA/Watch Neg/A-1+	A+/Stable/A-1	A/Stable/--	A/Stable/A-1
--Average of past three fiscal years--					
(Mil. $)					
Revenues	954.2	3,046.2	2,681.3	1,759.8	1,035.4
EBITDA	231.6	434.7	341.8	305.5	146.3
Net income from cont. oper.	72.4	131.1	115.6	124.9	59.4
Funds from operations (FFO)	170.8	358.4	258.6	249.8	126.7
Capital expenditures	166.2	242.3	137.0	172.3	79.3
Free operating cash flow	(26.2)	73.2	90.2	96.4	45.0
Discretionary cash flow	(68.6)	(11.6)	18.2	18.3	0.1
Cash and short-term investments	6.3	110.4	7.6	6.7	25.8
Debt	831.8	1,197.8	935.6	1,034.0	470.7
Equity	660.5	1,214.5	1,113.6	926.7	562.2
Adjusted ratios					
EBITDA margin (%)	24.3	14.3	12.7	17.4	14.1
EBITDA interest coverage (x)	5.3	8.2	7.1	5.3	6.8
EBIT interest coverage (x)	3.8	4.8	5.1	4.4	5.4
Return on capital (%)	9.9	9.1	10.4	11.1	9.6
FFO/debt (%)	20.5	29.9	27.6	24.2	26.9
Free operating cash flow/debt (%)	(3.1)	6.1	9.6	9.3	9.6
Debt/EBITDA (x)	3.6	2.8	2.7	3.4	3.2
Total debt/debt plus equity (%)	55.7	49.7	45.7	52.7	45.6

Table 2

Northwest Natural Gas Co. -- Financial Summary

Industry Sector: Gas

	--Fiscal year ended Dec. 31--				
	2010	**2009**	**2008**	**2007**	**2006**
Rating history	A+/Stable/A-1	AA-/Negative/A-1+	AA-/Negative/A-1+	AA-/Stable/A-1+	AA-/Stable/A-1+
(Mil. $)					
Revenues	812.1	1,012.7	1,037.9	1,033.2	1,013.2
EBITDA	235.5	237.4	221.8	231.3	209.5
Net income from continuing operations	72.7	75.1	69.5	74.5	63.4

Table 2

Northwest Natural Gas Co. -- Financial Summary (cont.)					
Funds from operations (FFO)	207.0	133.2	172.2	125.0	117.9
Capital expenditures	257.9	136.8	104.0	120.4	96.3
Dividends paid	44.7	42.4	40.2	38.6	38.3
Debt	944.1	765.4	785.9	629.8	628.9
Preferred stock	0.0	0.0	0.0	0.0	0.0
Equity	693.1	660.1	628.4	594.8	599.5
Debt and equity	1,637.2	1,425.5	1,414.3	1,224.5	1,228.4
Adjusted ratios					
EBITDA margin (%)	29.0	23.4	21.4	22.4	20.7
EBIT interest coverage (x)	3.8	3.8	3.8	4.0	3.4
FFO int. cov. (x)	5.4	3.7	5.3	4.1	3.7
FFO/debt (%)	21.9	17.4	21.9	19.8	18.7
Discretionary cash flow/debt (%)	(18.1)	9.8	(14.0)	3.7	1.7
Net cash flow/capex (%)	63.0	66.3	127.0	71.7	82.7
Debt/debt and equity (%)	57.7	53.7	55.6	51.4	51.2
Return on capital (%)	9.4	10.4	9.8	11.2	10.1
Return on common equity (%)	10.7	11.7	11.4	12.5	10.6
Common dividend payout ratio (un-adj.) (%)	61.4	56.5	57.8	51.8	60.4

Table 3

Reconciliation Of Northwest Natural Gas Co. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)							
	--Fiscal year ended Dec. 31, 2010--						
Northwest Natural Gas Co. reported amounts							
	Debt	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**
Reported	859.1	693.1	812.1	222.7	157.6	42.6	126.5
Standard & Poor's adjustments							
Operating leases	40.0	--	--	2.1	2.1	2.1	2.5
Postretirement benefit obligations	110.5	--	--	9.6	9.6	1.3	3.0
Share-based compensation expense	--	--	--	1.0	--	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	7.1	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--
Debt - Accrued interest not included in reported debt	5.2	--	--	--	--	--	--
Debt - Other	(70.7)	--	--	--	--	--	--
Total adjustments	85.0	0.0	0.0	12.8	18.8	3.4	5.5

Table 3

Reconciliation Of Northwest Natural Gas Co. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations
Adjusted	944.1	693.1	812.1	235.5	176.5	46.0	131.9

Related Criteria And Research

- Criteria: Key Credit Factors: Business And Financial Risks In the Investor-Owned Utilities Industry, published Nov. 26, 2008
- Key Credit Factors For U.S. Natural Gas Distributors, published Feb. 28, 2006

Ratings Detail (As Of June 29, 2011)*	
Northwest Natural Gas Co.	
Corporate Credit Rating	A+/Stable/A-1
Commercial Paper	
Local Currency	A-1
Senior Secured (22 Issues)	A+
Senior Unsecured (1 Issue)	A+
Corporate Credit Ratings History	
25-Jan-2010	A+/Stable/A-1
19-Dec-2008	AA-/Negative/A-1+
28-Feb-2006	AA-/Stable/A-1+
Business Risk Profile	Excellent
Financial Risk Profile	Intermediate

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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December 15, 2011

Piedmont Natural Gas Co. Inc.

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Table Of Contents

Piedmont Natural Gas Co. Inc.

Major Rating Factors

Corporate Credit Rating
A/Stable/NR

Strengths:

- Supportive regulatory environment.
- Low operating risk at gas-distribution utilities.
- Above-average customer growth.
- Largely residential and commercial customer base.

Weaknesses:

- A meaningful portfolio of somewhat higher-risk investments.
- Increased capital expenditure requirements at the utility segment.
- Large capital expenses associated with power generation projects.

Rationale

The rating on Charlotte, N.C.-based Piedmont Natural Gas Co. Inc. reflects an "excellent" business risk profile and "intermediate" financial risk profile (as our criteria define the terms). Piedmont's excellent business risk profile is characterized by a supportive regulatory environment, low operating risk, above-average customer growth, and a healthy service territory. Piedmont's expectations for capital expenses related to power generation projects and investments in somewhat higher-risk, unregulated operations temper the company's strengths. We expect Piedmont's regulated businesses to contribute about 85% of fiscal 2011 consolidated cash flows in the near term, in line with its recent performance.

Despite the current U.S. economy, Piedmont's service territory continues to be relatively strong, given above-average population trends and growth in the service and retail sectors. Customer growth has averaged about 1.8% during the past five years, but we expect this to moderate slightly to about 1% in the near term.

These factors should provide stable cash flow generation, which is favorable to credit quality. Piedmont distributes natural gas to more than one million customers in parts of North Carolina, South Carolina, and Tennessee. However, most of its customers (70%) and corresponding margins come from North Carolina, with the other states contributing approximately 15% each. Despite the slowdown in new housing construction, Piedmont expects customer growth to remain above national averages.

Standard & Poor's regards regulatory oversight by the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (PSCSC), and the Tennessee Regulatory Authority (TRA) as supportive of credit quality. Examples of the constructive regulatory frameworks include higher-than-average equity returns, purchased gas adjustments, and market-based rates designed to retain a large industrial load. We view North Carolina's decoupling rate mechanism as providing somewhat greater cash flow stability than the weather-normalization adjustment clauses in South Carolina and Tennessee. Although the company did not get approval for a decoupling mechanism in Tennessee, the TRA indicated that a general rate case would be the appropriate forum for this type of rate design proposal. The company has filed a general rate case with a request for incremental revenues increases of 8.9%.

Piedmont has entered into contracts with Progress Energy Inc. for building a gas supply pipeline and transporting gas to Progress' Wayne County and Sutton power plants that are converting to gas. According to the agreement, which the NCUC approved, Piedmont will build 38 miles of pipeline for the Wayne County Project and 133 miles of transmission pipeline for the Sutton project along with compression facilities for each, to provide natural gas delivery service to the plants. We expect the projects to be completed in June 2012 and June 2013 respectively. Piedmont will incur the expenses to expand the pipeline operations. The capital expenses associated with these two plants are in the $400 million to $450 million area, an increase of about $100 million from previous estimates. Though Piedmont earns on these investments under the AFUDC (Allowance for Funds Used During Construction), we consider an expansion of this magnitude to be inherently risky, due to the possibility of construction delays and cost overruns. However, the contract addresses Piedmont's prudently incurred costs. These investments take support from long-term transportation contracts and benefit from the utility's straight-fixed-variable rate design. These investments will eventually go into the rate base, with an offset for the revenue Piedmont will earn from Progress.

Piedmont's various joint ventures contribute 10% to 15% of fiscal 2011's consolidated cash flows. These include an intrastate pipeline (Cardinal), liquefied natural gas storage facilities (Hardy and Pine Needle), and natural gas marketing (SouthStar), of which Piedmont lowered its ownership to 15%. Cardinal is regulated by the NCUC and Hardy and Pine Needle is regulated by the FERC. However, SouthStar is nonregulated and we generally view it as riskier than regulated operations because of greater cash flow variability.

Based on our assumptions, over the next 12 to 24 months, we expect FFO to debt between 20% and 25% as the company raises debt to fund its expansion projects. Debt to total capital could also go up to about 55%. Cash flows could also show some volatility related to the utility segment's capital expenditures and distributions from its nonregulated investments. Pursuit of incremental investments in nonregulated ventures could increase the company's business risk profile, which would necessitate higher consolidated financial performance to maintain the rating. As of July 31, 2011, Piedmont's total debt, including capitalized operating leases and tax-effected pension and postretirement obligations, was about $958 million. Adjusted debt to capital was 48.4% and adjusted funds from operations (FFO) to debt topped 26%.

Liquidity

We consider Piedmont's liquidity as "adequate" under our corporate liquidity methodology. We expect cash uses to exceed sources by 1.3x during the next 12 months, with no significant shortages in 2013. As of July 31, 2011, the company had about $371 of availability under its $650 million revolving credit facility. However, this amount could fluctuate significantly depending on the company's needs. We expect that the company will generate FFO of roughly $250 million over the next 12 months. However, this could be subject to substantial swings based on working-capital changes, mainly because of natural gas usage levels, natural gas in storage, and swings in commodity prices.

We estimate liquidity uses of about $450 million over the next 12 months. We project cash uses will mostly consist of maintenance capital expenditures--which we expect to be about $200 million--distributions of roughly $85 million, working-capital needs of more than $100 million, and pension contributions and share repurchases of about $20 million.

The company's debt agreements require a debt to capital ratio of less than 70%. As of July 31, 2010, Piedmont was comfortably in compliance, with a 50% ratio.

Outlook

The stable outlook on Piedmont reflects our expectation that financial measures will continue to remain appropriate for the current rating, with support from the company's pursuit of additional regulatory cost-recovery mechanisms and its primary focus on its regulated businesses. We could raise the rating if the investments in unregulated businesses decline and regulators grant additional cost-recovery mechanisms that result in FFO to total debt of above 25% on a sustained basis. Conversely, we could lower the rating if Piedmont increases the size of its unregulated portfolio or if we feel additional capital expenses won't be recoverable due to construction delays on the power generation projects, such that financial metrics deteriorate–specifically if FFO to total debt stays below 20%.

Table 1

Piedmont Natural Gas Co. Inc.--Peer Comparison

Industry Sector: Gas

	Piedmont Natural Gas Co. Inc.	AGL Resources Inc.	The Laclede Group Inc.	Vectren Corp.	Washington Gas Light Co.
Rating as of Dec. 15, 2011	A/Stable/--	A-/Watch Neg/A-2	A/Stable/--	A-/Stable/--	A+/Stable/A-1
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	1,759.8	2,496.7	1,744.5	2,234.4	1,372.0
EBITDA	305.5	658.0	161.0	511.6	312.5
Net income from cont. oper.	124.9	224.3	60.7	131.9	92.8
Funds from operations (FFO)	249.8	505.3	132.4	447.9	266.6
Capital expenditures	172.3	450.3	61.8	365.0	148.3
Free operating cash flow	96.4	24.3	111.6	65.2	156.6
Discretionary cash flow	18.3	(119.3)	76.7	(42 1)	84.3
Cash and short-term investments	6.7	22.0	68.3	38.5	3.6
Debt	1,034.0	2,537.7	541.7	1,976.2	947.9
Equity	926.7	1,779.7	542.0	1,412.5	997.9
Adjusted ratios					
EBITDA margin (%)	17.4	26.4	9.2	22.9	22.8
EBITDA interest coverage (x)	5.3	5.4	5.2	4.8	6.5
EBIT interest coverage (x)	4.4	4.1	3.9	3.0	4.5
Return on capital (%)	11.1	10.2	9.0	8.4	9.3
FFO/debt (%)	24.2	19.9	24.4	22.7	28.1
Free operating cash flow/debt (%)	9.3	1.0	20.6	3.3	16.5
Debt/EBITDA (x)	3.4	3.9	3.4	3.9	3.0
Total debt/debt plus equity (%)	52.7	58.8	50.0	58.3	48.7

Table 2

Piedmont Natural Gas Co. Inc.--Financial Summary

Industry Sector: Gas

	--Fiscal year ended Oct. 31--				
	2010	**2009**	**2008**	**2007**	**2006**
Rating history	A/Stable/--	A/Stable/--	A/Stable/--	A/Stable/--	A/Stable/--
(Mil. $)					
Revenues	1,552.3	1,638.1	2,089.1	1,711.3	1,924.6
EBITDA	294.9	315.4	306.0	279.6	272.4
Net income from cont. oper.	142.0	122.8	110.0	104.4	97.2
Funds from operations (FFO)	242.8	266.8	239.7	202.2	226.8
Capital expenditures	199.1	131.7	186.3	135.2	200.2
Dividends paid	80.3	78.4	75.5	73.6	72.1
Debt	926.0	1,075.9	1,100.3	946.7	941.8
Preferred stock	0.0	0.0	0.0	0.0	0.0
Equity	964.9	927.9	887.2	878.4	855.5
Debt and equity	1,890.9	2,003.8	1,987.5	1,825.0	1,797.3
Adjusted ratios					
EBITDA margin (%)	19.0	19.3	14.6	16.3	14.2
EBIT interest coverage (x)	4.9	4.9	3.7	3.6	3.7
FFO int. cov. (x)	5.5	6.4	4.6	4.2	4.8
FFO/debt (%)	26.2	24.8	21.8	21.4	24.1
Discretionary cash flow/debt (%)	9.7	14.1	(16.9)	3.4	(17.2)
Net Cash Flow / Capex (%)	81.7	143.1	88.1	95.1	77.3
Debt/debt and equity (%)	49.0	53.7	55.4	51.9	52.4
Return on capital (%)	11.7	10.7	11.0	11.1	11.1
Return on common equity (%)	13.9	13.3	12.0	11.4	10.6
Common dividend payout ratio (un-adj.) (%)	56.5	63.8	68.6	70.5	74.2

Table 3

Reconciliation Of Piedmont Natural Gas Co. Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

	--Fiscal year ended Oct. 31, 2010--							
Piedmont Natural Gas Co. Inc. reported amounts								
	Debt	**Shareholders' equity**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Capital expenditures**
Reported	973.9	964.9	298.9	200.4	43.7	360.5	360.5	209.0
Standard & Poor's adjustments								
Operating leases	18.5	--	1.1	1.1	1.1	3.7	3.7	--
Postretirement benefit obligations	--	--	(6.4)	(6.4)	--	14.8	14.8	--
Capitalized interest	--	--	--	--	10.0	(10.0)	(10.0)	(10.0)
Asset retirement obligations	15.1	--	1.4	1.4	1.4	(0.2)	(0.2)	--

Table 3

Reconciliation Of Piedmont Natural Gas Co. Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)								
Reclassification of nonoperating income (expenses)	--	--	--	78.5	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	(126.0)	--
Debt - Accrued interest not included in reported debt	20.1	--	--	--	--	--	--	--
Debt - Other	(101.7)	--	--	--	--	--	--	--
Total adjustments	(48.0)	0.0	(3.9)	74.6	12.4	8.3	(117.7)	(10.0)

Standard & Poor's adjusted amounts

	Debt	Equity	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Capital expenditures
Adjusted	926.0	964.9	294.9	275.0	56.1	368.8	242.8	199.1

Related Criteria And Research

- Criteria: Key Credit Factors: Business And Financial Risks In the Investor-Owned Utilities Industry, Nov. 26, 2008
- Key Credit Factors For U.S. Natural Gas Distributors, Feb. 28, 2006

Ratings Detail (As Of December 15, 2011)	
Piedmont Natural Gas Co. Inc.	
Corporate Credit Rating	A/Stable/NR
Senior Unsecured (7 Issues)	A
Corporate Credit Ratings History	
13-Apr-2004	A/Stable/NR
22-Jul-2003	A/Negative/A-1
17-Oct-2002	A/Watch Neg/--
Business Risk Profile	Excellent
Financial Risk Profile	Intermediate

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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September 28, 2011

Southern Co.

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Table Of Contents

Southern Co.

Major Rating Factors

Corporate Credit Rating
A/Stable/A-1

Strengths:
- Stable cash flows;
- Operations under generally constructive regulatory environments;
- A large and diverse customer base;
- Regulatory and geographic diversity; and
- Conservative financial risk management practices.

Weaknesses:
- Increased business risk with the construction of new nuclear and integrated gasification combined-cycle plants; and
- A significant capital spending program.

Rationale

The ratings on Atlanta-based utility holding company Southern Co. reflect the consolidated credit profiles of its operating subsidiaries Alabama Power Co., Georgia Power Co., Gulf Power Co., and Mississippi Power Co. Standard & Poor's Ratings Services views Southern Power Co., Southern's other major subsidiary, as an equity investment and does not incorporate it into the assessment of Southern's credit quality.

Southern has an excellent consolidated business risk profile characterized by stable regulated electric utility operations in Georgia, Alabama, Mississippi, and Florida, which contribute more than 90% of consolidated operating income. The business risk profile benefits from operations in jurisdictions with generally constructive regulatory frameworks, combined with effective management of regulatory relations; strong operating performance and high availability and capacity utilization factors for owned generation; regulatory and operating diversity with a presence in four states; competitive rates for the region that provide some cushion for future rate increases to recover fuel costs and increasing capital expenditures; lack of meaningful unregulated operations; and prudent and reasonably conservative management and financial policies. (For more on business risk and financial risk, see "Business Risk/Financial Risk Matrix Expanded," published May 27, 2009, on RatingsDirect on the Global Credit Portal.)

These strengths are offset primarily by significant capital spending needs of about $13.2 billion during 2011-2013 (excluding Southern Power). The expenditures are to address significant environmental-compliance requirements, transmission and distribution system growth needs, new generation projects (including nuclear), system maintenance, and nuclear fuel expenditures. Capital expenditures may increase depending on the level and compliance timeframe for new environmental rules under development by the Environmental Protection Agency. Southern estimates that depending on the nature of the final rules, such expenditures may total an additional $700 million to $2.9 billion over the next three years for potential environmental controls, replacement generation capacity, and transmission upgrades. Timely recovery of these expenditures is necessary to provide ongoing support to the consolidated credit profile, although this may be challenging given the still-modest economic recovery in the regional and national economies.

The planned capital spending program includes amounts for building two new nuclear plants at an existing Georgia Power site. We expect that major plant-specific construction will start once the company receives the combined construction and operating license from the Nuclear Regulatory Commission in late 2011 or early 2012. Georgia Power will own 45.7% of each of the two 1,117-megawatt (MW) units. The Georgia Public Service Commission (GPSC) certified construction of the two units in April 2009 at an in-service cost for Georgia Power's share of the project (including escalation and financing costs) of about $6.1 billion. We expect the first unit to enter commercial operation in 2016 and the second in 2017. The regulatory framework in Georgia supports construction of new-generation assets through the combination of the Integrated Resource Plan approach and a plant certification process, which ensure recovery of prudently incurred investments in base rates upon timely and on-budget completion. In addition, legislation was passed in Georgia that allows for recovery of a cash return on construction work in progress during the construction period starting in 2011, providing incremental credit support for large capital spending projects and moderating the rate impact of including the new plant in the rate base upon commercial operation. The ability to collect about $1.68 billion in financing costs during the construction period reduces the in-service cost of the new plants to about $4.4 billion. On Dec. 21, 2010, the GPSC approved Georgia Power's Nuclear Construction Cost Recovery tariff, effective Jan. 1, 2011, which allows recovery of about $223 million during the year of financing costs associated with the nuclear plant construction.

Given the new technology and long construction period, the construction of the new nuclear units contributes to an increase business risk, placing pressure on the consolidated business risk profile, and necessitating completion of the project on budget and on schedule to mitigate adverse effects on credit quality. In early 2010, Georgia Power amended the engineering, procurement, and construction contract with Westinghouse and Stone & Webster to replace certain index-based adjustments to the purchase price with fixed escalation amounts, thereby increasing cost certainty. The GPSC approved the amendment in August 2010.

Southern is also pursuing the construction of a 582-MW integrated gasification combined-cycle unit (Kemper IGCC) at Mississippi Power at a certified cost of $2.4 billion. Mississippi Power has submitted a filing with the Mississippi Public Service Commission to begin recovering financing costs during the construction period, starting in 2012 and ending in 2014. Similar to the nuclear plant construction, the Kemper IGCC unit is being built under a generally constructive regulatory framework. Importantly, we expect that a significant portion of the costs for the construction will be known or fixed early in the construction process, mitigating the price risk of the project. Nevertheless, the lack of recent construction experience for similar types of plants in the U.S. contributes to an increase in business risk.

Southern's consolidated deferred fuel balance totaled about $309 million as of June 30, 2011, a reduction of about $210 million compared to June 30, 2010. Georgia Power was the largest contributor to this deferral with about $321 million. The GPSC approved a mechanism that allows for fuel costs to adjust intra-year if fuel cost underrecovery exceeds the budget by more than $75 million, preventing further material accumulation. Although the regulatory environment has historically been generally constructive, the large capital spending program combined with the deferred fuel-cost recovery may pressure the company's competitive rates and regulatory relationships, especially given the still-slow recovery in the regional economy.

Southern's consistent cash flow generation and generally conservative financial risk management policies support the company's overall intermediate financial risk profile, and benefit from the preponderance of regulated utility operations. For the 12 months ended June 30, 2011, adjusted funds from operations (FFO) was about $4.9 billion, while total adjusted debt was $22 billion, leading to adjusted FFO interest coverage of 5.6x, adjusted FFO to debt of

22%, and adjusted total debt to total capital of 55.4%. Adjusted FFO benefits from incremental recovery of fuel costs, as well as the completion of various projects included in the rate base. The most recent credit metrics reflect about $870 million in off-balance-sheet debt stemming from the shortfall in the current funding level of pension and other postretirement obligations; this debt also includes about $412 million of trust-preferred securities and $1.08 billion of preferred and preference shares that we view as having intermediate equity content.

Liquidity

The short-term rating on Southern is 'A-1'. The company has adequate liquidity that can more than cover its needs for the next 12 months even if EBITDA declines by 20%. (For more on liquidity, see "Standard & Poor's Standardizes Liquidity Descriptors For Global Corporate Issuers," published July 2, 2010.)

We base our liquidity assessment on the following factors and assumptions:

- We expect the company's liquidity sources (including cash, FFO, and credit facility availability) over the next 12 months to exceed uses by more than 1.2x.
- Debt maturities for 2011 and 2012 are modest.
- Even if EBITDA declines by 20%, we believe that net sources of cash will still exceed net uses.
- The company has good relationships with its banks, in our assessment, and has a good standing in the capital markets, having successfully issued debt over the past few years, including during the credit crisis. Furthermore, Southern has the ability to absorb high-impact, low-probability events with limited refinancing.

In our analysis, we assumed liquidity of $9.5 billion over the next 12 months, consisting of cash, FFO, and availability under the revolving credit facilities. We estimate the company will use about $6.2 billion during the same period, for capital spending, debt maturities, working capital needs, and shareholder dividends.

Southern has manageable debt maturities for 2011 and 2012 and a larger maturity of $1.7 billion in 2013. As of June 30, 2011, the revolving credit facilities totaled $4.7 billion, with about $4 billion still available. More than $4 billion of the available credit facilities mature in 2013 and beyond. The company also had $437 million of cash on hand.

Outlook

We base the stable outlook on Southern and its affiliates on the company's consistent, regulated electric utility operations, which benefit from constructive regulatory frameworks, strong operations, a large service territory with attractive demographics, and proactive and generally conservative management and financial risk practices. In addition, the stable outlook anticipates that Southern will continue to proactively manage its liquidity position to ensure adequate liquidity over the intermediate term, especially as capital spending increases. Currently, we don't contemplate a higher rating, but such a change would largely depend on a consistently stronger financial risk profile.

We would lower the ratings on Southern and its subsidiaries if the consolidated financial risk profile weakens over the next few years such that debt leverage becomes aggressive, adjusted FFO to total debt is consistently below 18%, and adjusted FFO interest coverage declines to below 4x as a result of the substantial capital spending program and the inability to recover such expenses in rates in a timely manner. The construction of the new nuclear plants in Georgia along with the new integrated gasification combined-cycle unit in Mississippi, both of which we expect Southern will fund in a balanced manner, places additional pressure on the consolidated ratings, such that any delays in the construction schedules, cost overruns on the budgets, or indications of weakening regulatory support that protracts or prevents recovery of the invested capital would also lead to lower ratings.

Financial Risk Profile

Accounting

Southern's financial statements are prepared in accordance with the accounting principles generally accepted in the U.S. and are audited by Deloitte & Touche, which has issued unqualified opinions on the company's financial statements and internal controls for 2010.

In assessing the financial risk profile of Southern, Standard & Poor's views Southern Power as an equity investment and its dividend distributions to Southern as part of FFO for computing coverage ratios. We view Southern Power's equity as minority interest for capitalization ratios.

Southern reports changes in underrecovered fuel balances as part of changes in working capital. However, in analyzing the company's cash flows, Standard & Poor's reclassifies these changes as part of changes in FFO. This adjustment reflects the long-term nature of recovery of fuel costs, which is a more standard measure of FFO than working capital.

Because of Southern's current funding level of pension and other postretirement obligations, we impute $870 million as an off-balance-sheet obligation.

Standard & Poor's views Southern's $412 million of trust-preferred securities and $1.1 billion of preferred and preference shares as of Dec. 31, 2010, as having intermediate equity content, ascribing 50% of each amount to debt and 50% to equity for ratio computation purposes. We treat the associated distributions similarly as 50% interest and 50% dividends.

Capitalization of non-rail-car operating leases adds about $212 million of off-balance-sheet obligations as of Dec. 31, 2010, while debt imputed for purchased power agreements adds about $1.1 billion. We include purchased power agreements with Southern Power in imputed debt because we rate Southern Power on a stand-alone basis.

Table 1

Southern Co. -- Peer Comparison

Industry Sector: Electric

	Southern Co.	Duke Energy Corp.	Dominion Resources Inc.	American Electric Power Co. Inc.	Xcel Energy Inc.
Rating as of Sept. 28, 2011	A/Stable/A-1	A-/Stable/A-2	A-/Stable/A-2	BBB/Stable/A-2	A-/Stable/A-2
	--Average of the past three fiscal years--				
(Mil. $)					
Revenues	15,645.6	13,403.3	15,539.3	13,871.7	10,385.6
EBITDA	4,921.6	4,474.4	4,572.3	4,190.0	2,524.8
Net income from continuing operations	1,664.9	1,219.7	2,028.7	1,314.7	694.4
Funds from operations (FFO)	3,955.5	3,985.8	3,160.3	3,256.9	2,004.8
Capital expenditures	4,191.1	4,530.2	3,568.4	3,182.0	2,052.6
Free operating cash flow	(596.1)	(549.7)	(571.1)	(568.1)	(67.7)
Dividends paid	1,402.8	1,232.7	1,067.7	762.6	422.9

Table 1

Southern Co. -- Peer Comparison (cont.)					
Discretionary cash flow	(1,998.8)	(1,782.4)	(1,638.8)	(1,330.7)	(490.5)
Cash and short-term investments	498.9	1,416.3	58.7	767.0	155.1
Debt	21,358.2	18,503.2	18,353.2	20,743.2	10,963.4
Preferred stock	747.0	0.0	887.5	187.8	252.5
Equity	15,532.3	21,896.7	12,034.3	12,672.8	7,696.0
Debt and equity	36,890.6	40,399.9	30,387.5	33,416.0	18,659.4
Adjusted ratios					
EBITDA margin (%)	31.5	33.4	29.4	30.2	24.3
EBIT interest coverage (x)	3.3	3.2	3.4	2.5	2.7
Return on capital (%)	8.3	6.8	10.5	7.7	8.0
FFO interest coverage (X)	4.5	5.1	4.0	3.5	4.1
FFO/debt (%)	18.5	21.5	17.2	15.7	18.3
Free operating cash flow/debt (%)	(2.8)	(3.0)	(3.1)	(2.7)	(0.6)
Discretionary cash flow/debt (%)	(9.4)	(9.6)	(8.9)	(6.4)	(4.5)
Net cash flow/capital expenditures (%)	60.9	60.8	58.6	78.4	77.1
Debt/EBITDA (x)	4.3	4.1	4.0	5.0	4.3
Total debt/debt plus equity (%)	57.9	45.8	60.4	62.1	58.8
Return on capital (%)	8.3	6.8	10.5	7.7	8.0
Return on common equity (%)	10.4	4.3	18.0	9.9	8.2
Common dividend payout ratio (unadjusted) (%)	86.4	99.7	50.2	56.8	64.2

Table 2

Southern Co. -- Financial Summary					
Industry Sector: Electric					
	--Fiscal year ended Dec. 31--				
	2010	**2009**	**2008**	**2007**	**2006**
Rating history	A/Stable/A-1	A/Stable/A-1	A/Stable/A-1	A/Stable/A-1	A/Stable/A-1
(Mil. $)					
Revenues	16,326.9	14,796.3	15,813.5	14,381.0	13,579.0
EBITDA	5,145.0	4,807.6	4,812.3	4,415.0	4,211.4
Net income from continuing operations	1,910.0	1,487.1	1,597.6	1,602.4	1,449.5
Funds from operations (FFO)	4,419.5	3,973.5	3,473.6	3,207 8	3,412.6
Capital expenditures	3,925.9	4,606.9	4,040.7	3,465.7	2,620.3
Dividends paid	1,538.0	1,411.0	1,259.2	1,197.1	1,184.0
Debt	21,998.7	21,918.0	20,158.0	16,754.9	15,490.4
Preferred stock	747.0	747.0	747.0	746.0	1,152.5
Equity	16,949.0	15,625.0	14,023.0	13,131.0	12,523.5
Debt and equity	38,947.7	37,543.0	34,181 0	29,885 9	28,013 9
Adjusted ratios					
EBITDA margin (%)	31.5	32.5	30.4	30.7	31.0

Table 2

Southern Co. -- Financial Summary (cont.)					
EBIT interest coverage (x)	3.6	3.2	3.3	3.4	3.9
FFO interest coverage (x)	4.9	4.4	4.2	4.3	5.6
FFO/debt (%)	20.1	18.1	17.2	19.1	22.0
Discretionary cash flow/debt (%)	(5.4)	(13.2)	(9.5)	(8.0)	(5.6)
Net cash flow/capital expenditures (%)	73.4	55.6	54.8	58.0	85.1
Debt/debt and equity (%)	56.5	58.4	59.0	56.1	55.3
Return on capital (%)	8.3	8.1	8.6	9.1	8.6
Return on common equity (%)	11.0	8.8	11.2	12.9	13.3
Common dividend payout ratio (unadjusted) (%)	81.1	96.3	83.5	77.5	75.0

Table 3

Reconciliation Of Southern Co. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

--Fiscal year ended Dec. 31, 2010--

Southern Co. reported amounts	Debt	Shareholders' equity	Revenues	EBITDA	Operating income	Interest expense	Cash flow from operations	Cash flow from operations	Dividends paid	Capital expenditures
Reported	19,250.2	16,051.9	16,326.9	4,912.7	3,518.7	818.9	3,771.0	3,771.0	1,561.0	3,786.4
Standard & Poor's adjustments										
Operating leases	211.9	--	--	10.5	10.5	10.5	65.9	65.9	--	44.4
Intermediate hybrids reported as debt	(206.0)	206.0	--	--	--	(9.5)	9.5	9.5	9.5	--
Intermediate hybrids reported as equity	541.0	(541.0)	--	--	--	32.5	(32.5)	(32.5)	(32.5)	--
Postretirement benefit obligations	870.4	--	--	(61.0)	(61.0)	--	418.0	418.0	--	--
Capitalized interest	--	--	--	--	--	73.9	(73.9)	(73.9)	--	(73.9)
Share-based compensation expense	--	--	--	33.0	--	--	--	--	--	--
Power purchase agreements	1,136.2	--	--	171.8	53.8	53.8	118.0	118.0	--	118.0
Asset retirement obligations	--	--	--	78.0	78.0	78.0	(40.3)	(40.3)	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	159.4	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	137.8	--	--
Minority interests	--	1,232.1	--	--	--	--	--	--	--	--

Table 3

Reconciliation Of Southern Co. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)										
U.S. decommissioning fund contributions	--	--	--	--	--	--	(5.0)	(5.0)	--	--
Debt -- accrued interest not included in reported debt	195.0	--	--	--	--	--	--	--	--	--
FFO -- other	--	--	--	--	--	--	51.0	51.0	--	--
Capital expenditures -- other	--	--	--	--	--	--	--	--	--	51.0
Total adjustments	2,748.4	897.1	--	232.3	240.7	239.2	510.7	648.5	(23.0)	139.5

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	21,998.7	16,949.0	16,326.9	5,145.0	3,759.4	1,058.1	4,281.7	4,419.5	1,538.0	3,925.9

Related Criteria And Research

- Standard & Poor's Standardizes Liquidity Descriptors for Global Corporate Issuers, July 2, 2010
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Analytical Methodology, April 15, 2008

Ratings Detail (As Of September 28, 2011)	
Southern Co.	
Corporate Credit Rating	A/Stable/A-1
Commercial Paper	
Local Currency	A-1
Preferred Stock (2 Issues)	BBB+
Senior Unsecured (5 Issues)	A
Corporate Credit Ratings History	
21-Dec-2000	A/Stable/A-1
30-Nov-1998	A/Watch Neg/A-1
24-Jan-1997	A/Stable/A-1
Business Risk Profile	Excellent
Financial Risk Profile	Intermediate
Related Entities	
Alabama Power Capital Trust V	
Preferred Stock (1 Issue)	BBB+
Alabama Power Co.	
Issuer Credit Rating	A/Stable/A-1
Commercial Paper	
Local Currency	A-1

Ratings Detail (As Of September 28, 2011) (cont.)	
Preference Stock (2 Issues)	BBB+
Preferred Stock (4 Issues)	BBB+
Senior Secured (6 Issues)	A/A-1
Senior Unsecured (28 Issues)	A
Senior Unsecured (22 Issues)	A/A-1
Georgia Power Co.	
Issuer Credit Rating	A/Stable/A-1
Preference Stock (1 Issue)	BBB+
Preferred Stock (2 Issues)	BBB+
Senior Unsecured (47 Issues)	A
Senior Unsecured (1 Issue)	A-
Senior Unsecured (31 Issues)	A/A-1
Senior Unsecured (7 Issues)	A/NR
Gulf Power Co.	
Issuer Credit Rating	A/Stable/A-1
Preference Stock (2 Issues)	BBB+
Preferred Stock (3 Issues)	BBB+
Senior Unsecured (16 Issues)	A
Senior Unsecured (2 Issues)	A/A-1
Senior Unsecured (1 Issue)	A/NR
Mississippi Power Co.	
Issuer Credit Rating	A/Stable/A-1
Preferred Stock (4 Issues)	BBB+
Senior Secured (1 Issue)	A+/A-1
Senior Unsecured (7 Issues)	A
Senior Unsecured (4 Issues)	A/A-1
Southern Company Capital Funding Inc.	
Senior Unsecured (1 Issue)	A-
Southern Company Funding Corp.	
Issuer Credit Rating	--/--/A-1
Commercial Paper	
Local Currency	A-1
Southern Co. Services Inc.	
Issuer Credit Rating	A/Stable/--
Southern Electric Generating Co.	
Issuer Credit Rating	A/Stable/NR
Senior Unsecured (1 Issue)	A
Southern Power Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured (4 Issues)	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

STANDARD & POOR'S

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September 28, 2011

Vectren Corp.

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Table Of Contents

Vectren Corp.

Major Rating Factors

Corporate Credit Rating
A-/Stable/--

Strengths:

- A low-risk monopoly position as a natural gas and electricity distribution utility,
- Supportive regulatory environments, and
- A large, stable residential and commercial customer base.

Weaknesses:

- A significant financial risk profile, characterized by high financial leverage and weak cash flow measures, and
- Nonregulated operations--particularly coal mining and energy marketing--that add some cash flow volatility.

Rationale

Standard & Poor's Ratings Services bases its ratings on Vectren Corp.'s consolidated credit profile, which we deem to have an excellent business risk profile and a significant financial risk profile. (See "Business Risk/Financial Risk Matrix Expanded," published May 27, 2009, on RatingsDirect on the Global Credit Portal.) Vectren's operations are split between its regulated businesses (roughly 85% of EBITDA) and its various nonregulated business (15%). We expect that the percentage contribution of the nonregulated businesses will increase, but that the utility will continue to generate the lion's share of Vectren's cash flow.

The stability of Vectren's utility operations underpins the company's ratings. Even when economic growth is weak and commodity prices are volatile, the utilities tend to generate stable cash flows due to supportive regulation and lack of competition. Through its intermediate holding company, Vectren Utility Holdings Inc. (VUHI; A-/Stable/A-2), Vectren serves about 1 million natural gas customers in Indiana and Ohio and another 142,000 electricity customers in Indiana through its three operating subsidiaries: Indiana Gas Co. Inc. (A-/Stable/--), Southern Indiana Gas & Electric Co. (SIGECO; A-/Stable/--), and Vectren Energy Delivery of Ohio Inc. (not rated).

The regulated rate structure enables the utilities to generate consistent earnings, regardless of natural gas and power prices, by allowing the utilities to pass on the costs to ratepayers via purchased gas adjustment clauses and other such mechanisms. Regulation permits the utilities to earn a return on equity in the 10% area, although actual returns often fall short of the allowed returns between rate cases. VUHI also benefits from several other regulatory mechanisms, such as decoupling, weather-normalization clauses, and accelerated recovery of certain regulatory and transmission investments. These investments further mitigate potential cash flow volatility and reduce regulatory lag. Still, weather can affect VUHI's earnings in its electricity distribution business, for which does not have a weather-normalization clause.

Vectren houses its more volatile nonregulated businesses under its Vectren Enterprises Inc. subsidiary. They consist of:

- Coal mining: Vectren owns and operates three underground mines and one surface mine, all in the Illinois basin. It sells the coal to Vectren's utilities and to third parties. Vectren expects to sell over 5 million tons in 2011, with the vast majority fixed at previously contracted prices. We view Vectren's coal mining operations as inherently risky due to mines' high fixed costs and challenging working conditions, as well as potentially volatile coal prices.

- Energy marketing: Via its 61%-owned ProLiance and 100%-owned Vectren Source subsidiaries, Vectren markets natural gas to residential, commercial, and utility clients, and engages in various arbitrage and optimization-trading activities to profit from market price dislocations. In 2010 and year-to-date 2011, this unit has underperformed, with ProLiance incurring a net loss, due to limited trading opportunities coupled with fixed costs related to various transportation contracts. We expect business conditions to remain challenging in 2011 and probably 2012, and generally discount the cash flow contribution related to the more volatile trading operations.
- Infrastructure services: Via its wholly owned subsidiaries Miller Pipeline LLC and the newly acquired Minnesota Limited Inc., Vectren provides underground construction and repair to utility infrastructure, such as gas pipelines. Business prospects are now strong, as evidenced by a healthy backlog as of June 30, 2011. However, infrastructure spending is cyclical and the business is competitive.
- Energy services: Vectren assists various institutions in reducing energy costs by upgrading their facilities with energy-efficient equipment. It also builds and operates renewable energy projects. While this is not a capital-intensive business, cash flows can be volatile, depending on project backlog.

Vectren had about $2 billion of adjusted debt as of June 30, 2011, flat from year-end. As of year-end 2010, the debt consisted of:

- $919 million of unsecured notes at VUHI.
- $269 million of secured first mortgage bonds at SIGECO.
- $121 million of unsecured notes at Indiana Gas.
- $410 million of unsecured notes at Vectren Capital Corp. The company issued these bonds to fund the nonregulated operations, and Vectren guarantees them.
- $121 million of debt adjustments, primarily related to underfunded pension and postretirement obligations and asset retirement obligations. We also lower short-term borrowings related to natural gas inventory purchases at the utility level.

On a consolidated basis, Vectren's funds from operations (FFO) to debt stood at 24% as of June 30, 2011, although this ratio was somewhat inflated due to bonus depreciation, which led to lower cash taxes. Debt to capital was 58%.

We forecast Vectren's ratios to remain relatively flat, with FFO to debt in the 22%-24% range in coming years. We assume that the utilities will generate stable cash flow, and that the company will see moderate growth in its infrastructure services and coal mining segments. We expect that the utility's contribution to overall EBITDA will fall from the current 85% but remain at about 75% over the next few years.

Liquidity

We judge Vectren's liquidity to be adequate, with anticipated cash sources exceeding uses by roughly 1.5x over the next 12 months. (See "Standard & Poor's Standardizes Liquidity Descriptors For Global Corporate Issuers," published July 2, 2010.)

Cash sources consist mainly of expected FFO in the $475 million area and availability under the committed bank lines, which totaled $455 million as of June 30, 2011. The company maintains $600 million of revolving credit capacity, with $350 million being available for the utility group and $250 million for the nonregulated operations. The facilities mature in December 2013. Vectren was comfortably in compliance with all financial covenants as of second-quarter's end.

Expected cash uses consist of capital spending in the $300 million area, $115 million of common dividends, and approximately $140 million of debt maturities over the next 12 months. Vectren also faces seasonal working capital needs in the gas utility business and must occasionally post collateral related to derivative transactions in its nonregulated marketing businesses. Collectively, these cash requirements have been under $50 million in recent years, although they could grow larger if natural gas prices increase.

Outlook

The stable outlook reflects our expectation that Vectren will continue to generate the lion's share of its cash flow from regulated businesses and maintain FFO to debt in the 20%-25% range. We do not anticipate a positive ratings action in the near future. The company would need to consistently generate FFO to debt in the high 20% area for us to consider revising the outlook to positive or raising the ratings. We could lower ratings if FFO to debt declines to under 20%, or if the more volatile nonregulated businesses become a more meaningful percentage of the overall company and the company does not rein in leverage metrics.

Related Criteria And Research

- Standard & Poor's Standardizes Liquidity Descriptors For Global Corporate Issuers, July 2, 2010
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009

Table 1

Vectren Corp. -- Peer Comparison

Industry Sector: Combo

	Vectren Corp.	AGL Resources Inc.	Atmos Energy Corp.	Piedmont Natural Gas Co. Inc.	The Laclede Group Inc.
Rating as of Sept. 28, 2011	A-/Stable/--	A-/Watch Neg/A-2	BBB+/Stable/A-2	A/Stable/--	A/Stable/--
	--Average of the past three fiscal years--				
(Mil. $)					
Revenues	2,234.4	2,496.7	5,660.0	1,759.8	1,946.4
EBITDA	511.6	658.0	711.3	305.5	153.9
Net income from continuing operations	131.9	224.3	192.4	124.9	58.6
Funds from operations (FFO)	447.9	505.3	570.8	249.8	122.4
Capital expenditures	365.0	450.3	522.3	172.3	57.9
Free operating cash flow	65.2	24.3	143.5	96.4	53.2
Discretionary cash flow	(42.1)	(119.3)	22.5	18.3	19.5
Cash and short-term investments	38.5	22.0	96.6	6.7	58.8
Debt	1,976.2	2,537.7	2,489.3	1,034.0	551.0
Equity	1,412.5	1,779.7	2,135.9	926.7	513.2
Adjusted ratios					
EBITDA margin (%)	22.9	26.4	12.6	17.4	7.9
EBITDA interest coverage (x)	4.8	5.4	4.1	5.3	4.8

Table 1

Vectren Corp. -- Peer Comparison (cont.)					
EBIT interest coverage (x)	3.0	4.1	2.8	4.4	3.6
Return on capital (%)	8.4	10.2	9.5	11.1	9.0
FFO/debt (%)	22.7	19.9	22.9	24.2	22.2
Free operating cash flow/debt (%)	3.3	1.0	5.8	9.3	9.6
Debt/EBITDA (x)	3.9	3.9	3.5	3.4	3.6
Total debt/debt plus equity (%)	58.3	58.8	53.8	52.7	51.8

Table 2

Vectren Corp. -- Financial Summary					
Industry Sector: Combo					
	--Fiscal year ended Dec. 31--				
	2010	**2009**	**2008**	**2007**	**2006**
Rating history	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--
(Mil. $)					
Revenues	2,129.5	2,088.9	2,484.7	2,281.9	2,041.6
EBITDA	559.1	505.6	470.1	456.8	405.5
Net income from continuing operations	133.7	133.1	129.0	143.1	108.8
Funds from operations (FFO)	497.9	423.1	422.6	327.0	296.4
Capital expenditures	277.6	426.0	391.3	331.2	285.1
Dividends paid	110.8	108.6	102.6	96.4	93.1
Debt	1,955.6	1,978.9	1,994.1	1,828.7	1,760.6
Preferred stock	0.0	0.0	0.0	0.0	0.0
Equity	1,451.3	1,410.9	1,375.4	1,281.6	1,226.0
Debt and equity	3,406.8	3,389.7	3,369.5	3,110.2	2,986.6
Adjusted ratios					
EBITDA margin (%)	26.3	24.2	18.9	20.0	19.9
EBITDA interest coverage (x)	5.0	4.8	4.6	4.3	4.0
EBIT interest coverage (x)	2.9	2.9	3.1	3.0	2.4
FFO interest coverage (x)	5.4	5.0	5.1	4.0	3.8
FFO/debt (%)	25.5	21.4	21.2	17.9	16.8
Discretionary cash flow/debt (%)	0.2	(3.4)	(3.1)	(7.0)	(3.7)
Net cash flow/capital expenditures (%)	139.5	73.8	81.8	69.6	71.3
Debt/EBITDA (x)	3.5	3.9	4.2	4.0	4.3
Debt/debt and equity (%)	57.4	58.4	59.2	58.8	59.0
Return on capital (%)	8.4	7.9	8.7	9.7	7.7
Return on common equity (%)	9.2	9.2	9.5	11.4	8.9
Common dividend payout ratio (unadjusted) (%)	82.9	81.6	79.5	67.4	85.6

Table 3

Reconciliation Of Vectren Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

--Fiscal year ended Dec. 31, 2010--

Vectren Corp. reported amounts

	Debt	Shareholders' equity	Revenues	EBITDA	Operating income	Interest expense	Cash flow from operations	Cash flow from operations	Dividends paid	Capital expenditures
Reported	1,834.2	1,438.9	2,129.5	545.9	316.8	104.6	384.8	384.8	110.8	277.2
Standard & Poor's adjustments										
Operating leases	9.1	--	--	0.5	0.5	0.5	3.8	3.8	--	3.9
Postretirement benefit obligations	89.5	--	--	7.4	7.4	1.7	9.0	9.0	--	--
Capitalized interest	--	--	--	--	--	3.5	(3.5)	(3.5)	--	(3.5)
Share-based compensation expense	--	--	--	3.2	--	--	--	--	--	--
Asset retirement obligations	25.2	--	--	2.1	2.1	2.1	(1.7)	(1.7)	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	0.9	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	105.6	--	--
Debt -- accrued interest not included in reported debt	23.8	--	--	--	--	--	--	--	--	--
Debt -- other	(26.2)	--	--	--	--	--	--	--	--	--
Equity -- other	--	12.4	--	--	--	--	--	--	--	--
Total adjustments	121.4	12.4	--	13.2	10.9	7.8	7.5	113.1	--	0.4

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	1,955.6	1,451.3	2,129.5	559.1	327.7	112.4	392.3	497.9	110.8	277.6

Ratings Detail (As Of September 28, 2011)*	
Vectren Corp.	
Corporate Credit Rating	A-/Stable/--
Corporate Credit Ratings History	
26-Jan-2005	A-/Stable/--
08-Jan-2003	A-/Negative/--
12-Oct-2001	A-/Stable/--

Ratings Detail (As Of September 28, 2011)*(cont.)	
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
Indiana Gas Co. Inc.	
Issuer Credit Rating	A-/Stable/NR
Senior Unsecured (15 Issues)	A-
Southern Indiana Gas & Electric Co.	
Issuer Credit Rating	A-/Stable/--
Senior Secured (8 Issues)	A
Senior Unsecured (4 Issues)	A-
Vectren Energy Delivery of Ohio Inc.	
Senior Unsecured (3 Issues)	A-
Vectren Utility Holdings Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured (3 Issues)	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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April 24, 2012

WGL Holdings Inc.

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Table Of Contents

WGL Holdings Inc.

Major Rating Factors

Corporate Credit Rating
A+/Stable/A-1

Strengths:

- Low-risk monopoly gas distribution business.
- Supportive regulatory environment with favorable cost recovery mechanisms that enhance the predictability of cash flow.
- Superior service territory with above-average income levels and a high proportion of residential customers.
- Solid consolidated financial ratios.

Weaknesses:

- WGL Holdings' strategy to increase the size and consolidated cash flow percentage of its unregulated businesses.
- Increased capital spending requirements that result in frequent rate case activity and expose the utility to the risk of regulatory lag.

Rationale

Standard & Poor's Ratings Services' ratings on Washington, D.C.-based WGL Holdings Inc. reflect the consolidated credit profile of the company's regulated and unregulated operating units. These units include Washington Gas Light Co., a regulated natural gas distribution utility that delivers to customers in the District of Columbia, Maryland, and Virginia; Washington Gas Energy Services Inc. (WGE Services; not rated), an unregulated retail gas and power marketer; and Washington Gas Energy Systems Inc. (not rated), which provides design-build energy-efficient and sustainable solutions to government and commercial clients.

We characterize WGL Holdings as having an "excellent" business risk profile and an "intermediate" financial risk profile. WGL Holdings' underlying credit strength is the stability of Washington Gas Light and its high consolidated cash flow contribution, somewhat offset by WGL Holdings' unregulated businesses, most notably WGE Services' retail energy marketing business and a growing solar business.

Washington Gas Light's excellent business risk profile reflects an affluent and stable service territory, supportive regulatory mechanisms, moderate regulatory and market diversification, and low operating risk. Supportive regulatory mechanisms enhance Washington Gas Light's cash flow stability, which further supports credit quality. The regulation in Maryland and Virginia (which together constitute more than 80% of total gas sales) is adequate, although challenging in Maryland. Adequate allowed returns on equity (ROE) and a number of recovery mechanisms including decoupling, purchase gas adjustment mechanisms, weather normalization clauses, and bad debt recovery support cost recovery and stable revenues. Washington Gas Light also benefits from a revenue-normalization mechanism in Maryland, weather-normalization and conservation mechanisms in Virginia (which accounts for more than 80% of delivered natural gas volumes), and a gas administrative charge in all three jurisdictions. Allowed ROEs have been near 10% in all three jurisdictions.

We expect WGL Holdings' nonregulated operations a to increase incrementally over the next few years. For instance, operating income from these businesses represented about 15% in 2011, up from 10% in 2010. We believe

WGL Holdings' nonregulated businesses are credit-dilutive at WGL Holdings' high rating level because, their cash flow is subject to more volatility and they lack the benefits of regulation. We expect that the increased contribution to consolidated cash flows from these businesses will weigh more heavily on WGL Holdings' credit profile than it currently does. WGE Services operates in a highly competitive industry that has minimal barriers to entry, low margins, and volatile cash flows. We expect volumes, commodity prices, and competitor pricing to propel the gas and electric businesses. WGL Holdings also has a growing solar business that consists of a fleet of solar projects located in its energy sales territories and sells electric power to its customers. We believe this business is utility-like in nature due to its long-term income stream and consider it to be generally low- to moderate-risk. However, new projects bear the risk that changes in legislation will reduce or eliminate tax credits and incentives .

WGL Holdings' financial risk profile is intermediate. We expect credit metrics to decline slightly in the near term due mainly to increased debt associated with the company's capital spending program and planned contributions for pension and postretirement benefits. The nonregulated operations produce somewhat volatile cash flows, although cash flows from Washington Gas Light should remain stable, supported by recent rate orders and tracking mechanisms. We expect WGL Holdings' annual capital expenditures to rise above $300 million in the near term, compared with current levels of slightly above $200 million, which will increase the company's debt balance and suppress credit metrics until cash flow recovers. We expect WGL Holdings to report funds from operations (FFO) to total debt of 25% or slightly higher over the next few years. For the 12 months ended Dec. 31, 2011, WGL Holdings' financial performance weakened slightly, with FFO to total debt of about 25%, while Washington Gas Light's FFO to total debt was 23%. Bonus depreciation boosted FFO to total debt ratios by about 3%, which is helpful in the near term but is not a long-term recurring benefit.

Liquidity

WGL Holdings and Washington Gas Light each have "adequate" liquidity under our corporate liquidity methodology. Adequate liquidity supports our issuer credit rating on WGL and Washington Gas Light. We expect WGL Holdings' projected sources of liquidity, mostly operating cash flow and available bank lines, to exceed its projected uses--mainly necessary capital expenditures, debt maturities, dividends, and the seasonal purchase of natural gas for winter heating by more than 1.2x.

WGL's ability to absorb high-impact, low-probability events with limited need for refinancing, its flexibility to lower capital spending or sell assets, its sound bank relationships, its solid standing in credit markets, and its generally prudent risk management further support our assessment of its liquidity as adequate. Debt maturities total about $77 million in the next 12 months. The company also has $67 million coming due in 2014, which we expect it will address well in advance of maturity.

WGL has access to a $450 million revolving credit facility expiring in April 2017 and Washington Gas has its own $350 million credit facility maturing in April 2017. Both facilities were currently undrawn as of April 15, 2012.

Liquidity is also adequate based on the following factors and assumptions:

- We expect the company's liquidity sources (including FFO and credit facility availability) to exceed its uses by more than 1.2x over the next 12 months.
- Debt maturities over the next year are manageable.
- Even if EBITDA declines by 15%, we believe net sources will be well in excess of liquidity requirements.

In our analysis, based on information available as of April 15, 2012, we assumed liquidity of about $925 million over the next 12 months, consisting of projected FFO and availability under the credit facilities. We estimate liquidity uses of slightly over $600 million during the same period for capital spending, dividends, debt maturities, and the seasonal purchase of natural gas for winter heating. Standard & Poor's does not impute a debt equivalent to guarantees that WGL Holdings provides to WGE Services for future purchases of natural gas and electricity, given the nature of the obligations and WGL Holdings' ability to cancel them. However, these guarantees, which totaled $460 million as of Dec. 31, 2011, are likely to increase as WGE Services increases its customer base. In addition, the obligation to provide natural gas or electricity to WGE Services' customers would not be reduced if the purchase obligations were terminated.

The covenants in the credit agreement require that total debt to capitalization not exceed 65%. As of Dec. 31, 2011, the company was comfortably in compliance with its debt covenants, as reported debt to capital was about 41%, and we expect it to remain so. For Washington Gas Light, reported debt to capital was about 40% against the covenant limit of 65%.

Outlook

The stable outlook on both WGL Holdings and Washington Gas Light reflects the expectation of solid consolidated financial ratios, strategy maintenance, continued regulatory support, and strong operations at Washington Gas Light. However, we could lower the rating if the nonregulated operations increase to 20% of EBITDA, accounting for a notably higher percentage of WGL Holdings' cash flows, and if management continues to pursue a more aggressive growth strategy. Specifically, a sustained FFO to debt ratio of about 22% to 23% would lead to a lower rating. Although unlikely, an upgrade would require the company to sustain consolidated FFO to debt at nearly 35%, given its current cash flow mix.

Related Criteria And Research

- Industry Report Card: U.S. Midstream Energy Sector Should Stay Stable Despite Slowing Economy, Oct. 7, 2011
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

Table 1

WGL Holdings Inc.--Peer Comparison

Industry Sector: Gas

	WGL Holdings Inc.	NiSource Inc.	Northwest Natural Gas Co.	Piedmont Natural Gas Co. Inc.
Rating as of April 24, 2012	A+/Stable/A-1	BBB-/Stable/A-3	A+/Stable/A-1	A/Stable/A-1
	--Average of past three fiscal years--			
(Mil. $)				
Revenues	2,722.4	6,363.5	891.2	1,541.4
EBITDA	353.7	1,593.9	235.3	284.8
Net income from cont. oper.	115.8	276.5	70.6	126.1
Funds from operations (FFO)	292.5	1,337.6	181.3	265.2
Capital expenditures	158.8	938.4	165.1	199.0
Free operating cash flow	145.2	438.3	45.3	150.9
Dividends paid	73.7	255.6	44.6	80.5

Table 1

WGL Holdings Inc.--Peer Comparison (cont.)				
Discretionary cash flow	71.5	182.8	0.8	70.4
Cash and short-term investments	7.0	12.4	5.9	6.7
Debt	1,000.5	8,207.1	861.9	1,028.1
Preferred stock	14.1	0.0	0.0	0.0
Equity	1,165.4	5,013.5	689.2	963.3
Debt and equity	2,165.8	13,220.6	1,551.1	1,991.3
Adjusted ratios				
EBITDA margin (%)	13.0	25.0	26.4	18.5
EBIT interest coverage (x)	5.3	2.3	3.8	4.2
Return on capital (%)	10.1	6.5	9.3	9.6
FFO int. cov. (X)	6.9	4.0	4.8	6.0
FFO/debt (%)	29.2	16.3	21.0	25.8
Free operating cash flow/debt (%)	14.5	5.3	5.3	14.7
Discretionary cash flow/debt (%)	7.1	2.2	0.1	6.8
Net cash flow / capex (%)	137.8	115.3	82.8	92.8
Debt/EBITDA (x)	2.8	5.1	3.7	3.6
Total debt/debt plus equity (%)	46.2	62.1	55.6	51.6
Return on capital (%)	10.1	6.5	9.3	9.6
Return on common equity (%)	10.2	5.6	10.5	12.6
Common dividend payout ratio (un-adj.) (%)	66.1	92.5	63.2	63.8

Table 2

WGL Holdings Inc.--Financial Summary					
Industry Sector: Gas					
	--Fiscal year ended Sept. 30--				
	2011	**2010**	**2009**	**2008**	**2007**
Rating history	A+/Stable/A-1	AA-/Negative/A-1+	AA-/Stable/A-1	AA-/Stable/A-1	AA-/Stable/A-1
(Mil. $)					
Revenues	2,751.5	2,708.9	2,706.9	2,628.2	2,646.0
EBITDA	374.2	343.8	343.1	338.5	343.7
Net income from cont. oper.	117.1	109.9	120.4	116.5	107.9
Funds from operations (FFO)	318.6	268.7	290.3	216.9	209.3
Capital expenditures	203.6	131.4	141.3	138.3	165.1
Dividends paid	73.6	75.9	71.7	68.5	66.2
Debt	1,049.7	997.7	953.9	855.2	835.4
Preferred stock	14.1	14.1	14.1	14.1	14.1
Equity	1,216.8	1,167.5	1,111.8	1,061.7	994.9
Debt and equity	2,266.6	2,165.2	2,065.7	1,916.9	1,830.3
Adjusted ratios					
EBITDA margin (%)	13.6	12.7	12.7	12.9	13.0
EBIT interest coverage (x)	5.5	5.2	5.2	4.8	4.8

Table 2

WGL Holdings Inc.--Financial Summary (cont.)					
FFO int. cov. (x)	7.1	6.7	7.0	5.3	4.9
FFO/debt (%)	30.4	26.9	30.4	25.4	25.1
Discretionary cash flow/debt (%)	2.4	9.1	10.3	(15.7)	(1.1)
Net Cash Flow / Capex (%)	120.3	146.8	154.7	107.3	86.7
Debt/debt and equity (%)	46.3	46.1	46.2	44.6	45.6
Return on capital (%)	10.2	9.5	10.7	11.2	12.1
Return on common equity (%)	9.7	9.6	11.2	11.4	11.3
Common dividend payout ratio (un-adj.) (%)	68.2	70.5	60.1	59.3	61.9

Table 3

Reconciliation Of WGL Holdings Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)								
	--Fiscal year ended Sept. 30, 2011--							
WGL Holdings Inc. reported amounts								
	Debt	**Shareholders' equity**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Capital expenditures**
Reported	703.7	1,230.9	335.1	243.8	40.5	295.7	295.7	201.5
Standard & Poor's adjustments								
Operating leases	27.8	--	1.5	1.5	1.5	3.9	3.9	3.1
Intermediate hybrids reported as equity	14.1	(14.1)	--	--	0.7	(0.7)	(0.7)	--
Postretirement benefit obligations	255.1	--	27.5	27.5	3.3	7.5	7.5	--
Capitalized interest	--	--	--	--	1.0	(1.0)	(1.0)	(1.0)
Share-based compensation expense	--	--	6.9	--	--	--	--	--
Asset retirement obligations	45.2	--	3.1	3.1	3.1	(2.8)	(2.8)	--
Reclassification of nonoperating income (expenses)	--	--	--	1.0	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	15.9	--
Debt - Accrued interest not included in reported debt	3.9	--	--	--	--	--	--	--
Debt - Other	(0.0)	--	--	--	--	--	--	--
Total adjustments	346.0	(14.1)	39.1	33.1	9.6	7.0	22.9	2.1
Standard & Poor's adjusted amounts								
	Debt	**Equity**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Capital expenditures**
Adjusted	1,049.7	1,216.8	374.2	276.9	50.2	302.7	318.6	203.6

Ratings Detail (As Of April 24, 2012)	
WGL Holdings Inc.	
Corporate Credit Rating	A+/Stable/A-1
Commercial Paper	
Local Currency	A-1
Corporate Credit Ratings History	
18-Mar-2011	A+/Stable/A-1
16-Jun-2010	AA-/Negative/A-1+
09-Jun-2010	AA-/Negative/A-1
27-Jun-2007	AA-/Stable/A-1
Business Risk Profile	Excellent
Financial Risk Profile	Intermediate
Related Entities	
Washington Gas Light Co.	
Issuer Credit Rating	A+/Stable/A-1
Commercial Paper	
Local Currency	A-1
Preferred Stock	A-
Senior Secured	A+
Senior Unsecured	A+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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July 5, 2011

Wisconsin Energy Corp.

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Table Of Contents

Wisconsin Energy Corp.

Major Rating Factors

Corporate Credit Rating
A-/Stable/A-2

Strengths:

- A more credit-supportive regulatory environment and effective management of regulatory risk;
- Limited higher-risk unregulated activities; and
- Solid operational performance.

Weaknesses:

- A weakened (albeit slowly recovering) service-area economy;
- Currently heavy construction outlays; and
- Declining but still somewhat aggressive consolidated debt leverage.

Rationale

Standard & Poor's Ratings Services' ratings on Milwaukee-based electric and natural gas utility holding company Wisconsin Energy Corp. (WEC) reflect an excellent business risk profile and a significant financial risk profile. (We rank utilities' business risk profiles from excellent to vulnerable and their financial risk profiles from minimal to highly leveraged. For more on business risk and financial risk, see "Business Risk/Financial Risk Matrix Expanded," published May 27, 2009, on RatingsDirect on the Global Credit Portal.) WEC's regulated operating subsidiaries are Wisconsin Electric Power Co. (WEPCO) and Wisconsin Gas LLC (WG), whose business profiles are also excellent. As part of the company's Power the Future strategy, unregulated subsidiary W.E. Power was formed in 2001 to design, construct, own, finance, and lease new generating capacity to WEPCO.

WEC's business risk profile benefits from a responsive regulatory environment in Wisconsin characterized by supportive cost-recovery ratemaking mechanisms, solid operational performance, recent completion of major generation additions, a cost-conscious management team, and a focus on a straightforward electric and gas utility business model. In addition, the utilities manage regulatory risk effectively, as demonstrated by rate decisions that provide steady earnings and cash flow. A somewhat weak service territory economy tempers these strengths, although it's slowly beginning to recover, and currently heavy capital outlays for environmental initiatives and for renewable energy projects to meet the state's current renewable portfolio standard.

With regard to the company's capital program, construction has commenced on Glacier Hills, a $361 million 162-megawatt (MW) wind farm slated for completion by the end of 2011. And, the company has received all local permits and Public Service Commission of Wisconsin (PSCW) approval to move forward on a $255 million biomass project (50 MW) targeted for completion in 2013. Furthermore, upgrades of air quality controls at the Oak Creek Units 5-8 are about 75% complete and are expected to be finished in 2012, on budget for about $900 million (including allowance for funds during construction).

The 615-MW coal-fired Oak Creek Unit 2 was declared commercial on January 12, 2011, and Oak Creek Unit 1, also 615 MW, was completed on Feb. 2, 2010. The company had received PSCW preconstruction approval of the station and authorization of a 30-year lease agreement between affiliate W.E. Power and WEPCO for a 12.7%

return on equity (55% common equity and 45% debt capital structure) plus recovery of all operating costs through the utility's rates.

We view Wisconsin's regulatory climate as more credit supportive, and the utilities continue to manage regulatory risk effectively, as demonstrated by rate orders that provide steady earnings and cash flow. New fuel rules (set at plus or minus a 2% deadband) allow for recovery of any under-or-over collected fuel costs outside a general rate case, which reduces exposure to power price volatility. Recently, the company filed an alternative approach to a traditional rate proceeding with the PSCW in order to avoid raising customer rates in 2012 and keep the slow economic recovery moving ahead in its service area. The company has requested authorization to suspend amortization of $148 million of regulatory costs in 2012 and approval of $148 million of carrying costs and depreciation on air quality controls at Oak Creek Units 5-8 and Glacier Hills Wind Park. The company has also asked for approval to reopen the rate proceeding in 2012 for rates effective in 2013. If the commission does not approve the proposals by mid-July 2011, the company will file a traditional rate case.

Although WEC plans to implement up to a $300 million share repurchase program through 2013 and gradually increase its dividend payout to 60% of earnings (from about 41% in 2010) beginning in 2012, it is doing so with the estimated $600 million of free cash flow it expects to have through 2015 (largely from bonus depreciation and completion of its Power the Future program). Furthermore, WEC retired $450 million of long-term debt in April 2011. While using all the cash to pare debt would have had the most positive impact on the company's financial condition, WEC's strategy appears to be a relatively balanced approach to its use of free cash flow. And, the company still plans to reduce debt, albeit very modestly. With diminishing capital expenditures after 2011, continued modest economic recovery in the region, prospects for additional future rate relief, and well-controlled expenses, key measures of bondholder protection should continue to support the current rating. In that regard, our base forecast includes adjusted funds from operations (FFO) to total debt hovering at about 19% to 20% and adjusted total debt total capital falling to around 55% in the foreseeable future. When calculating these ratios, Standard & Poor's considers WEC's hybrid securities as having intermediate equity content and adjusts ratios for operating leases, pensions and other post-retirement obligations, and purchased-power agreements.

Liquidity

The short-term rating on WEC and its utility subsidiaries is 'A-2' and largely reflects the long-term corporate credit ratings and our view of the company's adequate liquidity under Standard & Poor's corporate liquidity methodology, which categorizes liquidity in five standard descriptors. (For more on liquidity, see "Standard & Poor's Standardizes Liquidity Descriptors For Global Corporate Issuers," published July 2, 2010.) Projected sources of liquidity, mainly operating cash flow and available bank lines, exceed projected uses, mainly necessary capital expenditures, debt maturities, and dividends, by more than 1.2x. WEC's ability to absorb high-impact, low-probability events with limited need for refinancing, its flexibility to lower capital spending or sell assets, its sound bank relationships, its solid standing in credit markets, and its generally prudent risk management further support our description of liquidity as adequate.

In December 2010, the company entered into new bank credit facilities totaling $1.250 billion ($450 million at WEC, $500 million at WEPCO, and $300 million at WG) that expire in December 2013. The bank facilities require the parent and the utilities to maintain a minimum total funded debt-to-capitalization ratio of 70% and 65%, respectively, with which they comfortably comply.

At the end of March 2011, WEC had a combined total of approximately $1.2 billion of available undrawn lines under its bank back-up credit facilities, and about $281.5 million of commercial paper outstanding that was supported by the available lines of credit.

On April 1, 2011, WEC retired $450 million of long-term debt using $223 million of cash on hand and commercial paper borrowings. The company has a manageable maturity ladder, with $300 million debt at WEPCO coming due in May 2013. We expect that the company will address issuance well in advance of the due date and that WEC will continue to meet its cash needs in a credit-neutral manner. Also, given WEC's focus on relatively low-risk electric and gas operations and regulatory mechanisms that provide for the timely recovery of costs, prospective cash flows should be reasonably predictable.

Outlook

The stable outlook on the ratings reflects Standard & Poor's baseline forecast that the company's consolidated adjusted FFO to total debt will continue to hover around 19% to 20% and that adjusted debt to total capital will fall to approximately 55% over the intermediate term. Fundamental to our forecast are a continued slow economic recovery in the company's service territory, a limitation of stock buybacks or dividend increases to those already announced by WEC, and the outcome of current and future rate filings in Wisconsin and Michigan. Ratings stability also assumes steady progress on the company's environmental compliance and renewable energy projects, with no cost overruns. Pressure on the ratings could come from deterioration in key financial metrics, changes in Wisconsin's more credit-supportive or Michigan's credit-supportive regulatory climate (although we consider that unlikely), or the company's inability to effectively manage its regulatory risk. We could lower the ratings if WEC's consolidated financial profile were to erode to a point where total debt to total capital rose above 58% and FFO to total debt fell to around 16%. We do not currently contemplate higher ratings.

Related Research And Criteria

- Standard & Poor's Standardizes Liquidity Descriptors For Global Corporate Issuers, July 2, 2010
- Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Analytical Methodology, April 15, 2008

Table 1

Wisconsin Energy Corp.--Peer Comparison

Industry Sector: Combo

	Wisconsin Energy Corp.	Xcel Energy Inc.	Alliant Energy Corp.	SCANA Corp.	Progress Energy Inc.
Rating as of July 5, 2011	A-/Stable/A-2	A-/Stable/A-2	BBB+/Positive/A-2	BBB+/Stable/A-2	BBB+/Watch Pos/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	4,253.8	10,385.6	3,510.2	4,719.0	9,747.3
EBITDA	807.4	2,524.8	874.8	1,094.4	3,089.4
Net income from cont. oper	396.7	694.4	239.1	359.7	823.0
Funds from operations (FFO)	968.4	2,004.8	776.7	776.5	2,218.9
Capital expenditures	898.1	2,052.6	1,052.4	897.3	2,547.3

Table 1

Wisconsin Energy Corp.--Peer Comparison (cont.)					
Free operating cash flow	106.0	(67.7)	(339.1)	(266.1)	(459.7)
Dividends paid	172.4	422.9	167.9	229.6	724.3
Discretionary cash flow	(66.4)	(490.5)	(507.1)	(495.6)	(1,184.0)
Cash and short-term investments	90.8	155.1	227.2	163.0	505.3
Debt	5,426.0	10,963.4	3,441.2	5,257.1	14,718.8
Preferred stock	265.2	252.5	121.9	68.8	182.5
Equity	3,833.8	7,696.0	2,953.9	3,453.8	9,574.2
Debt and equity	9,259.8	18,659.4	6,395.1	8,710.9	24,293.0
Adjusted ratios					
EBITDA margin (%)	19.0	24.3	24.9	23.2	31.7
EBIT interest coverage (x)	2.1	2.7	3.0	2.8	2.5
Return on capital (%)	5.3	8.0	8.1	8.5	8.8
FFO int. cov. (X)	4.8	4.1	4.8	3.6	3.4
FFO/debt (%)	17.8	18.3	22.6	14.8	15.1
Free operating cash flow/debt (%)	2.0	(0.6)	(9.9)	(5.1)	(3.1)
Discretionary cash flow/debt (%)	(1.2)	(4.5)	(14.7)	(9.4)	(8.0)
Net cash flow / capex (%)	88.6	77.1	57.9	61.0	58.7
Debt/EBITDA (x)	6.7	4.3	3.9	4.8	4.8
Total debt/debt plus equity (%)	58.6	58.8	53.8	60.4	60.6
Return on capital (%)	5.3	8.0	8.1	8.5	8.8
Return on common equity (%)	8.8	8.2	6.8	9.7	7.4
Common dividend payout ratio (unadj.) (%)	39.6	64.2	74.8	64.4	84.1

Table 2

Wisconsin Energy Corp.--Financial Summary					
Industry Sector: Combo					
	--Fiscal year ended Dec. 31--				
	2010	**2009**	**2008**	**2007**	**2006**
Rating history	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Positive/A-2	BBB+/Stable/A-2	BBB+/Negative/A-2
(Mil. $)					
Revenues	4,202.5	4,127.9	4,431.0	4,237.8	3,996.4
EBITDA	1,016.2	844.2	561.8	1,010.6	915.7
Net income from cont. oper.	454.4	377.2	358.6	336.5	312.5
Funds from operations (FFO)	1,012.6	908.2	984.3	803.6	669.1
Capital expenditures	780.4	754.6	1,159.2	1,179.8	921.9
Dividends paid	202.0	172.8	142.3	125.9	107.6
Debt	5,492 9	5,422.1	5,362.8	4,815.2	4,594.7
Preferred stock	265.2	265.2	265.2	265.2	30.4
Equity	4,067.3	3,832.1	3,602.1	3,364.4	2,919.4
Debt and equity	9,560.2	9,254.2	8,964.9	8,179.5	7,514.1

Table 2

Wisconsin Energy Corp.--Financial Summary (cont.)					
Adjusted ratios					
EBITDA margin (%)	24.2	20.5	12.7	23.8	22.9
EBIT interest coverage (x)	2.8	2.2	1.1	2.9	3.1
FFO int. cov. (x)	4.8	4.7	5.0	4.3	4.1
FFO/debt (%)	18.4	16.7	18.4	16.7	14.6
Discretionary cash flow/debt (%)	(0.1)	0.8	(4.4)	(17.5)	(7.2)
Net Cash Flow / Capex (%)	103.9	97.4	72.6	57.4	60.9
Debt/debt and equity (%)	57.5	58.6	59.8	58.9	61.1
Return on capital (%)	7.3	5.4	2.9	8.8	8.6
Return on common equity (%)	10.0	8.2	8.2	8.6	9.8
Common dividend payout ratio (unadj.) (%)	41.2	41.8	35.2	34.7	34.4

Table 3

Reconciliation Of Wisconsin Energy Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)								
	--Fiscal year ended Dec. 31, 2010--							
Wisconsin Energy Corp. reported amounts								
	Debt	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**
Reported	5,063.3	3,832.5	4,202.5	917.6	612.0	206.4	808.3	808.3
Standard & Poor's adjustments								
Operating leases	68.3	--	--	3.5	3.5	3.5	18.6	18.6
Intermediate hybrids reported as debt	(250.0)	250.0	--	--	--	(15.6)	15.6	15.6
Intermediate hybrids reported as equity	15.2	(15.2)	--	--	--	0.6	(0.6)	(0.6)
Postretirement benefit obligations	204.7	--	--	24.9	24.9	--	(13.2)	(13.2)
Capitalized interest	--	--	--	--	--	52.3	(52.3)	(52.3)
Share-based compensation expense	--	--	--	35.1	--	--	--	--
Power purchase agreements	357.2	--	--	32.1	18.4	18.4	13.7	13.7
Asset retirement obligations	34.2	--	--	3.1	3.1	3.1	(0.4)	(0.4)
Reclassification of nonoperating income (expenses)	--	--	--	--	100.3	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	36.7
FFO - Other	--	--	--	--	--	--	186.2	186.2
Total adjustments	429.6	234.8	0.0	98.6	150.1	62.2	167.6	204.3

Table 3

Reconciliation Of Wisconsin Energy Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations
Adjusted	5,492.9	4,067.3	4,202.5	1,016.2	762.1	268.6	975.9	1,012.6

Ratings Detail (As Of July 5, 2011)*

Wisconsin Energy Corp.	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated (1 Issue)	BBB
Senior Unsecured (1 Issue)	BBB+
Corporate Credit Ratings History	
27-Jun-2011	A-/Stable/A-2
17-Mar-2011	BBB+/Positive/A-2
08-Jul-2009	BBB+/Stable/A-2
02-Jul-2008	BBB+/Positive/A-2
31-Jul-2007	BBB+/Stable/A-2
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
Elm Road Generating Station Supercritical, LLC	
Senior Unsecured (2 Issues)	A-
Wisconsin Electric Power Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured (10 Issues)	A-
Wisconsin Energy Capital Corp.	
Issuer Credit Rating	A-/Stable/--
Wisconsin Gas LLC	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured (3 Issues)	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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Table Of Contents

Xcel Energy Inc.

Major Rating Factors

Corporate Credit Rating
A-/Stable/A-2

Strengths:

- Diversity of geography, fuel, and economy;
- Fully regulated utilities strategy;
- Credit-supportive regulation; and,
- Strengthened financial profile.

Weaknesses:

- Aggressive capital spending;
- Dependence on supportive cost recovery; and,
- Free operating cash flow negative.

Rationale

Standard & Poor's Ratings Services bases its rating on Minneapolis-based Xcel Energy Inc. on the consolidated credit profile that includes what we consider to be an "excellent" business risk profile and "significant" financial risk profile (as our criteria define the terms). The outlook is stable.

The excellent business risk profile assessment incorporates Xcel's strategy as a geographically and economically diverse public utility holding company that owns four utilities, serving about 3.5 million electric and 2 million natural-gas customers in eight states from the upper Midwest, over to Colorado, and down to the Texas Panhandle and New Mexico.

The consolidated financial risk profile, which we consider significant, reflects adjusted financial measures from our baseline forecast that are in line with the rating. In addition, we consider the company's financial policies to be credit-supportive and transparent. We believe the company will perform relatively well compared with its peers even though financial measures may erode modestly due to less cash flow recovery while undertaking its capital spending plan in Colorado.

Our base forecast of about 20% funds from operations (FFO) to total debt, 4.3x debt to EBITDA, and 58% total debt to total capital continues to reflect steady economic activity in the company's largest service territories in Minnesota and Colorado. Xcel's rating reflects a fully regulated utility strategy that includes continuous capital spending and dependence on ongoing and timely cost recovery. We expect this to lead to continuing robust cash flow measures and manageable debt leverage.

Outlook: Stable

The stable outlook on Xcel and its subsidiaries reflects our expectation that management will continue to reach constructive regulatory outcomes to avoid any meaningful rise in business risk for the regulated utilities. The outlook also includes our projection of strengthening cash flow protection measures after cost recovery of pending construction projects begins. Specifically, our base forecast includes FFO to total debt of about 20%, debt to EBITDA less than 4.3x, and debt leverage to total capital below 58%, consistent with our expectations for the rating. Given the company's focus on regulated utility operations, we expect that Xcel will continue to reach constructive regulatory outcomes to avoid any meaningful rises in business risk and will fund capital investments in a balanced manner to support the capital structure.

We could lower ratings if financial measures weaken and remain at less-supportive levels, including FFO to total debt below 15%, 4.5x debt to EBITDA, and debt to total capital in excess of 58%.

We could raise ratings if financial measures consistently exceed our baseline forecast, including FFO to total debt greater than 21%, debt to EBITDA below 4x, and debt to total capital under 55%.

Business Description

Xcel is an integrated electric and natural gas utility holding company that owns vertically integrated utilities Northern States Power Co. (NSP), Northern States Power Wisconsin (NSP-W), Public Service Co. of Colorado (PSCo), and Southwestern Public Service Co. (SPS).

Northern States Power

NSP is a vertically integrated electric utility and a local gas distribution company that sells electricity and natural gas mainly in Minnesota, including Minneapolis/St. Paul, and small sections of North Dakota and South Dakota. The company serves about 1.4 million electric and 500,000 gas customers and almost 90% of the revenues come from Minnesota. NSP contributes 35% to 45% of the consolidated earnings of Xcel.

Northern States Power Wisconsin

NSP-W is a vertically integrated electric utility and a local gas distribution company that sells electricity and natural gas in western and northwestern Wisconsin, and the western edge of Michigan's Upper Peninsula. It serves about 250,000 electric and 105,000 gas customers and almost all of the revenues are from Wisconsin. The company contributes 5% to 10% of the consolidated earnings of Xcel.

Public Service Co. of Colorado

PSCo is a vertically integrated electric utility and a local gas distribution company that sells electricity and natural gas in central Colorado, including Denver and Boulder. The company serves about 1.4 million electric and 1.3 million gas customers. The company contributes 45% to 55% of the consolidated earnings of Xcel.

Southwestern Public Service

SPS sells electricity in the Panhandle region of Texas (Amarillo and surrounding area) and smaller areas in eastern New Mexico. It serves about 375,000 electric customers and about three-quarters of its revenues are from Texas. The company contributes 5% to 15% of the consolidated earnings of Xcel.

Rating Methodology

We assign ratings on Xcel and its subsidiaries that reflect the consolidated credit profile of the entire group, acknowledging the lack of any meaningful measures that can prevent the free flow of cash throughout the enterprise. We view Xcel as a single economic entity because the regulated utilities are core to the corporate strategy. As a result, we view that the likelihood of default is the same throughout the organization.

Business Risk Profile: Excellent. Large Regulated Operations With Credit-Supportive Regulation

Xcel's excellent business risk profile reflects operations as a sole provider in its service territories (the largest are in Minnesota and Colorado) of essential services, electricity and natural gas distribution that remain regulated. This provides a measure of support and insulation from market challenges. With operations across eight states, Xcel benefits significantly from regional, geographical, and regulatory diversity, potentially minimizing the effect of economic conditions in one particular state or adverse regulatory decisions. The customer base for the regulated utilities (both electric and gas) is primarily residential and commercial customers in terms of revenues as well as sales, which provides stable cash flows. The diversity in markets and regulation strengthens credit quality, but the numerous regulatory jurisdictions require diligent filing for rate recovery. The company has a low-cost and diversified generation portfolio and mostly credit-supportive regulation, particularly in Colorado, Minnesota, and Wisconsin that account for about 90% of Xcel's consolidated operating cash flow.

Management and strategy

Xcel's management has done a good job of managing regulatory risk, implementing risk-management strategies, controlling expenses, and providing high-quality service. It has not pursued risky unregulated diversified activities, and has demonstrated it can access the debt and equity markets. We believe that management's depth, specificity, and transparency in its financial goals have been sufficient. Strategic positioning appears consistent, with organizational capabilities and marketplace conditions. Management has executed on a strategy of building rate base and new generation projects and completing rate cases and rider filings on a timely basis. The ability to convert its regulated strategy into constructive action is positive for credit quality.

S&P base case operating expectations

Standard & Poor's base case scenario for Xcel indicates:

- The company remains a holding company that owns fully regulated electric utilities and natural gas distribution utilities.
- The economic conditions in the company's service territories are improving, which will likely increase customer usage.
- The customer base is largely residential and commercial, which is beneficial because such customers generally maintain their electricity usage, providing at least a base level of usage. While there is some wholesale sales exposure for SPS, there is no meaningful customer concentration.
- Xcel has efficient electricity generating operations that produce competitively priced power, high levels of plant utilization, a low level of unforced outages, and high reliability. In addition, the gas distribution operations are

viewed as having low operating risk.

- Utility subsidiaries operate under regulatory terms that largely support credit quality and are generally constructive, which includes good fuel-clause mechanisms and other cost pass-through mechanisms.
- There is effective management of regulatory relationships.
- Xcel continues spending on new generation and pollution-control equipment while seeking higher operating cash flow through various rate riders and base rate proceedings.
- Xcel continues to spend on low-risk transmission projects in its service territories.

Profitability/ Peer comparison

Table 1

Xcel Energy Inc. -- Peer Comparison

Industry Sector: Combo

	Xcel Energy Inc.	**American Electric Power Co. Inc.**	**Duke Energy Corp.**	**Entergy Corp.**	**Progress Energy Inc.**
Rating as of June 4, 2012	A-/Stable/A-2	BBB/Stable/A-2	A-/Stable/A-2	BBB/Negative/--	BBB+/Watch Pos/A-2
(Mil. $)	**--Average of past three fiscal years--**				
Revenues	10,202.8	14,093.5	13,844.0	11,082.1	9,660.7
EBITDA	2,689.8	4,421.1	4,760.6	3,529.7	3,077.5
Operating income	1,720.8	2,897.7	2,958.2	2,464.3	2,072.6
Net income from cont. oper.	759.6	1,383.0	1,361.7	1,296.2	758.7
Funds from operations (FFO)	2,226.2	3,518.1	3,969.0	3,171.3	2,273.2
Capital expenditures	2,085.3	2,797.7	4,468.4	2,707.2	2,459.2
Free operating cash flow	168.7	576.7	(207.0)	517.1	(151.1)
Discretionary cash flow	(285.1)	(265.1)	(1,509.7)	(83.2)	(877.7)
Cash and short-term investments	124.1	692.7	1,837.3	1,232.8	522.0
Debt	11,330.0	20,671.1	20,272.4	13,687.4	15,338.7
Preferred stock	235.0	177.7	0.0	150.4	182.7
Equity	8,184.6	13,986.7	22,468.0	8,840.8	10,018.3
Adjusted ratios					
EBITDA margin (%)	26.4	31.4	34.4	31.9	31.9
EBITDA interest coverage (x)	4.2	3.8	4.6	4.3	3.4
EBIT interest coverage (x)	2.9	2.8	3.3	3.2	2.4
Return on capital (%)	8.1	7.8	7.1	8.7	8.2
FFO/debt (%)	19.6	17.0	19.6	23.2	14.8
Free operating cash flow/debt (%)	1.5	2.8	(1.0)	3.8	(1.0)
Discretionary cash flow/debt (%)	(2.5)	(1.3)	(7.4)	(0.6)	(5.7)
Debt/EBITDA (x)	4.2	4.7	4.3	3.9	5.0
Total debt/debt plus equity (%)	58.1	59.6	47.4	60.8	60.5

Financial Risk Profile: Significant. Substantial Leverage And Steady Cash Flow

We view Xcel's financial risk profile as significant. Xcel's steady operating cash flows from its regulated utilities resulted in FFO to total debt (21% for the 12 months ended March 31, 2012) that was marginally within the 20% to 30% that we associate with a significant profile. Other measures, including debt to EBITDA of 4.2x and total debt to total capital of 58%, were minimally above the 3x to 4x and 45% to 50% ranges, respectively, for a significant profile. FFO interest coverage was a supportive 4.7x, and the company's dividend payout ratio was manageable at 62%, albeit creeping up from previous levels. The company is extremely capital intensive as indicated by net cash flow (FFO less dividends) to capital spending marginally under 100%, at 92%. After reducing cash flow from operations with capital spending and dividends, discretionary cash flow was negative by $259 million. Both these measures indicate external funding needs.

Table 2

Cash Flow Waterfall

Annual cash flow measures (mil. $)	2006	2007	2008	2009	2010	2011
EBITDA	2,159.1	2,361.3	2,414.6	2,478.8	2,680.8	2,909.7
Funds from operations (FFO)	1,359.8	1,858.0	1,843.9	1,979.2	2,191.2	2,508.2
Working capital	(448.0)	289.7	71.5	(212.3)	200.4	(71.4)
Cash flow from operations	1,807.7	1,568.4	1,772.4	2,191.5	1,990.9	2,579.6
Capital expenditures	1,571.6	2,088.6	2,110.4	1,834.4	2,213.0	2,208.3
Free operating cash flow (FOCF)	236.1	(520.2)	(338.0)	357.1	(222.1)	371.3
Dividends	358.7	376.8	395.4	428.0	445.2	488.2
Discretionary cash flow (DCF)	(122.6)	(897.0)	(733.4)	(70.9)	(667.3)	(116.9)
Debt	8,964.0	9,456.8	10,783.5	10,555.5	11,551.3	11,883.3
Equity	5,870.9	6,353.5	7,216.2	7,535.7	8,336.0	8,682.2
EBITDA interest coverage (x)	3.7	3.6	3.8	4.0	4.2	4.4
FFO interest coverage (x)	3.2	3.7	3.8	4.1	4.4	4.7
FFO/debt (%)	15.2	19.6	17.1	18.8	19.0	21.1
FOCF/debt (%)	2.6	(5.5)	(3.1)	3.4	(1.9)	3.1
DCF/debt (%)	(1.4)	(9.5)	(6.8)	(0.7)	(5.8)	(1.0)
Net cash flow/capex (%)	63.7	70.9	68.6	84.6	78.9	91.5
Debt/EBITDA (x)	4.2	4.0	4.5	4.3	4.3	4.1
Debt/debt and equity (%)	60.4	59.8	59.9	58.3	58.1	57.8
Dividend payout ratio (%)	63.0	66.9	64.8	65.4	62.7	60.1

S&P base case cash flow and capital structure expectations

Our base case forecast suggests mostly steady key credit measures over the next several years. We expect financial measures will mostly remain around current levels, neither materially weakening nor strengthening, over the next several years. We do expect net cash flow to capital spending to decline to around 70% and discretionary cash flow to become more negative over the next several years, both due to growing capital expenditures and a rising dividend. We project that FFO interest coverage will be more than 5x. We derive the base case forecast financial measures from our assumptions, including:

- Over next several years, capital spending trending higher to meet environmental requirements.
- Accelerating capital spending for electric construction, including environmental upgrades, generation, and improvements to its gas and electric facilities, results in weakening internal funding and reliance on debt and equity markets.
- EBITDA growth consisting of revenue increases and customer growth expected to be about the same as recent years.
- Refinancing of upcoming debt maturities.
- Dividend payout ratio similar to current levels and dividend growth rate of 2% to 4%.
- As the company has publicly indicated, external funding needs consisting of new debt issuances of $2.8 billion and equity issuances of roughly $1.2 billion over the next several years.
- Maintaining what we believe is an adequate liquidity assessment.
- Maintaining what we consider conservative financial policies.
- Continuing commitment to credit quality and the maintenance of a balanced capital structure.

Liquidity

We consider Xcel's liquidity as "adequate" under Standard & Poor's liquidity methodology. We base our liquidity assessment on the following factors and assumptions:

- We expect Xcel's liquidity sources over the next 12 months, including cash ($60 million), FFO ($2.4 billion), and credit facility availability ($2.2 billion), to exceed uses by 1.2x, which is the minimum threshold for an "adequate" designation. Uses include necessary capital spending ($2.1 billion), working capital ($65 million), debt maturities ($1.06 billion), and shareholder distributions ($520 million).
- Debt maturities are manageable over the next 12 months with $1.06 billion due this year. Debt maturities are manageable through 2015, with $258 million in 2013, $284 million in 2014, and $257 million in 2015. All these debt maturities are at Xcel's utilities and we expect will be refinanced.
- We believe liquidity sources would exceed uses even if EBITDA declines 15%.
- In our assessment, Xcel has good relationships with its banks, and has a good standing in the credit markets, having successfully issued debt during the recent credit crisis.

Xcel's and its subsidiaries' credit agreements include financial covenants requiring debt to total capitalization no greater than 65%. As of Dec. 31, 2011, Xcel and its subsidiaries were in compliance with the covenants in their respective credit facilities.

Table 3

Covenant Compliance – As of Dec. 31, 2011

	Maximum (%)	Actual
Xcel Energy	65	55
Northern States Power	65	48
Northern States Power Wisconsin	65	50
Public Service Co. of Colorado	65	45
Southwest Public Service Co.	65	48

Standard & Poor's adjusts ratios to account for its intermediate equity treatment of Xcel's junior subordinated note, operating leases, pension-related items, and a risk-based share of certain power-purchase agreement (PPA) obligations.

Table 4

Reconciliation Of Xcel Energy Inc. Reported Amounts With Standard & Poor's Adjusted Amounts

	--Fiscal year ended Dec. 31, 2011--						
Xcel Energy Inc. reported amounts							
(Mil. $)	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**
Reported	10,127.4	8,482.2	10,654.8	2,672.2	1,781.6	562.9	2,405.5
Standard & Poor's adjustments							
Operating leases	155.6	--	--	10.0	10.0	10.0	17.5
Intermediate hybrids reported as debt	(200.0)	200.0	--	--	--	(15.2)	15.2
Intermediate hybrids reported as equity	--	--	--	--	--	1.8	(1.8)
Postretirement benefit obligations	588.9	--	--	40.5	40.5	--	100.3
Capitalized interest	--	--	--	--	--	28.2	(28.2)
Share-based compensation expense	--	--	--	43.9	--	--	--
Power purchase agreements	924.4	--	--	133.8	57.1	57.1	76.7
Asset retirement obligations	109.9	--	--	9.3	9.3	9.3	(5.7)
Non-operating income (expense)	--	--	--	--	91.0	--	--
Reverse changes in working-capital	--	--	--	--	--	--	--
Debt - Accrued interest not included in reported debt	177.1	--	--	--	--	--	--
Total adjustments	1,755.9	200.0	0.0	237.4	207.9	91.1	174.1
Standard & Poor's adjusted amounts							
	Debt	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**
Adjusted	11,883.3	8,682.2	10,654.8	2,909.7	1,989.5	654.1	2,579.6

Recovery Analysis

We rate the senior unsecured debt at Xcel one rating lower than the corporate credit rating because of structural subordination. This results from priority obligations exceeding 20% of total assets absent any goodwill. We rate the senior unsecured debt at the operating utilities the same as their corporate credit ratings. Certain senior secured debt at the operating utilities is rated higher than the corporate credit rating due to first liens on the respective utility's property.

We assign recovery ratings to first mortgage bonds (FMB) issued by investment-grade U.S. utilities, which can result in our notching issue ratings above a utility's corporate credit rating (CCR) depending on the CCR category and the extent of the collateral coverage. We base the investment-grade FMB recovery methodology on the ample historical record of nearly 100% recovery for secured bondholders in utility bankruptcies and on our view that the factors that supported those recoveries (limited size of the creditor class, and the durable value of utility rate-based assets during and after a reorganization, given the essential service provided and the high replacement cost) will persist in the future. Under our notching criteria, when assigning issue ratings to utility FMBs, we consider the limitations of FMB issuance under the utility's indenture relative to the value of the collateral pledged to bondholders, management's stated intentions on future FMB issuance, as well as the regulatory limitations on bond issuance. FMB ratings can exceed a utility's CCR by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories.

NSP's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of 1.5x supports a recovery rating of '1+' and an issue rating one notch above the CCR.

NSP-Wisconsin's FMBs benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of 1.5x supports a recovery rating of '1+' and an issue rating one notch above the CCR.

PSCo's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral in combination with non-indenture-related covenants provide coverage of more than 1.5x, supporting a recovery rating of '1+' and an issue rating one notch above the CCR.

SPS' FMBs benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of less than 1.5x supports a recovery rating of '1' and an issue rating with no notches above the CCR.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- Changes To Collateral Coverage Requirements For '1+' Recovery Ratings On U.S. Utility First Mortgage Bonds, Sept. 6, 2007

Ratings Detail (As Of June 26, 2012)	
Xcel Energy Inc.	
Corporate Credit Rating	A-/Stable/A-2
Junior Subordinated	BBB
Senior Unsecured	BBB+
Corporate Credit Ratings History	
23-Jun-2010	A-/Stable/A-2
10-Jun-2009	BBB+/Positive/A-2
16-Oct-2007	BBB+/Stable/A-2
Business Risk Profile	Excellent
Financial Risk Profile	Significant

Ratings Detail (As Of June 26, 2012) (cont.)	
Related Entities	
Northern States Power Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Northern States Power Wisconsin	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Public Service Co. of Colorado	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Southwestern Public Service Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A-
Senior Unsecured	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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November 23, 2011

Canadian Utilities Ltd.

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Table Of Contents

Canadian Utilities Ltd.

Major Rating Factors

Strengths:
- Favorable diversity
- Conservative financial policies
- Predictable earnings

Weaknesses:
- Negative free cash flow during the next few years
- Capital-intensive operations

Corporate Credit Rating
A/Stable/A-1

Rationale

The ratings on Alberta-based Canadian Utilities Ltd. (CU) reflect Standard & Poor's Ratings Services' opinion of the company's excellent business risk and significant financial risk profiles as conservative financial policies, stable cash flows, and favorable diversity of subsidiary operations all highlight. In our view, the substantially negative free cash flow generation expected in the next few years and capital-intensive operations counterbalance these strengths.

CU, an Alberta-based holding company, engages in both regulated and nonregulated operations that we believe provide a reasonable degree of diversity. Its primary holding, CU Inc. (A/Stable/A-1), is in turn a utility holding company with several wholly owned, primarily Alberta-based, regulated gas and electric subsidiaries. CU's other wholly owned subsidiaries engage in nonregulated activities and include ATCO Power Ltd., ATCO Midstream Ltd., ATCO Australia, and ATCO I-Tek. The company also holds a 24.5% interest in ATCO Structures and Logistics. These largely nonregulated subsidiaries primarily supply electricity and cogeneration steam in several jurisdictions; and provide gas midstream and storage services, project management and technical services, and utility billing and call center services in Alberta. CU had about C$4.6 billion in adjusted consolidated debt outstanding as of Sept. 30, 2011.

CU is public but effectively controlled by ATCO Ltd. (A/Stable/--), which has a 53.0% economic interest in it. Our ratings on CU are the same as our stand-alone assessment of the company. ATCO Ltd. depends highly on CU for its income although it has negligible financial obligations.

Collectively, CU's subsidiaries contribute to what we consider a stable and rising earnings profile. Anchoring earnings is CU Inc.'s contribution, where the size and quality of earnings temper the effect of CU's less stable businesses. We view CU Inc. as a cornerstone of CU. Cash flows represent about 60% of the company's consolidated funds from operations (FFO) and are typically consistent and upward-trending, reflecting growth and investment in CU Inc.'s regulated operations in the Province of Alberta (AAA/Stable/A-1+). ATCO Power contributes about 15%-20% of cash flows and has some variability. It mitigates this through a large portion of contracted output, which offsets its exposure to fuel and off-taker risk normally associated with deregulated power producers. The balance of cash flows comes from ATCO Midstream, its 25% interest in ATCO Structures, ATCO Australia, and ATCO I-Tek. ATCO Midstream provides a more volatile earnings stream largely related to frac spread exposure. ATCO Australia's key asset is a regulated gas distribution monopoly held by WA Network

Holdings Pty Ltd. (BBB-/Negative/--). The other subsidiaries have historically provided a stable earnings source, but it is somewhat more difficult to predict earnings with the same confidence due to less entrenched competitive positions.

CU Inc. is capitalized with leverage of about 60%, which is consistent with most regulated utilities in Canada. We do not expect a deviation from this approach in a period of high investment. ATCO Power's project finance assets generally have higher risk and higher leverage. The portfolio of gas-fired project finance assets are long-term contracted assets that have nonrecourse, amortizing debt. Alberta Power (2000) was transferred from CU Inc. to ATCO Power on Oct. 2, 2010, and is capitalized consistent with its lower business risk profile. ATCO Power debt levels for the remaining, higher risk, subsidiaries are marginal, in our opinion. CU has about C$140 million in long-term debt at the holding company level, and C$705 million in preferred shares at Sept. 30, 2011. Still, we believe that significantly more debt at the holding company could adversely affect the ratings.

Counterbalancing these strengths, in our view, is negative discretionary free cash flow that CU expects for the next few years. We expect that cash dividends and receipts from the company's subsidiaries will not cover cash outflows (primarily common and preferred dividends) in the next few years, and that it will have to draw on cash reserves and issue additional debt. This situation primarily relates to major capital expenditures in regulated assets at CU Inc. and the need for equity injections into that subsidiary.

Liquidity

Our short-term and commercial paper ratings on CU are 'A-1'. We believe the company has adequate consolidated liquidity as described under our criteria. Our assessment of the company's liquidity profile incorporates the following expectations and assumptions:

- We expect CU's consolidated sources over uses to exceed 1.2x during the next six months, and we expect sources to exceed uses even in the unlikely event that EBITDA declines by 15%.
- The company will continue to have solid relationships with its banks, a generally high standing in credit markets and generally very prudent risk management.
- CU's sources of liquidity include cash of about C$900 million (including proceeds from a recent C$700 million debt issuance at CU Inc.), available committed credit lines of about C$1.7 billion (including recent increases of C$600 million at CU Inc. and C$200 million at CU), and FFO of C$400 million-C$500 million in the next six months.
- Liquidity uses include maturities of about C$300 million, capital spending of about C$1 billion during the next six months (primarily at its regulated utilities) and dividends of C$200 million-C$300 million
- As of Sept. 30, 2011, the company was in compliance with all of its covenants.

Outlook

The stable outlook reflects our continued expectations of operational consistency and gradual earnings growth at CU's primary subsidiaries. The ratings, however, could face stress should the company fail to execute its large capital expenditure program in the next few years, or should it materially increase debt directly at the holding company level. The stable outlook on CU also reflects the stable outlook on the ATCO group. We view consolidated adjusted FFO-to-debt of 20% at ATCO Ltd. as a key threshold associated with the ratings, and note that performance is forecast to face stress. Given that we expect credit metrics to fall below this level, primarily as a result of the significant capital expenditure in Canadian regulated utilities we are unlikely to take a positive rating action. However, we note the weakness in credit metrics and our expectation of a return to a FFO-to-debt above 20%. Sustained performance below this level could lead to a negative rating action.

Business Description And Structure

CU is a holding company with five primary subsidiaries.

- CU Inc: A holding company with 100% ownership of three regulated utilities operating primarily in Alberta. It accounts for about 60% of CU's consolidated FFO;
- ATCO Power: A holding company with interests in 14 natural gas-fired and hydroelectric projects in Canada and the U.K., and includes APL 2000. It accounts for 15%-20% of consolidated FFO;
- ATCO Midstream: Provides contracted natural gas storage in Alberta, natural gas processing in Alberta and Saskatchewan, and natural gas liquid extraction in Alberta;
- ATCO I-Tek: This nonregulated business provides business support services to companies; and
- ATCO Australia: It is anchored by a regulated gas distribution monopoly in Western Australia and includes three gas generating facilities.

The company also holds a 25% interest in ATCO Structures and Logistics, which is involved in manufacturing, logistics, and noise abatement.

Most of the company's debt is at CU Inc., ATCO Power, and ATCO Australia. These subsidiaries have financed their operations with debt that is nonrecourse to CU. The company itself has just C$140 million in direct recourse debt and C$705 million in preferred shares. Debt at the holding company is primarily serviced by dividends from its operating companies.

Rating Methodology

Influencing our ratings on CU is the credit quality of the primary subsidiary, CU Inc. and of its other subsidiaries. The dividends flowing to CU from CU Inc. are effectively subordinated to the debt service at CU Inc. The diversity of cash flows from other subsidiaries and the low amount of leverage held directly at CU supports the ratings at the 'A' level.

Excellent Business Risk Profile

CU Inc.

CU Inc. is a utility holding company with several wholly owned, primarily Alberta-based, regulated electric and gas, subsidiaries, including ATCO Electric, ATCO Gas and ATCO Pipelines. ATCO Electric provides electricity transmission and distribution to more than 200,000 customers in east-central and northern Alberta as well as numerous communities in the Yukon and Northwest Territories. ATCO Gas provides regulated gas distribution throughout Alberta, including its two major city centers, Calgary and Edmonton; and the Lloydminster area of Saskatchewan. ATCO Pipelines engages in low-risk, regulated, gas transportation.

We believe CU Inc.'s credit strengths include its low-risk, monopoly-like businesses; and supportive cost-of-service/rate of return regulation. The Alberta Utilities Commission (AUC) regulates the bulk of the company's businesses, which are in Alberta. Although there has been some lag on rate-case approvals, the regulation is generally favorable, in our opinion, as it is consistent and has had low incidences of cost disallowances. Rates of return and deemed equity layers are somewhat low compared with those of global peers, but are similar to those of other Canadian utilities.

ATCO Midstream

This company provides three primary services. It operates natural gas storage facilities and contracts this storage to third parties. It extracts natural gas liquids from natural gas through its interest in straddle plants and sells the liquids to third parties. And it has some small natural gas processing facilities. These operations are in western Canada.

Despite operating in a somewhat competitive sector, the company manages the operations to reduce earnings variability. ATCO Midstream contracts out the storage to third parties and does not take any commodity price risk itself. The natural gas liquids business is volatile and tends to perform best when natural gas prices are relatively low compared with oil prices. The gas gathering and processing business is relatively stable but fairly competitive. ATCO Midstream is capitalized with modest debt levels that further reduce CU's risk.

ATCO Power

ATCO Power is a holding company with a portfolio of natural-gas fired and hydroelectric projects in Canada and the U.K. Its interest in these projects ranges from 25%-80%. It funds most of them with nonrecourse project-financing debt. The plants under operation are fairly young and are efficient, in our opinion. A large proportion of the power and steam from these projects are sold under contracts with strong off-takers which substantially limits earnings volatility.

Despite these assets' solid earnings profile, we believe ATCO Power's dividend stream is quite low but improving. The company is using a large proportion of operating cash flow to reduce debt at the projects.

ATCO I-Tek

ATCO I-Tek is a business services provider based in Alberta. It primarily provides billing support and customer care solutions (such as call centers). This business has what we view as fairly low barriers to entry and is competitive. I-Tek has, however, developed a leadership position in the Alberta utility business. We believe it has been, and should continue to be, a solid and stable earnings contributor to CU.

APL 2000

APL 2000 operates electricity generation assets governed by legislated power purchase agreements (PPAs) that the AUC approves of and mirror cost-of-service regulation for the assets' expected life. The PPAs for Battle River (Units 3 and 4) expire Dec. 31, 2013. Proposed regulations could limit the life of coal-fired units to 45 years or link closure to the expiry of their PPAs, whichever is longer. When the PPAs expire, the units will be 44 and 38 years old, respectively.

ATCO Australia

This company consists primarily of the recent acquisition, WA Gas Networks Pty Ltd (WAGN), and three generating facilities. ATCO Australia acquired WAGN's parent, WA Network Holdings, in July for about A$1 billion, including the assumption of about A$644 million of debt. WAGN is a regulated gas distribution monopoly with an excellent business risk profile that is supported by its business as a regulated natural gas distribution monopoly. We note that the company has weaker credit metrics, leading to a mild deterioration in CU and ATCO Ltd.'s consolidated credit metrics. The acquisition offers modest diversification benefits through both its geographical and regulatory diversification; however, diversification benefits are limited by the acquisition's relative size compared to CU's current businesses.

Stable profitability

We believe CU's profitability remains fairly stable, given that 40%-50% of earnings come from the regulated operations at CU Inc. Profitability of these regulated operations is primarily a function of the regulatory regime governing electricity rates; however, the Alberta PPAs in power generation have modest allowed returns compared with those of global peers. The stability of CU's profitability also receives support from the diverse nature of the company's portfolio of nonregulated operations, its hedging practices, and long-term contracts that mitigate the impact of variations in gas and electricity prices or demand, coal prices, and foreign exchange or interest rate fluctuations. Nevertheless, earnings from CU's individual nonregulated businesses face some variability due to competitive and market risk.

Moderate Financial Policy

CU's moderate financial policies reflect our view of the following considerations:

- We believe regulated utilities (CU Inc.) will be capitalized approximately in line with regulatory capital structure allowances--about 60%, including preferred shares as 50% debt.
- Unregulated power projects are financed with debt amortizing annually; CU normally doesn't guarantee that debt.
- Other unregulated businesses typically have just small debts associated with their capital structure.
- The company uses some leverage at the holding company; it has C$140 million of debt and C$705 million in preferred shares.
- It does not typically guarantee subsidiaries' debt. It does guarantee a C$100 million credit line at ATCO Midstream and C$100 million in debt at a power subsidiary.
- CU is fairly conservative, in our view; it has been relatively cautious in making acquisitions and its only goodwill on the balance sheet relates to the WAGN acquisition. It is publicly listed, so there is pressure to maintain at least a constant dividend. This can cause the company to sustain draws on its cash balances during periods of capital expansion.

Significant Financial Risk Profile

Accounting

CU prepares its audited financial statements in accordance with International Financial Reporting Standards. Before Jan. 1, 2011, the company prepared its financial statements in accordance with Canadian generally accepted accounting principles. Effectively, all liabilities of the company's subsidiaries are consolidated at the company level.

The consolidated financial statements present some challenges to our analysis. In particular, it is difficult to track individual cash flows between the parent and subsidiaries (either in the form of equity injections from the parent or dividends from the subsidiaries).

For these reasons, we have received supplementary deconsolidated financial information from management that better illustrates the operating results of the primary operating subsidiaries and the dividends that flow to CU from the subsidiaries.

Cash flow adequacy

On a deconsolidated basis, we expect CU to gain sufficient dividend flows and other cash distributions from its subsidiaries to cover interest and preferred dividends. The company, however, pays substantial cash dividends, and there will likely be insufficient residual cash flows (after making equity injections in CU Inc. payment of debt service and preferred dividends) to pay them; it plans to cover the deficiency with cash balances (which are diminished following the Australian acquisition) and new debt. This is likely to last several years because its primary subsidiaries are undertaking material capital expenditures related to growth. Consolidated cash flow coverages are weak but acceptable, in our view.

Capital structure

CU has low deconsolidated debt levels. It has just C$140 million in debt directly, but it has C$705 million in preferred shares. It has raised preferred shares on behalf of CU Inc. (the proceeds being mirrored to CU Inc.) but we expect that CU Inc. will raise its preferred equity directly.

Giving preferred shares 50% equity treatment, the company's consolidated leverage is 55%. Although we believe this is somewhat high, it largely reflects CU Inc.'s utility-like leverage.

Table 1

Canadian Utilities Ltd.--Peer Comparison

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31, 2010--			
(Mil. C$)	**Canadian Utilities Ltd.**	**ATCO Ltd.**	**Fortis Inc.**	**Emera Inc.**
Rating as of Nov. 23, 2011	A/Stable/A-1	A/Stable/--	A-/Stable/--	BBB+/Stable/--
Revenues	2,657.2	3,445.4	3,664.0	1,553.7
EBITDA	1,129.1	1,291.3	1,177.2	588.3
Net income from continuing operations	478.5	297.9	330.0	202.2
Funds from operations (FFO)	755.1	942.1	720.6	344.5
Capital expenditures	766.5	869.5	954.9	505.0
Free operating cash flow	(0.0)	70.1	(236.3)	(80.2)
Discretionary cash flow	(211.8)	(128.3)	(474.8)	(221.6)
Cash and short-term investments	539.6	647.7	109.0	9.4
Debt	3,978.1	3,892.4	6,599.9	3,817.8
Equity	3,900.0	4,349.6	4,024.5	1,447.2
Adjusted ratios				
EBITDA margin (%)	42.5	37.5	32.1	37.9
EBITDA interest coverage (x)	4.1	4.9	3.0	3.2
EBIT interest coverage (x)	3.1	3.5	2.0	2.0
Return on capital (%)	10.3	10.6	7.1	7.1
FFO/debt (%)	19.0	24.2	10.9	9.0
Free operating cash flow/debt (%)	(0.0)	1.8	(3.6)	(2.1)
Debt/EBITDA (x)	3.5	3.0	5.6	6.5
Total debt/debt plus equity (%)	50.5	47.2	62.1	72.5

Table 2

Canadian Utilities Ltd.--Financial Summary

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2010**	**2009**	**2008**	**2007**	**2006**
Rating history	A/Stable/A-1	A/Stable/A-1	A/Stable/A-1	A/Stable/A-1	A/Stable/A-1
Revenues	2,657.2	2,584.0	2,778.9	2,404.9	2,430.4
EBITDA	1,129.1	1,113.2	1,117.7	986.1	1,030.7
Net income from continuing operations	478.5	507.3	445.6	421.0	359.7
Funds from operations (FFO)	755.1	819.9	799.6	740.0	667.5
Capital expenditures	766.5	774.7	904.8	616.8	496.5
Dividends paid	211.8	197.5	183.1	174.0	194.6
Debt	3,978.1	4,045.2	3,846.8	3,591.6	3,518.7
Preferred stock	430.0	392.5	312.5	312.5	318.3
Equity	3,900.0	3,474.5	3,014.9	2,786.3	2,617.4
Debt and equity	7,878.0	7,519.8	6,861.7	6,377.9	6,136.1
Adjusted ratios					
EBITDA margin (%)	42.5	43.1	40.2	41.0	42.4
EBIT interest coverage (x)	3.1	3.1	3.0	2.9	2.9
FFO interest coverage (x)	3.5	3.8	3.9	3.8	3.4
FFO/debt (%)	19.0	20.3	20.8	20.6	19.0
Discretionary cash flow/debt (%)	(5.3)	(5.4)	(7.8)	(2.1)	(1.3)
Net cash flow/capex (%)	70.9	80.4	68.1	91.8	95.2
Debt/debt and equity (%)	50.5	53.8	56.1	56.3	57.3
Return on capital (%)	10.3	11.1	11.6	10.9	11.9
Return on common equity (%)	13.1	15.3	15.0	15.6	13.8
Common dividend payout ratio (unadjusted; %)	43.7	38.0	40.4	40.5	54.6

Table 3

Reconciliation Of Canadian Utilities Ltd. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2010--									
Canadian Utilities Ltd. reported amounts	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	3,404.7	4,135.2	2,657.2	1,100.1	764.6	235.9	762.2	762.2	233.5	756.1
Standard & Poor's adjustments										
Operating leases	80.8	N/A	N/A	5.6	5.6	5.6	14.4	14.4	N/A	10.4
Intermediate hybrids reported as equity	430.0	(430.0)	N/A	N/A	N/A	21.8	(21.8)	(21.8)	(21.8)	N/A
Postretirement benefit obligations	N/A	194.8	N/A	14.8	14.8	5.5	16.7	16.7	N/A	N/A

Table 3

Reconciliation Of Canadian Utilities Ltd. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$) (cont.)										
Share-based compensation expense	N/A	N/A	N/A	4.2	N/A	N/A	N/A	N/A	N/A	N/A
Asset retirement obligations	62.6	N/A	N/A	4.4	4.4	4.4	(5.0)	(5.0)	N/A	N/A
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	N/A	59.0	N/A	N/A	N/A	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(11.4)	N/A	N/A
Total adjustments	573.4	(235.2)	0.0	29.0	83.8	37.3	4.3	(7.1)	(21.8)	10.4
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	3,978.1	3,900.0	2,657.2	1,129.1	848.4	273.2	766.5	755.1	211.8	766.5

N/A--Not applicable.

Related Criteria And Research

- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- Alberta Government's Decision To Review Infrastructure Projects Is Credit Neutral For Five Companies, Oct. 24, 2011
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011

Ratings Detail (As Of November 23, 2011)	
Canadian Utilities Ltd.	
Corporate Credit Rating	A/Stable/A-1
Commercial Paper	
Local Currency	A-1
Canadian National Scale Commercial Paper Rating	A-1(MID)
Preferred Stock (8 Issues)	BBB+
Canadian Preferred Stock Rating (8 Issues)	P-2(High)
Senior Unsecured (1 Issue)	A
Corporate Credit Ratings History	
07-Jan-2004	A/Stable/A-1
05-Mar-2003	A+/Watch Neg/A-1
12-Nov-2002	A+/Negative/A-1
Business Risk Profile	Excellent
Financial Risk Profile	Significant

Ratings Detail (As Of November 23, 2011) **(cont.)**

Related Entities	
ATCO Ltd.	
Issuer Credit Rating	A/Stable/--
Preferred Stock (1 Issue)	BBB+
Canadian Preferred Stock Rating (1 Issue)	P-2(High)

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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April 18, 2012

Emera Inc.

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Table Of Contents

Emera Inc.

Major Rating Factors

Corporate Credit Rating
BBB+/Negative/--

Strengths:

- Relatively diversified portfolio of low-risk monopoly electricity generation, transmission, and distribution businesses
- Stable, regulated cash flows with generally supportive regulatory regimes and limited commodity price and volume exposure
- Focused growth strategy

Weaknesses:

- Consolidated financial and cash flow measures weak for the ratings
- Timing difference between large-scale capital deployment and cash flow generation
- Integration challenges with newer acquisitions

Rationale

The ratings on Emera Inc. reflect Standard & Poor's Ratings Services' opinion of the company's strong business risk profile and significant financial risk profile. Our business risk assessment reflects the stable and predictable regulated cash flows from Emera's utility operations, with what we believe to be a focused growth strategy. The financial risk profile reflects our view of consolidated financial and cash flow measures that are weak for the ratings. These metrics could come under further stress as a consequence of the large-scale capital investment and the lag from expenditure until the time that cash flow with respect to this investment is realized.

Emera is a utility holding company with interests in the Maritimes, the northeastern U.S., and Caribbean. The company organizes its operations into five primary segments:

- Nova Scotia Power Inc. (NSPI; BBB+/Negative/--);
- Maine utility operations (which comprises Bangor Hydro Electric Co. [BHEC; not rated] and Maine and Maritimes Corp. [MAM; not rated]);
- Caribbean utility operations (which comprises an 80% ownership interest in Light & Power Holdings Ltd. [LPH]and its wholly owned subsidiary, Barbados Light & Power Co. Ltd. [BLPC]; and a 80.4% direct and indirect ownership interest in Grand Bahama Power Co. Ltd. [GBPC]);
- Pipelines (which comprise Emera Brunswick Pipeline Co. Ltd. [EBPL] and a 12.9% interest in Maritimes & Northeast Pipeline [M&NP]); and
- Services, renewable sources, and other investments.

The cash flow and earnings from its primary regulated businesses, NSPI, Maine utilities, and Caribbean utilities, which together represent approximately 89% of consolidated revenue, underpin our assessment of Emera's business risk profile. In addition, NSPI benefits from its monopoly position as the principal electricity supplier in the Province of Nova Scotia (A+/Stable/A-1+), and the Maine and Caribbean utility operations also have monopolistic market positions. Moreover, we expect the fuel-adjustment mechanism (FAM) for NSPI (which accounts for 60% of Emera's consolidated revenue) to continue to allow the utility to pass through fuel costs into rates with only modest delay. The companies that make up the Caribbean operations also have an FAM. The Maine utility segment includes transmission and distribution assets. Further supporting the business risk profile are the nonregulated pipeline businesses, which largely have contracted revenues. EBPL transports natural gas under a long-term take-or-pay commitment from Repsol Energy Canada Ltd., which is backed by a guarantee from its parent, Repsol-YPF S.A. (BBB/Positive/A-2) that allows it to earn a moderate-but-stable rate of return.

We believe supportive, cost-of-service regulation underpins the majority of Emera's cash flows. Furthermore, regulated utility customers provide what we consider a solid revenue base. About 70% of the company's regulated sales revenues come from its diversified residential and commercial customer base, providing stability for its regulated cash flows. Notwithstanding minimal energy demand growth in Nova Scotia, Maine, or the Caribbean, organic growth opportunities exist as Emera executes its growth strategy.

The company has made or announced a number of recent investments, most notably an increase in its holdings of Algonquin Power and Utilities Corp. (not rated), and its potential participation in the Lower Churchill Falls hydro-electric project and its joint venture with First Wind Holdings LLC (not rated). This is in addition to several investments in 2010, mostly in regulated utilities. Emera has articulated a strategy that focuses on using acquisition and development activities in an integrated way to address the movement from carbon-based electricity to noncarbon-based electricity. This shift is most notably found in Nova Scotia's provincial legislation, which has targets for renewable energy requirements of 25% by 2015 and 40% by 2020. However, we view this capital expenditure in a regulatory context, which provides limited cash flow relief during construction of multiyear projects, and a balanced-but-measured perspective on yearly rate applications leading to large rate increases.

Emera's proposed involvement in the Lower Churchill Falls project will be through two avenues. The first will be its 29% participation with Nalcor Energy on the Labrador-Island Transmission Link, a 900-megawatt (MW) capacity transmission line from Labrador to Newfoundland. The second will be the Maritime Transmission Link, a 500-MW capacity transmission line (including a 180-kilometer undersea link from Newfoundland to Nova Scotia), which the company will develop independently. Through these two projects, Emera will be able to integrate and further develop its Maritime and Northeastern U.S. platforms.

The company's financial risk profile is significant, in our view, with financial measures that we consider to be weak for the ratings. Somewhat offsetting the weaker credit measures is the significant portion of cash flow that comes from regulated utilities supported by an FAM that we expect will continue to display fairly low volatility. However, in the near-to-medium term, it is possible that given the regulatory regime, the credit metrics could suffer some deterioration.

Finally, while the Caribbean operations represent an opportunity to invest in developing a lower carbon strategy, in the near term, there might be some operational challenges while the company moves the operations to standards more consistent with those in a North American utility.

Liquidity

We believe that Emera's liquidity is adequate as per our criteria. We expect that in the next 12 months, projected sources of liquidity, mainly funds from operations (FFO) and revolver availability, will cover projected uses (mainly capital expenditures and common dividends) 2.6x. Moreover, the company's liquidity benefits from its high standing in the credit markets and, in our view, solid relationship with its bank lending group.

This evaluation considers the following factors:

- We forecast FFO to be approximately C$525 million.
- We also forecast sustaining capital expenditure to be approximately C$225 million.
- In addition, we forecast dividends to preferred and common shareholders to total approximately C$200 million.
- Emera has a C$700 million revolving credit facility expiring in June 2015.
- NSPI has an additional C$500 million bank facility expiring in June 2015.
- BHEC has access to US$80 million in credit facilities that mature in September 2013.
- Total availability under all credit facilities as of Dec. 31, 2011, is C$634 million.

We believe Emera's consolidated near-term debt maturities are light and manageable, with C$28 million of debt repayments in 2012. There are no parent-level long-term debt maturities until 2013.

Outlook

The negative outlooks on both Emera and NSPI reflect our expectation of the heightened regulatory risk due to the potential upward pressure on rates due to expected development projects that the company is pursuing and the impact on cash flow. We believe it is possible that the company could suffer near-to-medium-term deterioration in its credit metrics. This will depend in part on the regulatory response to the capital projects, the timing of the projects' capital deployment, and the capital structure management uses. We expect Emera to maintain an FFO-to-total debt of more than 12% and debt-to-EBITDA equal to or less than 6x. We could take a negative rating action if we expect the company to breach this target on a sustained basis or invest in assets with greater earnings variability or business risk; or if it does not continue to exhibit stable operating performance. Conversely, although we do not expect it during our two-year outlook horizon, we could take a positive rating action if the company adopts a more conservative financial policy.

Corporate Structure And Rating Methodology

Emera is structured as a holding company and accounts for its significant subsidiaries including NSPI on a consolidated basis. All major subsidiaries have separate management teams and boards of directors and thus there is high degree of operating separation between Emera and it subsidiaries. The major subsidiaries generally raise their own debt and Emera does not guarantee its subsidiaries' debt. However, we still consider the financial linkage between the parent and its subsidiaries as high, given the relative importance of each of the major subsidiaries to Emera.

We believe that Emera would likely support its subsidiaries through a wide range of adverse operating conditions. Given the existence of double leverage common in a holding company structure, we do examine credit metrics from a deconsolidated perspective. However, in general we consider consolidated credit measures to assess overall group leverage and cash flow-generating ability in our evaluation.

Strong Business Risk Profile

Benefits of business diversity and predictable cash flow generation from its main regulated utilities underpin Emera's strong business profile, in our opinion. Generally speaking, these utilities operate under supportive regulatory environments. These environments are the traditional cost-of-service model and (in the case of NSPI and the Caribbean utilities operations) include an FAM that supports predictable earnings and insulates them from commodity-price risk and demand fluctuation.

Emera organizes itself into five primary segments.

Nova Scotia Power Inc.

NSPI is a fully integrated regulated electric utility that provides generation, transmission, and distribution service in Nova Scotia. The company owns 2,374 MW of generating capacity, of which more than half is coal-fired. Hydro and wind account for approximately 20%. NSPI owns approximately 5,000 kilometers of transmission facilities and 26,000 kilometers of distribution facilities.

NSPI is a public utility and is regulated by the Nova Scotia Utility and Review Board. NSPI is a cost-of-service utility and as such, regulated electricity rates are set to enable it to recover all prudently incurred costs (including fuel) and earn a prescribed return on equity (ROE). The company operates as a monopoly in its service area. The approved ROE target range is 9.1%-9.5% based on maximum actual equity of 40%. We forecast NSPI will generate approximately C$350 million-C$400 million in FFO during 2012.

Maine utility operations

The Maine utility operations include BHEC, Maine Public Service Co. (MPS), and MAM, MPS' parent. BHEC and MPS are both transmission and distribution electric utilities, and are regulated by the Maine Public Utilities Commission and the Federal Energy Regulatory Commission. Standard & Poor's believes the State of Maine constitutes a less credit-supportive regulatory environment.

BHEC is the second-largest electric utility in Maine and serves approximately 118,000 customers in eastern Maine. It owns and operates approximately 1,000 kilometers of transmission facilities and 7,200 kilometers of distribution facilities. MPS owns and operates approximately 600 kilometers of transmission facilities and 2,900 kilometers of distribution facilities. BHEC's distribution business operates under a cost-of-service regulatory structure with an ROE of 10.2% on an equity layer of 50%. Its local transmission rates are set annually based on a formula using the previous year's actual transmission investments and expenses, adjusted for current-year forecast transmission investments and expenses. The allowed ROE is 11.14%. The common equity component is based on the previous year's actual average balance. The Independent System Operator-New England manages BHEC's bulk transmission assets as part of a region wide pool of assets. The company recovers the full cost of service based on a regional formula updated each year. The allowed ROE ranges from 11.64%-12.64%, and the common equity component is based on the previous calendar year's average balances.

MPS serves approximately 36,000 customers in northern Maine. It is engaged in the transmission and distribution of electric energy, with a service area of approximately 5,275 square miles covering all of Aroostook County and a portion of Penobscot County. It owns and operates approximately 600 kilometers of transmission facilities and 2,900 kilometers of distribution facilities. Its distribution businesses operate under cost-of-service regulatory structure with ROE of 10.2% on an equity layer of 50%. MPS sets local transmission rates annually based on a formula. The allowed ROE for transmission operations is 10.5% and is based on the previous year's actual common equity balances. The allowed ROE is determined by negotiation with customers every three years.

Caribbean utility operations

The Caribbean operations include an 80% investment in LPH and its wholly owned subsidiary BLP; and a 19.1% indirect interest in St. Lucia Electricity Services. In addition, it has a 50.0% direct and 30.4% indirect interest in GBPC.

BLPC is a vertically integrated utility and the sole provider of electricity on the island of Barbados. It serves approximately 123,000 customers and is regulated by the Fair Trading Commission, Barbados. The government of Barbados has granted BLPC a franchise to produce, transmit, and distribute electricity on the island until 2028. The utility is regulated under a cost-of-service model, with rates set to recover prudently incurred costs (including fuel) of providing electricity service to customers and provide an appropriate return to investors.

GBPC is a vertically integrated utility and the sole provider of electricity on Grand Bahama Island. It serves 19,000 customers and is regulated by Grand Bahama Port Authority, which has granted the utility a licensed, regulated and exclusive franchise to produce, transmit, and distribute electricity on the island until 2054.

Pipeline operations

Pipeline operations comprise Emera's wholly owned EBPL and the company's 12.9% interest in M&NP.

EBPL is a 145-kilometre pipeline delivering natural gas from the Canaport re-gasified liquefied natural gas (LNG) import terminal near Saint John, N.B. to markets in the northeastern U.S. The pipeline transports re-gasified LNG for Repsol Energy Canada under a 25-year firm service agreement. This pipeline connects an LNG facility in New Brunswick to a pipeline at the Canada-U.S. border. Similar to Emera's regulated operations, it is structured to provide a low-but-predictable rate of return. While we believe LNG economics are tenuous in North America, we view Repsol's take-or-pay commitments as supporting earning stability.

M&NP is a 1,400-kilometer pipeline that transports natural gas from offshore Nova Scotia to markets in Maritime Canada and the northeastern U.S.

Services, renewables, and other investments

This sector includes a number of smaller subsidiaries, as follows:

Emera Energy. This consists of Emera Energy Services, a physical energy business that purchases and sells natural gas and electricity and provides related energy asset management services; Bayside Power, a 260-MW gas-fired merchant electricity generating facility in Saint John; and a 50% joint venture interest in Bear Swamp, a 600-MW pumped storage hydro-electric facility in northern Massachusetts. Bear Swamp is equity-accounted.

Emera Utility Services. This is a utility services contractor.

Emera Newfoundland & Labrador Holdings Inc. This is a wholly owned subsidiary of Emera focusing on transmission investments related to the proposed 824-MW hydro-electric generating facility at Muskrat Falls in Labrador.

In addition, Emera owns a 5.82% interest in Algonquin Power (forecast to rise to 25% by the end of 2012), a 49.99% interest in California Pacific Utilities Ventures LLC, and a 37.70% investment in Atlantic Hydrogen Inc. These investments are equity-accounted.

Financial Policy

In our view, Emera seeks to capitalize its regulated subsidiaries in line with regulatory levels. It does not typically guarantee the subsidiaries' debt. However, it has provided financing for a particular asset (the debt it used to finance the Brunswick Pipeline, for example, is at the Emera level).

Profitability measures are comparable with those of similarly rated regulated utilities

The comparable companies are both utility holding companies with a reasonable level of diversity. Emera's somewhat higher operating risk reflects its higher percentage ownership of power generation assets. ATCO Ltd. typically follows conservative financial policies, highlighted by its superior credit measures (see table 1), strong liquidity position, and higher dividend retention policy. Reflecting this is an intermediate financial risk profile compared with that of Emera. Fortis Inc., relative to Emera, has a much larger customer base and better geographic diversification. Historically, the parent's approach was more incremental investments compared with those of Fortis, which seeks out sizable acquisition (its target size would be more than C$750 million) that would have a meaningful impact on its FFO generation. However, the Lower Churchill Falls project is an example of a departure from this strategy for Emera.

Table 1

Emera Inc. -- Peer Comparison

Industry Sector: Electric Utility

	Emera Inc.	Fortis Inc.	ATCO Ltd.
Rating as of April 16, 2012	BBB+/Negative/--	A-/Watch Neg/--	A/Stable/--
Business Risk Profile	Strong	Excellent	Excellent
Financial Risk Profile	Significant	Significant	Significant
	--Fiscal year ended Dec. 31, 2011--		
(Mil. C$)			
Revenues	2,072.9	3,747.0	3,991.0
EBITDA	599.8	1,223.7	1,470.5
Net income from cont. oper.	247.7	364.0	327.0
Funds from operations (FFO)	475.0	771.9	1,247.4
Capital expenditures	482.2	1,053.9	1,540.7
Free operating cash flow	(47.6)	(189.0)	(324.2)
Dividends paid	165.6	183.0	187.5
Discretionary cash flow	(213.2)	(372.0)	(511.7)
Cash and short-term investments	76.9	89.0	768.0
Debt	4,115.0	6,968.3	5,940.2
Preferred stock	139.7	456.0	533.5
Equity	1,684.0	4,279.0	4,129.5
Debt and equity	5,799.0	11,247.2	10,069.7
Adjusted ratios			
EBITDA interest coverage (x)	3.1	3.0	5.0
FFO int. cov. (X)	3.3	2.7	4.9
FFO/debt (%)	11.5	11.1	21.0
Free operating cash flow/debt (%)	(1.2)	(2.7)	(5.5)
Discretionary cash flow/debt (%)	(5.2)	(5.3)	(8.6)
Net cash flow / capex (%)	64.2	55.9	68.8
Debt/EBITDA (x)	6.9	5.7	4.0
Total debt/debt plus equity (%)	71.0	62.0	59 0
Return on capital (%)	6.7	7.1	11.2
Return on common equity (%)	15.6	8.4	14.4

Table 1

Emera Inc. -- Peer Comparison (cont.)			
Common dividend payout ratio (un-adj.) (%)	68.1	64.8	20.2

Significant Financial Risk Profile

Accounting policies are in line with industry norms

Emera prepared its annual and interim financial statements in accordance with U.S. generally accepted accounting principles (GAAP) effective Jan. 1, 2011, and restated its 2010 financial results accordingly. The U.S. GAAP conversion does not affect our view on the company's financial risk profile. In accordance with our criteria, we treat 50% of preferred shares as debt-like obligations. Our adjustment associated with postretirement benefit obligations represents about 9% of total adjusted debt while other adjustments are not material (see table 2).

Table 2

Reconciliation Of Emera Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

--Fiscal year ended Dec. 31, 2011--

Emera Inc. reported amounts	Debt	Shareholders' equity	Revenues	EBITDA	Operating income	Interest expense	Cash flow from operations	Cash flow from operations	Dividends paid	Capital expenditures
Reported	3,519.5	1,731.8	2,072.9	567.5	317.5	169.6	428.1	428.1	172.9	472.1
Standard & Poor's adjustments										
Operating leases	24.4	N/A	N/A	0.9	0.9	0.9	2.4	2.4	N/A	21.0
Intermediate hybrids reported as equity	139.7	(139.7)	N/A	N/A	N/A	7.3	(7.3)	(7.3)	(7.3)	N/A
Postretirement benefit obligations	364.0	(0.0)	N/A	29.3	29.3	4.8	23.0	23.0	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	10.9	(10.9)	(10.9)	N/A	(10.9)
Share-based compensation expense	N/A	N/A	N/A	2.1	N/A	N/A	N/A	N/A	N/A	N/A
Asset retirement obligations	67.4	N/A	N/A	N/A	N/A	N/A	(0.7)	(0.7)	N/A	N/A
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	N/A	31.5	N/A	N/A	N/A	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	40.3	N/A	N/A
Minority interests	N/A	91.9	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	595.5	(47.8)	0.0	32.3	61.7	23.9	6.6	46.9	(7.3)	10.1

Table 2

Reconciliation Of Emera Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$) (cont.)

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	4,115.0	1,684.0	2,072.9	599.8	379.2	193.5	434.7	475.0	165.6	482.2

N/A--Not applicable.

Steady profitability

Profitability and cash flow protection at Emera are largely a function of the capital structure and returns from its regulated subsidiaries. Our ratings continue to factor in a similar level of profitability during the next few years from the subsidiaries. Variances would most likely come from changes in allowed ROE or by cost disallowances.

Operating cash flow has been somewhat less stable, given working capital volatility. Nevertheless, it has been persistently above net income, given the large proportion of noncash expenses.

Capital expenditures

A strategic motivation for the company's capital investment plan is to address the shift from carbon-based electricity to noncarbon-based electricity. This movement is embodied in the Nova Scotia government's targets for renewable energy requirements of 25% by 2015 and 40% by 2020. While we believe that these investments are consistent with Emera's focused strategy and the broader provincial initiative, we expect that they will require a meaningful capital expenditure program from energy policies at both the federal and provincial levels. This will likely spur the need for numerous rate increases that we believe heighten regulatory risk in the Nova Scotia market.

We view the capital expenditure in a regulatory context, which provides limited cash flow relief during construction for multiyear projects and a balanced but measured perspective on yearly rate applications leading to large rate increases. Accordingly, the timing difference between the regulatory asset's development (with the consequential debt) and the commencement of cash flow in the context of heightened regulatory risk could stress financial metrics beyond our target of 12% FFO-to-debt. Although we do not expect the company to proceed with any major capital spend without regulatory support, the degree and nature of regulatory and government support are not clear.

Capital structure

Emera's adjusted total debt-to-total capital as of Dec. 31, 2011, was 71% (66% on a reported basis), which is somewhat higher than the company's financial policies. It has more than C$700 million in debt at the holding company level. A high proportion of this debt relates to the funding of the Brunswick Pipeline.

Table 3

Emera Inc. -- Financial Summary

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31--				
	2011	**2010**	**2009**	**2008**	**2007**
Rating history	BBB+/Stable/--	BBB+/Stable/--	BBB+/Stable/--	BBB/Positive/--	BBB/Stable/--
(Mil. C$)					
Revenues	2,072.9	1,705.1	1,457.0	1,331.9	1,339.5
EBITDA	599.8	543.1	564.8	516.1	563.6

Table 3

Emera Inc. -- Financial Summary (cont.)					
Net income from continuing operations	247.7	193.7	185.2	158.2	165.4
Funds from operations (FFO)	475.0	457.1	342.3	335.5	367.6
Capital expenditures	482.2	515.0	299.3	526.1	249.9
Dividends paid	165.6	137.4	121.2	116.9	107.0
Debt	4,115.0	3,716.6	3,075.0	2,840.5	2,211.9
Preferred stock	139.7	139.7	67.5	130.0	130.3
Equity	1,684.0	1,391.7	1,405.1	1,542.7	1,340.3
Debt and equity	5,799.0	5,108.3	4,480.1	4,383.2	3,552.2
Adjusted ratios					
EBITDA interest coverage (x)	3.1	3.1	3.7	3.6	4.0
FFO int. cov. (x)	3.3	3.4	3.1	3.2	3.4
FFO/debt (%)	11.5	12.3	11.1	11.8	16.6
Discretionary cash flow/debt (%)	(5.2)	(3.0)	(3.5)	(13.6)	(0.1)
Net cash flow/Capex (%)	64.2	62.1	73.9	41.6	104.3
Debt/debt and equity (%)	71.0	72.8	68.6	64.8	62.3
Return on capital (%)	6.7	6.8	7.8	8.5	10.6
Return on common equity (%)	15.6	11.7	9.7	8.4	10.0
Common dividend payout ratio (un-adj.) (%)	68.1	72.2	65.9	74.9	66.0

Ratings Detail (As Of April 18, 2012)	
Emera Inc.	
Corporate Credit Rating	BBB+/Negative/--
Preferred Stock	BBB-
Canadian Preferred Stock Rating	P-2(Low)
Senior Unsecured	BBB
Corporate Credit Ratings History	
30-Mar-2012	BBB+/Negative/--
14-Sep-2009	BBB+/Stable/--
25-Nov-2008	BBB/Positive/--
Business Risk Profile	Strong
Financial Risk Profile	Significant
Related Entities	
Nova Scotia Power Inc.	
Issuer Credit Rating	BBB+/Negative/--
Commercial Paper	
Canadian National Scale Commercial Paper Rating	A-1(LOW)
Preferred Stock	BBB-
Canadian Preferred Stock Rating	P-2(Low)
Senior Unsecured	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

STANDARD & POOR'S

Global Credit Portal
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December 15, 2011

Enbridge Inc.

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Table Of Contents

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Enbridge Inc.

Major Rating Factors

Strengths:

- Strong competitive position in liquids transportation and natural gas distribution
- Long-term, predictable cash flows, with limited commodity exposure and supportive regulation
- Conservative project management and investment criteria

Weaknesses:

- High leverage

Corporate Credit Rating
A-/Stable/--

Rationale

The ratings on Enbridge Inc. reflect Standard & Poor's Ratings Services' view of an excellent business risk profile, which the strong market position of the company's core liquids pipelines and gas distributions businesses, its significant long-term and regulated cash flows, and its conservative approach to risk management all support. In our opinion, the financial risk profile that we view as significant, reflecting high leverage, offsets these strengths.

Enbridge is a holding company with wholly and partially owned subsidiaries that focus primarily on owning and operating natural gas and oil pipelines in North America. The company's subsidiary, Enbridge Pipelines Inc. (EPI; A-/Stable/--), undertakes crude oil transportation while subsidiary Enbridge Gas Distribution Inc. (EGD; A-/Stable/--) leads its gas distribution businesses. Liquids pipelines provide about 50% of the group's adjusted earnings, and Enbridge Gas and returns from other gas distribution assets and services represent approximately 20%. Sponsored investments provide about 20% of earnings while gas pipelines, processing, and energy services make up the rest. Enbridge Inc. had C$14.8 billion in consolidated debt (Standard & Poor's-adjusted) at Sept. 30, 2011.

Enbridge Pipelines operates the world's longest crude oil and liquids pipeline: the Enbridge System in Canada and the Lakehead System in the U.S. It owns the Enbridge System, with one of Enbridge's sponsored investments, Enbridge Energy Partners L.P. (EEP; BBB/Stable/A-2), owning the Lakehead system. The Enbridge System is the dominant pipeline out of Canada's largest oil-producing region. We believe the Enbridge System will benefit from the positive near-to-medium-term supply fundamentals for crude oil, with sustainability of pipeline throughput supported by growth in liquids supply from Alberta oil sands projects. The limited alternatives for transporting material volumes of western Canadian crude production out of the region, typically long lead times associated with new pipeline projects and attractive netbacks to producers, all support the company's competitive position. On July 1, 2011, the company began operating the mainline under a 10-year competitive toll settlement (CTS), which marginally increased its business risk profile.

Enbridge Gas is the largest natural gas distributor in Canada, serving about 2 million customers in central and eastern Ontario. Its monopoly position supports its excellent business risk profile. The company has one of the most attractive gas utility franchises in Canada, characterized by favorable growth prospects, a high population density, and a fair regulatory system. We believe ongoing strong demand for natural gas from its growing customer base in the near-to-medium term will continue to enhance its business risk profile.

Enbridge's regulated and long-term contracted cash flows support its business position, generating about 95% of 2010 earnings. The majority of earnings come from cost-of-service utilities, long-term take-or-pay pipeline contracts, or tolling arrangements that either provide throughput protection or relatively predictable volumes in the near-to-medium term. The long-term nature of the contracted cash flows and regulated returns provides cash flow stability and security such that Standard & Poor's expects relatively low levels of volatility in forecast earnings and cash flows in the next few years.

We believe the company's conservative approach to risk management is a credit strength. Enbridge assumes minimal commodity price, has limits on its volume exposure, and it limits its financial risk through hedging. Its ownership and operation of a number of segments of the energy delivery value chain enhance its strategic position. Although we believe the company remains aggressive in its growth appetite, its operational risk appetite is limited, because it generally focuses on low-risk gas networks and liquids pipelines or has some risk mitigation through cost pass through mechanisms embedded in its contracts. In our view, its investments in complementary and vertically integrated assets enhance, to a degree, the strategic importance of its core assets and provide further growth opportunities. In the past few years, Enbridge has demonstrated its ability to execute several large capex projects, including Southern Lights and Alberta Clipper, on time and on budget, reducing execution risk. The bulk of the company's ever-increasing capex plans are consistent with its business risk profile.

We expect Enbridge's consolidated credit metrics to remain at the low end of the spectrum for the ratings, with some headroom over the 13% funds from operations (FFO)-to-debt floor we have associated with the ratings. Forecast FFO to debt is 13%-15%. At Dec. 31, 2010, FFO-to-debt was 13.8% up slightly from 13.3% a year earlier. Large, long term capital projects put pressure on metrics because debt service commitments flow from the partial debt financing of new pipelines. Enbridge continues to increase its capital program, which we believe will exceed C$5 billion in 2012, although in general the projects are smaller than before. We believe the recent preferred share issuance, asset dropdowns, and reductions in the ownership stakes of sponsored investments establishes a precedent that the company might continue to implement in order to support credit metrics.

Liquidity

Our short term and commercial paper ratings on Enbridge are 'A-1'. We believe the company has adequate liquidity as per our criteria. Our assessment incorporates the following expectations and assumptions:

- We expect Enbridge's liquidity sources over uses to exceed 1.2x during the next six months, and we expect sources to exceed uses even in the unlikely event that EBITDA declines 15%.
- The company will continue to have solid relationships with its banks, a generally high standing in credit markets and generally very prudent risk management.
- Consolidated liquidity sources include FFO of more than C$1 billion in the next six months, about C$450 million of unrestricted cash and cash equivalents as of Sept. 30, 2011, and undrawn committed facilities of about C$3.5 billion.
- Uses of liquidity in the next six months include expected capital spending of about C$2.5 billion, and about C$500 million of shareholders distributions and debt maturities.
- We expect Enbridge's to be discretionary cash flow negative for the next several years as it continues its ongoing capital program.

As of Sept 30, 2011, the company complied with all of its covenants.

Outlook

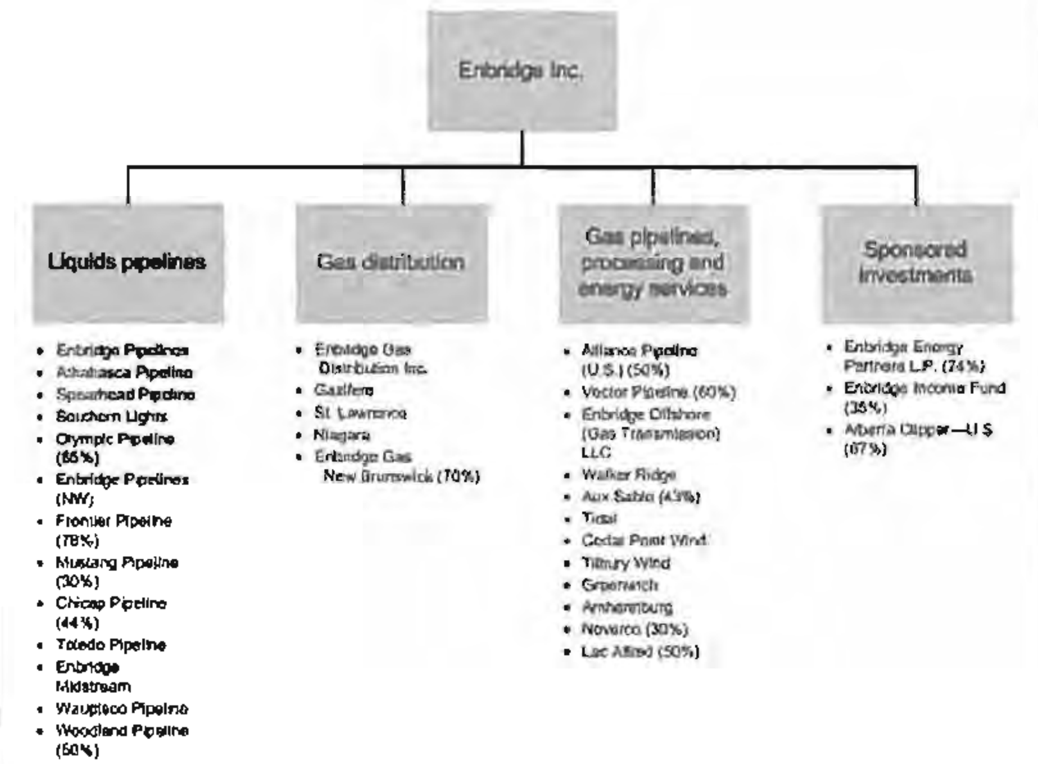
The stable outlook on EI reflects our view that credit metrics, while forecast to be weak for the ratings are expected to remain above established thresholds. A deterioration in adjusted last-12-month FFO-to-debt below 13% would likely result in a downgrade. In addition, deterioration in the business risk profile, either through a single event or a more gradual shift, could lead us to lower the ratings. Without a material reduction in leverage, an upgrade is unlikely.

Business Description

Enbridge is a large, diverse holding company (see chart). Its operations center largely on transporting crude oil south from Canada to the U.S. Midwest and with the Seaway pipeline acquisition and reversal to the gulf coast; transporting natural gas to the U.S. Midwest, Gulf coast, and eastern Canada; and distributing natural gas in Ontario, Quebec, and New Brunswick. The company retains a 23.8% ownership interest in EEP, a U.S. master limited partnership that transports liquid petroleum products and natural gas, and owns natural gas gathering, treatment, and processing operations in the U.S. Enbridge also holds a 35% interest in Enbridge Income Fund (EIF; not rated), which partially owns Alliance Pipeline L.P. (senior secured debt rating: BBB+/Stable). Enbridge also owns 100% of Enbridge Energy L.P. (EELP; not rated) through which it funds 67% of the Alberta Clipper pipeline's equity. It manages the day-to-day operations and strategic direction of EEP, EIF, and EELP.

Enbridge is a publicly traded company. There are four primary business units: liquids pipelines, which Enbridge Pipelines dominates; natural gas delivery and services, which Enbridge Gas dominates; gas pipelines, processing and energy services, which themselves include the company's Gulf of Mexico offshore assets and interests in the Alliance and Vector pipelines; and sponsored investments, specifically EEP, EIF, and EELP. The company also has a corporate segment.

Enbridge Inc.—Organizational Chart



Note: All subsidiaries are wholly owned unless otherwise noted. Economic interests in Enbridge Energy Partners and Enbridge Income Fund are about 35% and 69%, respectively.

Rating Methodology

The ratings on Enbridge and its subsidiaries reflect Standard & Poor's consolidated rating methodology. The ratings also reflect our view of a consolidated business risk profile that captures the business risk and cash flow of the company's various subsidiaries, including its regulated operations. The methodology is appropriate given the intercompany investments between Enbridge and its wholly owned subsidiaries, Enbridge Pipelines and Enbridge Gas. As a result, the corporate credit ratings on these subsidiaries are the same as those on the parent.

Enbridge issues debt at its subsidiaries as well as directly at the holding company level. It does not typically guarantee its subsidiaries' debt. We do not structurally subordinate the debt at Enbridge because we view that substantial diversity of subsidiary holdings available to service the debt at the holding company as offsetting the structural subordination. We do, however, rate Enbridge's preferred stock two notches lower, at 'BBB', to reflect its weaker claim to debt in bankruptcy.

Intercorporate financial links remain strong, in our view. At Sept. 30, 2011, EPI had more than C$4 billion of loans to and from affiliates on an asset base of about C$15 billion. EGD had more than C$1.2 billion of loans and investments in affiliates on an asset base of about C$7.0 billion.

Excellent Business Risk Profile

Liquids pipelines about 50% of earnings

Enbridge System. The Enbridge System consists of the Canadian portion of the mainline system that transports oil from Alberta to the U.S. and eastern Canada. In our opinion, the Enbridge system continues to benefit from an excellent competitive position.

Enbridge system has a capacity of more than 2 million barrels per day (mmbpd) and is currently and forecast to be the leading transporter of crude oil out of the worlds largest reserve basins. The product shipped through the system is the single largest source of crude oil to the world's largest market, the U.S. The oil sands in Alberta are characterized by long reserve lives with steady, low levels, of volume growth expected. The reserves in Alberta rank third globally by volume.

Canada's National Energy Board (NEB) formally regulates the system. However, since 1995, the system has operated under a series of negotiated agreements (referred to as an incentive tolling settlement). The most recent iteration, the CTS, which went into effect July 1, 2011, increases the system's risk profile, marginally increasing the business risk of EI. Enbridge has taken on more risk through the CTS, while seeking higher returns and offering shippers greater transparency and stability in current and future tolls for the duration of the CTS, which expires June 30, 2021.

The key risk from the CTS is volume risk. Due to the long lead times and challenges associated with competing pipelines, the stable and transparent production growth profile, and the volume off ramp in the CTS that has a step-up threshold provision in 2014, the probability of an unexpected long-term, material volume decline is relatively low.

Other risks the company is now exposed to include operating costs, integrity spend as well as market risks. Material downside risk to Enbridge is mitigated through a combination of off-ramps in the CTS, or where possible market hedges. In addition to the volume off-ramp, other off-ramps cover regulatory changes that affect operating and integrity costs. Key hedges include foreign exchange, interest rates, and power (where possible). Tolls on the CTS increase at a rate of 75% of Canadian GDPP.

Given the competitive landscape, it appears likely that there would be strong visibility associated with a material decline in system volumes. The challenges facing TransCanada PipeLines Inc.'s Keystone XL highlight the political risks facing large, high-profile projects. Other long-term solutions to address oil sands capacity include the transmountain expansion project (which is conducting an open season that closes in January 2012) and Enbridge's Northern Gateway. Neither project would likely transport oil until the latter part of this decade. In the near term, pipeline capacity out of the western Canadian sedimentary basin could be expanded by increasing the capacity of either the Enbridge system or the existing Keystone pipeline, although neither appears to be currently contemplated.

Characterizing oil sands projects are high capital intensity, long production lives, and high total costs relative to traditional wells. In 2008, when oil prices fell dramatically, existing production continued largely unabated but low pricing led to project delays. Although our price deck does not forecast this type of a stress scenario, this does establish a historical precedent and supports our belief that production, and volumes on the Enbridge system are likely to be supported in a highly stressed economic and price environment.

Threshold volumes, which we believe provide some downside protection, are 1.25 mmbpd until Dec 31, 2014, and 1.35 mmbpd for the remainder of the contract. The time lag associated with thresholds minimizes some of the protection they provide, although we do not expect volumes to reach the thresholds. Thresholds are measured based on a rolling nine-month measurement period, followed by a 10-day notice period and a minimum 90 day negotiating period. At the end of this, if no agreement has been reached, the company could apply to the National Energy Board for relief through a return to cost of service. Threshold volumes also have carve-outs dealing with Bakken volumes and system availability.

A key feature of the CTS is that shippers may seek to renegotiate the settlement Jan. 1, 2013, if the Keystone XL pipeline has not received a U.S. presidential permit. The shippers have one month to provide notice if they wish to renegotiate on these grounds. Given that the CTS was negotiated under the assumption that Keystone XL would proceed, if volumes appear destined to be moved on the Enbridge system instead of Keystone XL for any meaningful amount of time, shippers would likely seek to renegotiate the CTS. Should renegotiation happen, we would not expect any outcome to negatively affect Enbridge any more than the impact of Keystone XL going ahead. As a result, we have conservatively assumed in our forecasts for the company that Keystone XL will proceed, or that shippers will renegotiate the CTS seeking an equivalent adjustment to the contract.

Enbridge Regional Oil Sands System. The system consists of two pipelines and related facilities that link the oilsands with terminals in Edmonton and Hardisty, Alta. The system benefits from long-term take-or-pay shipping contracts with strong counterparties. We expect returns to be relatively stable because the tolls under the contract are based on providing a specific return on equity--although returns could fall below expectations if operating costs exceed levels assumed in the agreement.

Southern Lights Pipeline. The Southern Lights pipeline features a 180,000 barrel-per-day, US$2.1 billion pipeline bringing diluent to Edmonton, Alta., from Chicago. It came into service July 1, 2010, on time and on budget. Its long-term take-or-pay contracts are consistent with Enbridge's approach to risk.

Other pipelines. Collectively, the earnings from these lines are quite small. The Spearhead pipeline is a very strategic asset that provides a platform that extends Enbridge's market reach into the critical oil hub at Cushing.

Gas Distribution (about 20% of earnings)

Enbridge Gas Distribution Inc. Enbridge Gas is regulated, and serves areas in central and eastern Ontario (including Toronto and Ottawa). The company's earnings are subject to an incentive regulatory structure that continues to provide a relatively predictable rate of return on equity. The lack of weather normalization will also affect earnings volatility; earnings can drop during years in which volumes are well below-average (particularly due to warmer-than-average winters).

Noverco Inc. Included in the Corporate segment, Enbridge owns a 38.9% interest in Noverco; it, in turn, owns a 71% interest in Gaz Metro L.P. (A-/Stable/--), which is the primary distributor of natural gas in Quebec and Vermont. Cost-of-service regulation with weather normalization support stable earnings. However, the company faces greater competitive pressures from cheaper forms of energy (particularly electricity) in Quebec.

Other gas distribution

Other gas distribution, which make up about 10% of this segment's earnings, include some smaller gas distribution companies for which earnings are reasonably stable.

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Gas Pipelines, Processing & Energy Services (about 10% of earnings)

Enbridge Offshore Pipelines Enbridge Offshore is a system of natural gas gathering and transmission lines in the Gulf of Mexico. Earnings from this system are volume-sensitive, and can fluctuate due to bad weather and the region's relatively mature production profile. Volumes have not recovered to pre-Macondo levels.

Alliance Pipeline U.S. The Alliance Pipeline U.S. connects gas production in western Canada with markets in the Midwestern and Northeastern U.S. The pipeline has firm shipping contracts that underpin the steady and predictable earnings. However, the shipping contracts expire in 2015. There is a risk that contracts will be renewed later with material reductions in rates, which would negatively affect profitability past 2015.

Vector Pipeline. The Vector pipeline runs between Chicago and a major storage facility in Dawn, Ont. The pipeline benefits from shipping contracts for about 90% of its capacity through 2015. However, as with Alliance, the contracts could expire that year or suffer from less favorable renewals.

Aux Sable Canada L.P. Enbridge has a 43% interest in Aux Sable, a natural gas liquids (NGL) extraction facility that the Alliance Pipeline near Chicago feeds. Aux Sable has a contract with BP Products North America Inc. for its NGL production. BP pays Aux Sable a fixed fee and a share of profits above a certain level, and reimburses Aux Sable for all operating, maintenance, and capital costs (subject to some limits on capital costs). The agreement, which greatly reduces downside risk to the company, extends to at least 2026 (although BP has the right to cancel the agreement if losses exceed a certain level). During periods of high fractionation margins (which generally occur when natural gas prices are low relative to crude oil prices), the earnings form this business can well exceed floor levels that the agreement provides for.

Energy services.

These businesses provide marketing services to Enbridge's clients. Earnings might be significantly more volatile than those of the rest of the company's businesses and are of limited credit support accordingly. Enbridge sold all of its international assets in 2008 and 2009 to fund growth its growth projects in Canada and the U.S.

Sponsored investments (about 20% of earnings)

Enbridge Energy Partners. EEP is a U.S.-based limited partnership that owns and operates crude oil pipelines and natural gas gathering and processing facilities. The company operates the Lakehead system, which connects with the Enbridge System at the Canada-U.S. border. Enbridge is the general partner and a 23.8% ownership interest and 35% economic interest in EEP.

Some of the company's earnings are subject to changes in volumes. However, as with the Enbridge System, the Lakehead system operates under the CTS but has priority in receiving tolls under the system. Natural gas volumes are somewhat more uncertain.

As with Enbridge, EEP has expanded its oil pipeline system to accommodate increasing supplies of crude from western Canada, leading to increased cash flows.

The company had two material oil spills in third-quarter 2010, which led to cleanup costs estimated at US$750 million (up from earlier estimates of US$430 million). Insurance coverage is limited to US$650 million. The total costs could increase if there are further cost increases, fines and penalties, and lawsuit costs, all of which are difficult to predict.

Enbridge Income Fund. EIF owns a 50% interest in the Canadian portion of the Alliance Pipeline, an oil gathering and transmission system in southeastern Saskatchewan, three wind projects, and a waste heat generating system. Enbridge has a 35% ownership interest and 69% economic interest in the fund. The issues concerning the lack of shipping contracts beyond 2015 on the Alliance Pipeline presents a risk to projected earnings. EIF increased its holdings in green energy projects in October 2011 when it purchased the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from Enbridge for C$1.2 billion. EIF has issued some of the trust units it expects to issue in connection with the acquisition, reducing Enbridge's stake to 69% from 72%.

Aggressive growth profile

The company consistently has a large capital program, although we believe a track record of executing large projects on time and on budget and consistently investing in assets characterized by long term, commercially secured contracts with relatively low-risk, stable cash flows both mitigate this. Enbridge is diversifying its base of investment somewhat, although the bulk of the capital program is for the core businesses. The capital program is shifting to a larger number of smaller projects from larger capital projects.

Capex for 2012 will likely exceed C$5 billion (on an asset base of more than C$31 billion). From 2012-2015, capex will likely exceed C$15 billion, and given the front-end loading of investment over the period, this might be conservative.

For the past several years Enbridge has been focused on organic growth, completing several large projects in 2010. In 2011 the company has announced some acquisitions, including a 71% interest in the Cabin Gas Plant and 50% of the Seaway Pipeline. The Cabin Gas Plant investment is consistent with typical investment parameters for Enbridge. The C$1.1 billion Seaway pipeline acquisition and planned reversal appears somewhat different, given that the asset does not have any existing contracts. However, the project effectively replaces the Wrangler project and the company has gauged shipper commitment from the open season from the Wrangler pipeline. We expect the asset to develop the same type of contractual profile as other Enbridge assets. In addition, this is a strategic acquisition for the company in that it becomes operational sooner than Wrangler, and provides Enbridge with a pipeline to the Gulf Coast refinery complex that it will try to lever into increased volumes on the mainline. The announcement has significantly reduced the WTI-Brent differential.

Profitability and diversity

Profitability has been increasing for several years, due to a large number of organic growth opportunities. The profit base is quite solid, in our opinion, since most earnings from its subsidiaries are either relatively low-risk, long-term contracts that provide floor levels of profitability or are directly regulated. The business has a relatively high degree of transparency regarding future earnings and we expect growth projects to continue to expand the stable base for earnings. Diversity is good, in our view, with a solid earnings base from regulated energy transportation and distribution assets.

Financial Policy

Enbridge's targeted financial parameters reflect a moderately aggressive financial risk profile but a reasonably conservative approach to financial risk management, in our view. The parameters include:

- Adjusted reported debt capitalization of 60%-65%, excluding the nonrecourse debt of EIF and Alliance Pipeline;
- Floating-rate debt as a proportion of total term debt of less than 25%;
- Maximum annual term debt maturities of less than 15% of total term debt;
- A common dividend payout of 60%-75%; and
- An earnings-at-risk target of less than 5%.

The policy to limit earnings at risk exposed to market prices to a maximum of 5% of the next 12 months forecasts earnings results in the company hedging about many market risks, including interest rates, foreign exchange and commodity price risks, among others. Counterparties are typically large shippers with investment-grade ratings on them. In part, a 10% earnings per share target also influences the capital program.

Significant Financial Risk Profile

Accounting

Enbridge reports in Canadian dollars and its financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP). The company plans to convert to U.S. GAAP for interim and annual financial statement reporting Jan. 1, 2012. We do not expect this to affect the ratings.

To better reflect Enbridge's assumed financial risk, Standard & Poor's makes an offsetting adjustment to its total debt outstanding for the amounts relating to purchased gas-in-storage at Enbridge Gas Distribution. The company's commercial paper program finances gas-in-storage amounts, and, as such, reports it as part of short-term debt. Given our expectation of full commodity cost recovery under the Ontario Energy Board's provisions and to eliminate the seasonality, we remove the amounts from short-term debt and total assets. Enbridge had total reported consolidated debt of C$15.2 billion in 2010; however, we used an adjusted debt total of C$15.0 billion. Standard & Poor's includes Enbridge's nonrecourse debt in total debt for analytical purposes.

Cash-flow adequacy

Given the high likelihood of ongoing capital investment, we expect last-12-month FFO of about C$2.5 billion to continue growing, albeit at a rate that increases in debt issuance offsets. As a result, we expect Enbridge's consolidated credit metrics to remain at the low end of the spectrum for the ratings, with some headroom over the 13% FFO-to-debt floor we have established. Adjusted leverage should remain within management's 60%-65% target, although on an adjusted basis we expect it will be closer to the high end of the range. We believe the company will remain free operating cash-flow negative for the next several years as a result of the large capital program.

We have noted management's willingness to support credit metrics through C$950 million in preferred share issuance and asset dropdowns to EIF. We also believe the company has other levers, including selling down some of its positions in its sponsored investments that it may use to raise cash to fund its growth program if required, supporting credit metrics.

Weakening Enbridge's cash flows somewhat is a reliance on subordinated distributions from affiliates in which the company does not have 100% ownership and ultimate control of cash flows. About 30% of 2010 adjusted earnings come from sponsored investments and several smaller assets across the company.

Table 1

Enbridge Inc.--Peer Comparison

Industry Sector: Gas

	--Fiscal year ended Dec. 31, 2010--							
	Enbridge Inc.	**TransCanada PipeLines Ltd.**	**Fortis Inc.**	**Veresen Inc.**	**Kinder Morgan Energy Partners L.P.**	**Colonial Pipeline Co.**	**Pembina Pipeline Corp.**	**Spectra Energy Corp.**
Rating as of Dec. 15, 2011	A-/Negative/--	A-/Stable/A-2	A-/Stable/--	BBB/Stable/--	BBB/Stable/A-2	A/Stable/A-1	BBB+/Stable/--	BBB+/Stable/--
Currency (mil.)	C$	C$	C$	C$	US$	US$	C$	US$
Revenues	15,127.0	8,064.0	3,664.0	690.5	8,077.7	987.2	1,255.1	4,945.0
EBITDA	2,410.0	4,297.1	1,177.2	375.2	2,936.1	597.8	319.2	2,811.6
Net income from continuing operations	970.0	1,256.0	330.0	79.7	1,316.3	292.7	186.7	1,043.0
Funds from operations (FFO)	2,075.8	2,959.9	720.6	246.6	2,423.2	395.5	249.4	1,790.5
Capital expenditures	2,341.0	4,616.8	954.9	51.0	1,017.1	38.3	229.8	1,345.3
Free operating cash flow	(528.2)	(1,912.9)	(236.3)	189.1	1,442.2	313.5	20.6	21.2
Discretionary cash flow	(958.7)	(3,133.4)	(474.8)	133.2	(384.4)	14.5	(233.5)	(701.8)
Cash and short-term investments	230.0	752.0	109.0	66.3	129.1	0.3	125.4	130.0
Debt	15,011.3	24,955.9	6,599.9	1,857.9	12,647.4	1,360.5	1,430.4	10,969.0
Equity	7,921.6	16,523.6	4,024.5	853.9	7,292.5	(238.7)	1,162.1	8,745.0
Adjusted ratios								
EBITDA margin (%)	15.9	53.3	32.1	54.3	36.3	60.6	25.4	56.9
EBITDA interest coverage (x)	3.2	2.7	3.0	3.2	5.5	7.1	4.2	4.2
EBIT interest coverage (x)	2.5	1.8	2.0	2.0	3.5	6.7	3.3	3.2
Return on capital (%)	7.8	6.6	7.1	7.9	9.6	39.1	9.8	10.0
FFO/debt (%)	13.8	11.9	10.9	13.3	19.2	29.1	17.4	16.3
Free operating cash flow/debt (%)	(3.5)	(7.7)	(3.6)	10.2	11.4	23.0	1.4	0.2
Debt/EBITDA (x)	6.2	5.8	5.6	5.0	4.3	2.3	4.5	3.9
Total debt/debt plus equity (%)	65.5	60.2	62.1	68.5	63.4	121.3	55.2	55.6

Table 2

Enbridge Inc.--Financial Summary

Industry Sector: Gas					
	--Fiscal year ended Dec. 31--				
(Mil. C$)	2010	2009	2008	2007	2006
Rating history	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--
Revenues	15,127.0	12,466.0	16,131.3	11,919.4	10,644.5
EBITDA	2,410.0	2,047.0	2,034.4	1,751.1	1,722.2
Net income from continuing operations	970.0	1,562.0	1,327.7	707.1	622.3
Funds from operations (FFO)	2,075.8	1,671.0	1,316.2	1,305.7	1,137.4
Capital expenditures	2,341.0	3,224.0	3,554.7	2,238.0	1,164.7
Dividends paid	430.5	450.5	362.7	455.8	406.6
Debt	15,011.3	13,921.2	12,674.6	9,956.0	9,387.6
Preferred stock	62.5	62.5	62.5	62.5	62.5
Equity	7,921.6	7,793.5	7,218.1	5,827.0	5,154.7
Debt and equity	22,932.9	21,714.6	19,892.7	15,783.0	14,542.3
Adjusted ratios					
EBITDA margin (%)	15.9	16.4	12.6	14.7	16.2
EBIT interest coverage (x)	2.5	3.0	2.7	2.4	2.4
FFO interest coverage (x)	3.7	3.3	3.0	3.1	2.9
FFO/debt (%)	13.8	12.0	10.4	13.1	12.1
Discretionary cash flow/debt (%)	(6.4)	(12.6)	(20.6)	(13.7)	(3.3)
Net cash flow/capex (%)	70.3	37.9	26.8	38.0	62.8
Debt/debt and equity (%)	65.5	64.1	63.7	63.1	64.6
Return on capital (%)	7.8	9.4	9.1	9.2	9.5
Return on common equity (%)	11.2	19.4	20.3	12.9	13.8
Common dividend payout ratio (unadjusted; %)	67.3	35.7	37.0	64.6	65.5

Table 3

Reconciliation Of Enbridge Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2010--									
Enbridge Inc. reported amounts	Debt	Shareholders' equity	Revenues	EBITDA	Operating income	Interest expense	Cash flow from operations	Cash flow from operations	Dividends paid	Capital expenditures
Reported	15,172.0	7,565.0	15,127.0	2,370.0	1,506.0	687.0	1,851.0	1,851.0	434.0	2,407.0
Standard & Poor's adjustments										
Intermediate hybrids reported as equity	62.5	(62.5)	N/A	N/A	N/A	3.5	(3.5)	(3.5)	(3.5)	N/A
Postretirement benefit obligations	108.8	(238.9)	N/A	2.0	2.0	1.0	31.3	31.3	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	66.0	(66.0)	(66.0)	N/A	(66.0)

Table 3

Reconciliation Of Enbridge Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$) (cont.)										
Share-based compensation expense	N/A	N/A	N/A	38.0	N/A	N/A	N/A	N/A	N/A	N/A
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	N/A	407.0	N/A	N/A	N/A	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	263.0	N/A	N/A
Minority interests	N/A	658.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Debt--other	(332.0)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	(160.7)	356.6	0.0	40.0	409.0	70.5	(38.2)	224.8	(3.5)	(66.0)
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	15,011.3	7,921.6	15,127.0	2,410.0	1,915.0	757.5	1,812.8	2,075.8	430.5	2,341.0

N/A--Not applicable.

Related Criteria And Research

- Rating Criteria For U.S. Midstream Energy Companies, Dec. 18, 2008
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008

Ratings Detail (As Of December 15, 2011)	
Enbridge Inc.	
Corporate Credit Rating	A-/Stable/--
Commercial Paper	
Canadian National Scale Commercial Paper Rating	A-1(LOW)
Preferred Stock (3 Issues)	BBB
Canadian Preferred Stock Rating (3 Issues)	P-2
Senior Unsecured (18 Issues)	A-
Corporate Credit Ratings History	
06-Dec-2011	A-/Stable/--
23-Mar-2011	A-/Negative/--
25-Nov-2003	A-/Stable/--
Business Risk Profile	Excellent
Financial Risk Profile	Significant

Ratings Detail (As Of December 15, 2011) (cont.)	
Related Entities	
Enbridge Gas Distribution Inc.	
Issuer Credit Rating	A-/Stable/--
Commercial Paper	
Canadian National Scale Commercial Paper Rating	A-1(LOW)
Preference Stock (1 Issue)	BBB
Canadian Preferred Stock Rating (1 Issue)	P-2
Senior Unsecured (16 Issues)	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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February 29, 2012

Fortis Inc.

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Table Of Contents

Fortis Inc.

Major Rating Factors

Corporate Credit Rating
A-/Watch Neg/--

Strengths:

- Diversified portfolio of low-risk monopoly electricity and gas distribution businesses
- Stable, regulated cash flows, with supportive regulatory regimes and limited commodity price and volume exposure

Weaknesses:

- Weak consolidated credit metrics for the ratings and deconsolidated metrics that acquisitions could pressure
- Higher business risk in unregulated businesses that account for about 10-15% of consolidated EBITDA

Rationale

The ratings on St. John's, Nfld.-based Fortis Inc. reflect Standard & Poor's Ratings Services' opinion of the company's excellent business risk profile and significant financial risk profile. Our business risk assessment reflects the company's diversified portfolio of independent regulated utility subsidiaries; the stable and predictable regulated cash flows that flow from these investments; and what we view as a focused and well-executed growth strategy. Characterizing Fortis' financial risk profile, in our view, are the deemed regulatory capital structure at each of its subsidiaries, and a proportionally low amount of actual and expected debt held at the parent level. We believe that exposure, albeit limited, to a low proportion of total assets, to higher-risk commercial and hospitality real estate, and merchant electricity generation somewhat offset the strengths of both its business risk and financial risk profiles.

We placed our ratings on Fortis on CreditWatch with negative implications Feb. 21, 2012, reflecting our view that following the close of the proposed acquisition of CH Energy Group Inc. (not rated) for about C$1.5 billion, there is at least a one-in-two probability that the company's deconsolidated credit metrics might deteriorate below thresholds we have previously established for the ratings.

Fortis is a holding company with 100% interests in a number of regulated utilities in Canada. They include FortisBC Holdings Inc. (gas distributor in British Columbia [B.C.]; not rated); FortisBC (electricity distributor for portions of B.C.; not rated); Newfoundland Power Inc. (electricity provider for the island portion of the province); FortisAlberta Inc. (electricity distributor in parts of Alberta; A-/Stable/--); Maritime Electric Co. Ltd. (electricity provider in Prince Edward Island; BBB+/Stable/--); and FortisOntario (electricity provider in parts of Ontario; not rated). The company also has holdings in regulated utilities in the Cayman Islands and Turks and Caicos; it has nonregulated hydro power generation and real estate and hotel investments that account for 10%-15% of consolidated EBITDA. We believe the quality, predictability, and diversity of the regulatory support Fortis enjoys underpin our assessment of the company's business risk profile. Diverse markets, climates, and customers further reduce its dependence on any individual market and add creditworthiness, although FortisBC Holdings, the largest holding, typically accounts for 35%-40% of consolidated earnings. Fortis had C$5.9 billion of reported, consolidated debt as of Dec. 31, 2011.

As a holding company, the principal sources of Fortis' cash flows are dividends from its utility holdings, interests from loans to some of its subsidiaries, and free cash flow from its nonregulated operations. Owing to the utilities' monopoly positions and predictable regulation, the collective distributions are stable and reliable; acquisitions and organic growth at its B.C.- and Alberta-based operating companies have spurred growth in distributions. Fortis continues to own and operate nonregulated hydroelectric generating facilities in the country. We believe that the regulated businesses in the Caribbean could face more operating issues as a result of slow economic conditions and less predictable regulation.

Fortis' practice of maintaining financial separation with its subsidiaries supports our ratings. Although the company's management guides the subsidiaries to some extent, they operate independently, and Fortis does not guarantee their debt. However, the company could assist its subsidiaries in their expansions and should they encounter short-term financial or operational difficulties.

Fortis' consolidated leverage is high, in our opinion, at about 60% total debt-to-total capital as of Dec. 31, 2011, but consistent with stable Canadian provincial regulatory frameworks that dominate the portfolio. The company typically finances regulated subsidiaries at about a 55%-65% leverage level, in line with the deemed capital structure that their respective regulators use to set tariffs for capital cost recovery. We also consider Fortis' deconsolidated leverage, which is lower, in our analysis. The company has historically financed its acquisitions with common and preferred share issuances. We regard the preferred shares as having intermediate equity characteristics in accordance with our criteria on hybrid securities, and treat them as 50% debt and 50% equity. Although Standard & Poor's expects that the company will continue to grow, we expect it to remain focused primarily on expanding through acquisitions of regulated assets with predictable returns and increasing the rate bases in its existing portfolio of regulated utilities.

Supporting our view that Fortis' financial risk profile is significant, and somewhat stronger than its key credit metrics would suggest based on our criteria, are the following factors:

- The portfolio effect and separation of each of its subsidiaries;
- Each subsidiary's direct debt financing;
- Stable and diverse cash flows;
- Sellable and long-lived assets;
- Some discretionary capital;
- A consistent financial policy; and
- Good access to debt and equity capital markets.

Nevertheless, we believe Fortis' consolidated interest and debt coverage's are aggressive-to-highly leveraged. Consolidated adjusted funds from operations (AFFO) interest coverage has historically been about 2.5x-3.0x, while AFFO-to-total debt has historically ranged from 10%-12%. We expect these measures to remain near there in the medium term.

Liquidity

Fortis' liquidity is adequate, in our view. At the holding company level, we expect that liquidity sources will be sufficient to cover uses by more than 1.2x. Our assessment of the company's liquidity profile incorporates the following expectations and assumptions:

- We expect that in the event of a 15% decline in deconsolidated earnings, the company's sources of funds would still exceed its uses.

- Liquidity sources include expected dividends and interests from Fortis' subsidiaries of more than C$250 million per year and unused credit facilities of about C$800 million as of Dec. 31, 2011.
- Uses of capital include primarily capital spending and dividends to shareholders of about C$600 million, but we believe that some of the capital spending has some deferability.

In our view, the company has sound relationships with its banks and generally satisfactory standing in credit markets.

Accounting

On Jan. 1, 2012, Fortis converted to U.S. generally accepted accounting principles (GAAP) for interim and annual financial reporting. We do not expect this to affect the ratings. The company previously prepared its financial statements in accordance with Canadian GAAP.

CreditWatch

We will resolve the CreditWatch placement once greater details related to the CH Energy transaction, including a financing plan, become available and the transaction closes. We could lower the ratings if debt levels increase as a result of the transaction and Fortis is unable to meet established thresholds we associate with the ratings, including company-level debt coverage from cash flows from its subsidiaries of more than 20% and consolidated adjusted funds from operations-to-debt of more than 10%. However, while less likely, we could affirm the ratings on Fortis and return to a stable outlook if a very meaningful component of the financing plan consists of equity and we conclude that forecast credit metrics are at levels consistent with the current ratings.

Table 1

Fortis Inc.--Peer Comparison

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31, 2010--				
(Mil. C$)	**Fortis Inc.**	**Enbridge Inc.**	**TransCanada PipeLines Ltd.**	**CU Inc.**	**EPCOR Utilities Inc.**
Rating as of Feb. 29, 2012	A-/Watch Neg/--	A-/Stable/--	A-/Stable/A-2	A/Stable/A-1	BBB+/Stable/--
Revenues	3,664.0	15,127.0	8,064.0	1,476.7	1,473.0
EBITDA	1,177.2	2,410.0	4,297.1	672.9	309.9
Net income from continuing operations	330.0	970.0	1,256.0	266.5	133.0
Funds from operations (FFO)	716.6	2,075.8	2,959.9	471.7	151.7
Capital expenditures	954.9	2,341.0	4,616.8	696.3	217.1
Free operating cash flow	(240.3)	(528.2)	(1,912.9)	(249.6)	(56.4)
Dividends paid	224.5	430.5	1,220.5	9.9	136.0
Discretionary cash flow	(464.8)	(958.7)	(3,133.4)	(259.4)	(192.4)
Cash and short-term investments	109.0	230.0	752.0	10.3	104.0
Debt	6,895.9	15,011.3	24,955.9	3,160.9	1,804.8
Preferred stock	456.0	62.5	687.0	224.7	0.0
Equity	3,728.5	7,921.6	16,523.6	2,428.5	2,461.4
Debt and equity	10,624.4	22,932.9	41,479.5	5,589.4	4,266.2

Table 1

Fortis Inc.--Peer Comparison (cont.)

Adjusted ratios					
FFO interest coverage (x)	2.6	3.7	2.9	3.1	2.1
FFO/debt (%)	10.4	13.8	11.9	14.9	8.4
Free operating cash flow/debt (%)	(3.5)	(3.5)	(7.7)	(7.9)	(3.1)
Discretionary cash flow/debt (%)	(6.7)	(6.4)	(12.6)	(8.2)	(10.7)
Net cash flow/capex (%)	51.5	70.3	37.7	66.3	7.2
Debt/EBITDA (x)	5.9	6.2	5.8	4.7	5.8
Total debt/debt plus equity (%)	64.9	65.5	60.2	56.6	42.3
Return on capital (%)	7.1	7.8	6.6	8.8	7.1
Return on common equity (%)	7.9	11.2	4.3	10.9	5.2
Common dividend payout ratio (unadjusted; %)	85.6	67.3	89.7	0.0	102.3

Table 2

Fortis Inc.--Financial Summary

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2010**	**2009**	**2008**	**2007**	**2006**
Rating history	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--	BBB+/Stable/--
Revenues	3,664.0	3,637.0	3,903.0	2,718.0	1,462.0
EBITDA	1,177.2	1,085.0	1,064.7	827.3	534.7
Net income from continuing operations	330.0	297.0	276.0	216.0	165.4
Funds from operations (FFO)	716.6	656.7	648.4	492.2	346.1
Capital expenditures	954.9	927.0	822.1	837.5	445.0
Dividends paid	224.5	160.5	185.5	151.5	82.5
Debt	6,895.9	6,591.5	6,159.9	6,166.7	3,209.4
Preferred stock	456.0	333.5	333.5	160.3	159.7
Equity	3,728.5	3,497.4	3,385.5	2,871.1	1,567.6
Debt and equity	10,624.4	10,088.9	9,545.4	9,037.7	4,777.0
Adjusted ratios					
EBITDA margin (%)	32.1	29.8	27.3	30.4	36.6
EBIT interest coverage (x)	1.9	1.9	1.8	1.8	2.2
FFO interest coverage (x)	2.6	2.6	2.5	2.5	2.9
FFO/debt (%)	10.4	10.0	10.5	8.0	10.8
Discretionary cash flow/debt (%)	(6.7)	(7.2)	(5.2)	(10.0)	(6.8)
Net cash flow/capex (%)	51.5	53.5	56.3	40.7	59.2
Debt/debt and equity (%)	64.9	65.3	64.5	68.2	67.2
Return on capital (%)	7.1	7.2	7.7	8.2	8.6
Return on common equity (%)	7.9	7.8	7.6	9.0	11.1
Common dividend payout ratio (unadjusted; %)	85.6	50.8	70.1	66.3	48.8

Table 3

Reconciliation Of Fortis Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2010--									
Fortis Inc. reported amounts	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	6,023.0	4,217.0	3,664.0	1,150.0	740.0	348.0	740.0	740.0	247.0	960.0
Standard & Poor's adjustments										
Operating leases	101.8	N/A	N/A	6.2	6.2	6.2	10.8	10.8	N/A	7.9
Intermediate hybrids reported as equity	456.0	(456.0)	N/A	N/A	N/A	22.5	(22.5)	(22.5)	(22.5)	N/A
Postretirement benefit obligations	232.6	(194.5)	N/A	17.0	17.0	11.0	(0.7)	(0.7)	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	13.0	(13.0)	(13.0)	N/A	(13.0)
Share-based compensation expense	N/A	N/A	N/A	4.0	N/A	N/A	N/A	N/A	N/A	N/A
Asset retirement obligations	230.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	N/A	15.0	N/A	N/A	N/A	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.0	N/A	N/A
Minority interests	N/A	162.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Debt--other	(148.0)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	872.9	(488.5)	0.0	27.2	38.2	52.7	(25.4)	(23.4)	(22.5)	(5.1)
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	6,895.9	3,728.5	3,664.0	1,177.2	778.2	400.7	714.6	716.6	224.5	954.9

N/A--Not applicable.

Related Criteria And Research:

- Research Update: Fortis Inc. Ratings Put On CreditWatch Negative On Announced C$1.5 Billion Acquisition, Feb. 22, 2012
- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008

- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- Corporate Criteria: Ratios And Adjustments, April 15, 2008

Ratings Detail (As Of February 29, 2012)	
Fortis Inc.	
Corporate Credit Rating	A-/Watch Neg/--
Preference Stock	
Canadian Preferred Stock Rating (1 Issue)	P-2/Watch Neg
Preferred Stock (4 Issues)	BBB/Watch Neg
Canadian Preferred Stock Rating (4 Issues)	P-2/Watch Neg
Senior Unsecured (1 Issue)	A-/Watch Neg
Corporate Credit Ratings History	
22-Feb-2012	A-/Watch Neg/--
19-Jun-2007	A-/Stable/--
26-Feb-2007	BBB+/Watch Pos/--
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
Caribbean Utilities Co. Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured (7 Issues)	A-
FortisAlberta Inc.	
Issuer Credit Rating	A-/Watch Neg/--
Senior Unsecured (10 Issues)	A-/Watch Neg
Maritime Electric Co. Ltd.	
Issuer Credit Rating	BBB+/Stable/--
Senior Secured (6 Issues)	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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February 27, 2012

TransCanada PipeLines Ltd.
TransCanada Corp.

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Table Of Contents

TransCanada PipeLines Ltd.
TransCanada Corp.

Major Rating Factors

Corporate Credit Rating
A-/Stable/--

Strengths:

- Cash flow stability from highly diversified asset base in regulated oil and gas pipelines, and power generation
- Solid portfolio of growth projects that will contribute materially to cash flow in coming years

Weaknesses:

- Financial metrics that are tight relative to our thresholds
- Uncertainty surrounding the timing of the Keystone XL project, a major growth initiative for the company
- Revamp of the tolling mechanism on the mainline, which will introduce regulatory risk

Rationale

The ratings on Calgary, Alta.-based TransCanada PipeLines Ltd. and TransCanada Corp. reflect Standard & Poor's Ratings Services' view of the companies' highly diversified asset base in oil and gas pipelines and power generation that provides cash flow stability. TransCanada has a large portfolio of growth projects that will contribute materially to cash flow in coming years. In our opinion, offsetting these strengths is significant uncertainty surrounding the timing of the Keystone XL pipeline, and regulatory risk surrounding the revamp of the mainline tolling mechanism. In addition, we forecast financial metrics that are tight relative to our thresholds for the ratings, limiting the companies' capacity to absorb cost overruns.

Our assessment of the business risk takes into account the asset base's significant diversity, and the regulated nature of all of its oil and natural gas pipeline, eastern, and U.S. power assets. Growth in the energy and oil pipelines segments has reduced the contribution from the Canadian mainline to 40% from 49% in 2009. We expect further reduction as the planned restart of Bruce Power will occur in 2012, and that Keystone XL will gain approval in 2013 for an in-service date of early 2015.

Keystone XL continues to be delayed after the U.S. State Department denied the presidential permit in January 2012. The company will reapply for a permit, but we do not expect to see an approval until after the November 2012 U.S. elections. Given the ongoing delays, TransCanada is now expecting an in-service date early in 2015--a slight slippage from the previous late 2014 estimate. We continue to see risk that the timing could change again; however, the delay in capital spending is a positive to the credit metrics.

In September, TransCanada applied to the National Energy Board (NEB) for a comprehensive restructuring of the tolling system on the mainline, Alberta, and Foothills system. Volumes have declined steadily in the past several years, stemming from increasing intra-Alberta gas consumption and competition from new basins and other pipelines delivering into the eastern markets. This has resulted in per-unit tolls spiking dramatically. The proposal seeks to address the volume declines by reducing tolls. In the near term, we believe that revenues will be lower under the revised structure, although the competitive position of the pipeline will improve.

Despite the delays with expansion projects and issues surrounding the mainline, we believe TransCanada's business risk has improved with the addition of regulated and long-term contracted cash flows.

Our view of the company's financial risk profile is unchanged. We forecast funds from operations (FFO)-to-debt (Standard & Poor's-adjusted) to be near the thresholds for the ratings, at 14.8% in 2012 and 14.9% in 2013. However, this will improve as capital spending on Keystone and other projects winds down, and revenue contribution begins. Looking further out, we see FFO-to-debt improving more than 5% once Keystone XL contributes to full-year cash flows. Mitigating the potential improvement is the company's propensity to continue to grow through acquisition and development of large-scale energy infrastructure projects.

Liquidity

In our view, liquidity is adequate. TransCanada has sources less uses of cash of C$2.3 billion in 2012, and sources over uses of 1.4x. The company has substantial undrawn credit facilities of more than C$4.5 billion, which it can use to finance the Keystone XL and other capital programs. We believe that TransCanada continues to have excellent access to capital, and will be able to refinance maturing debt of C$935 million in 2012 in a timely manner.

Accounting

TransCanada used Canadian generally accepted accounting principles (GAAP) in fiscal 2011, which is consistent with TransCanada Pipeline's accounting policies. As of January 2012, TCC adopted U.S. GAAP. We do not expect the accounting framework used for future reporting to affect our ratings.

In accordance with Standard & Poor's published criteria, we make adjustments to debt that take into account off-balance-sheet debt-like instruments such as the present value of operating leases, power purchase agreements, and preferred shares.

Outlook

The stable outlook reflects our expectation that TransCanada's diverse businesses will continue to generate stable cash flows to support its financial risk profile during the significant capital expansion. We expect adjusted FFO-to-debt (Standard & Poor's-adjusted) to improve from the forecast 14.8% level in 2012 and 14.9% in 2013 as projects finish and cash flows ramp up. We believe there is little room for further capital spending beyond our assumptions, unless the financing is more consistent with the overall capital structure. A negative rating or outlook action is possible if the metrics do not improve once projects such as Keystone XL are complete. A positive outlook is not likely during our two-year outlook period, but could happen if there is a structural shift upwards in financial metrics.

Table 1

TransCanada PipeLines Ltd.--Peer Comparison

Industry Sector: Utility Company

	--Fiscal year ended Dec. 31, 2011--		--Fiscal year ended Dec. 31, 2010--		
	TransCanada PipeLines Ltd.	Enbridge Inc.	Veresen Inc.	Colonial Pipeline Co.	Kinder Morgan Energy Partners L.P.
Rating as of Feb. 21, 2012	A-/Stable/A-2	A-/Stable/--	BBB/Stable/--	A/Stable/A-1	BBB/Stable/A-2

Table 1

TransCanada PipeLines Ltd.--Peer Comparison (cont.)

Currency (mil.)	--C$--			--US$--	
Revenues	8,723.0	19,402.0	690.5	987.2	8,077.7
EBITDA	4,517.0	2,846.0	375.2	597.8	2,936.1
Net income from continuing operations	1,387.0	1,004.0	79.7	292.7	1,316.3
Funds from operations (FFO)	3,075.7	2,452.0	246.6	395.5	2,423.2
Capital expenditures	4,391.2	2,681.0	51.0	38.3	1,017.1
Free operating cash flow	(1,336.2)	22.0	189.1	313.5	1,442.2
Discretionary cash flow	(2,541.5)	(515.0)	133.2	14.5	(384.4)
Cash and short-term investments	823.7	420.0	66.3	0.3	129.1
Debt	24,022.1	16,232.0	1,857.9	1,360.5	12,647.4
Equity	17,106.8	9,687.0	853.9	(238.7)	7,292.5
Adjusted ratios					
EBITDA margin (%)	51.8	14.7	54.3	60.6	36.3
EBITDA interest coverage (x)	2.9	4.0	3.2	7.1	5.5
EBIT interest coverage (x)	2.0	3.3	2.0	6.7	3.5
Return on capital (%)	7.2	8.7	7.9	39.1	9.6
FFO/debt (%)	12.8	15.1	13.3	29.1	19.2
Free operating cash flow/debt (%)	(5.6)	0.1	10.2	23.0	11.4
Debt/EBITDA (x)	5.3	5.7	5.0	2.3	4.3
Total debt/debt plus equity (%)	58.4	62.6	68.5	121.3	63.4

Table 2

TransCanada Corp.--Financial Summary

Industry Sector: Utility Company

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2011**	**2010**	**2009**	**2008**	**2007**
Rating history	A-/Stable/--	A-/Stable/--	A-/Stable/--	NR	NR
Revenues	9,139.0	8,064.0	8,966.0	8,619.0	8,828.0
EBITDA	5,122.7	4,290.1	4,448.0	4,403.8	4,202.9
Net income from continuing operations	1,604.0	1,294.0	1,380.0	1,440.0	1,223.0
Funds from operations (FFO)	3,621.5	3,012.2	2,967.6	3,039.4	2,641.7
Capital expenditures	3,174.9	4,619.8	5,530.4	3,129.2	1,780.7
Dividends paid	1,163.3	887.0	850.5	741.0	644.5
Debt	25,962.4	25,585.4	23,880.4	23,229.9	18,527.7
Preferred stock	922.0	1,299.0	982.0	801.0	682.0
Equity	18,037.9	17,280.6	16,714.4	14,224.1	10,820.3
Debt and equity	44,000.3	42,866.0	40,594.8	37,454.0	29,348.0
Adjusted ratios					
EBITDA margin (%)	56.1	53.2	49.6	51.1	47.6
EBIT interest coverage (x)	2.3	1.9	2.0	2.4	2.3

Table 2

TransCanada Corp.--Financial Summary (cont.)					
FFO interest coverage (x)	3.2	2.5	2.9	3.1	3.0
FFO/debt (%)	13.9	11.8	12.4	13.1	14.3
Discretionary cash flow/debt (%)	(1.6)	(10.7)	(14.7)	(4.4)	2.3
Net cash flow/capex (%)	77.4	46.0	38.3	73.4	112.2
Debt/debt and equity (%)	59.0	59.7	58.8	62.0	63.1
Return on capital (%)	7.4	6.4	7.5	9.2	10.8
Return on common equity (%)	7.8	4.2	7.0	11.3	13.0
Common dividend payout ratio (unadjusted; %)	76.2	90.4	75.1	58.7	60.9

NR--Not rated.

Table 3

Reconciliation Of TransCanada Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2011--									
TransCanada Corp. reported amounts	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	22,278.0	17,713.0	9,139.0	4,749.0	3,221.0	992.0	3,995.0	3,995.0	1,169.0	3,274.0
Standard & Poor's adjustments										
Operating leases	533.2	N/A	N/A	34.7	34.7	34.7	41.8	41.8	N/A	19.6
Intermediate hybrids reported as debt	(504.5)	504.5	N/A	N/A	N/A	(32.8)	32.8	32.8	32.8	N/A
Intermediate hybrids reported as equity	806.5	(806.5)	N/A	N/A	N/A	38.5	(38.5)	(38.5)	(38.5)	N/A
Postretirement benefit obligations	235.9	(449.1)	N/A	12.0	12.0	N/A	22.1	22.1	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	302.0	(302.0)	(302.0)	N/A	(302.0)
Power purchase agreements	2,189.5	N/A	N/A	323.0	139.7	139.7	183.3	183.3	N/A	183.3
Asset retirement obligations	50.7	N/A	N/A	4.0	4.0	4.0	(2.9)	(2.9)	N/A	N/A
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	N/A	55.0	N/A	N/A	N/A	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(310.0)	N/A	N/A
Minority interests	N/A	1,076.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 3

Reconciliation Of TransCanada Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$) (cont.)										
Debt--accrued interest not included in reported debt	373.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	3,684.4	324.9	0.0	373.7	245.5	486.2	(63.5)	(373.5)	(5.7)	(99.1)
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	25,962.4	18,037.9	9,139.0	5,122.7	3,466.5	1,478.2	3,931.5	3,621.5	1,163.3	3,174.9

N/A--Not applicable.

Ratings Detail (As Of February 27, 2012)*	
TransCanada Corp.	
Corporate Credit Rating	A-/Stable/--
Preferred Stock (3 Issues)	BBB
Canadian Preferred Stock Rating (3 Issues)	P-2
Corporate Credit Ratings History	
30-Sep-2009	A-/Stable/--
Business Risk Profile	Excellent
Financial Risk Profile	Significant
Related Entities	
ANR Pipeline Co.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured (3 Issues)	A-
NOVA Gas Transmission Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured (12 Issues)	A-
TransCanada PipeLines Ltd.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Foreign Currency	A-2
Junior Subordinated (1 Issue)	BBB
Preferred Stock (1 Issue)	BBB
Canadian Preferred Stock Rating (1 Issue)	P-2
Senior Unsecured (43 Issues)	A-
TransCanada PipeLine USA Ltd.	
Issuer Credit Rating	A-/Stable/A-2

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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February 24, 2012

Puget Sound Energy Inc.

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Table Of Contents

Puget Sound Energy Inc.

Major Rating Factors

Corporate Credit Rating

BBB/Stable/A-2

Strengths:

- Regulated integrated electric and natural gas utility operations that provide an essential service and relatively stable cash flows;
- Generally supportive regulatory framework with a power cost adjustment (PCA) mechanism and purchased gas adjustment mechanisms, although the PCA mechanism does not provide full recovery;
- The absence of material unregulated businesses; and
- A power-cost-only rate case procedure that functions as a limited-scope rate case for resource additions and other power costs, thus reducing rate lag.

Weaknesses:

- Aggressive financial strategy, reflecting double leverage added at the holding company;
- Significant capital expenditure requirements -- driven by infrastructure replacement, resource requirements, and regulations -- that increase rate lag; and
- Moderate price and commodity risk related to a significant reliance on hydroelectric and gas-fired resources, as well as market purchases.

Rationale

The 'BBB' corporate credit rating (CCR) on Puget Sound Energy Inc. (PSE) reflects the excellent business risk profile and aggressive financial risk profile of integrated electric and gas utility operations, consolidated financial measures that are weaker than PSE's because of additional debt leverage at 'BB+' rated holding company Puget Energy Inc. (Puget), and the insulating regulatory provisions pledged at the utility operating company that further disadvantage holding company financial obligations relative to the operating company. However, the financial dependency of the holding company on subsidiary cash flows and the absence of other operating units limit the degree of differentiation between the two credit ratings.

The business risk profile of Puget is excellent, primarily reflecting PSE's combined electric and gas utility business focused in the Puget Sound region of Washington State. PSE is subject to regulation by the Washington Utilities and Transportation Commission. The company's management of its regulatory relationships in Washington is a key driver of credit quality, especially in light of PSE's relatively high capital needs and commodity cost exposure, and we assess the regulatory environment as less credit supportive. PSE's cost recovery mechanisms for purchased gas and power costs support credit quality.

Puget's consolidated financial risk profile is aggressive under Standard & Poor's corporate risk matrix. Our internal projections reflect consolidated adjusted funds from operations (FFO) to debt of 13%, debt to EBITDA of 5.3x, and debt to capital of 62% based on our anticipation of continued dividends and reduced capital spending levels along with rate case revenues that will continue to support current ratings. We anticipate that credit metrics will trend within a narrow band over the next two years, except for periodic weather variance and shifts in power and gas prices, which we believe the company has the ability to absorb. FFO to total debt was 13.1%, excluding reclassified derivative contracts, for the 12 months ended Sept. 30, 2011. Debt to EBITDA was 5x and debt to capital was 61.3% as of Sept 30 2011. Our credit metrics include adjustments for operating leases, hybrid equity debt securities, postretirement benefit obligations, purchased power agreements, and accrued interest.

Liquidity

The short-term rating on PSE is 'A-2' and consolidated liquidity is strong under our corporate liquidity methodology, which categorizes liquidity under five standard descriptors. Projected sources of liquidity (mainly operating cash flow and available bank lines) exceed projected uses (mainly necessary capital expenditures, debt maturities, and common dividends) for the upcoming 12 months by 1.5x or more. Even over the next 24 months, the measure remains more than 1x and sources will exceed uses even if forecast EBITDA declines by 30%.

The company has been proactive in reducing its significant refinancing risks. Aside from the operating company credit facilities, most transaction-related financings were completed sooner than we had anticipated. PSE has three committed unsecured revolving credit facilities that provide, in aggregate, $1.15 billion in short-term borrowing capability: a $400 million credit agreement for working capital needs, a $400 million credit facility for funding capital expenditures, and a $350 million facility to support other working capital and energy hedging activities. As of Sept. 30, 2011, PSE had a $12.5 million letter of credit working capital facility and $119 million outstanding under the commercial paper program, and nothing drawn or outstanding under the capital expenditure facility or the hedging facility. These facilities mature February of 2014.

On Feb. 10, 2012, Puget Energy entered into a new $1 billion credit facility with a term of five years that replaced the prior facility and term loan balance. Initial borrowing under the Puget facility totaled $864 million. Most of this debt is a result of the go-private merger transaction. Puget's credit agreement contains financial covenants that can limit its availability, including a minimum group FFO coverage ratio of 2x and a maximum leverage ratio of 65%. The facility matures Feb. 10, 2017.

Recovery analysis

Puget's term loans and senior secured notes (secured by stock) are not notched from our 'BB+' issuer credit rating (ICR) on the company, based on our speculative-grade recovery criteria and our anticipation of meaningful (50% to 70%) recovery. (For the complete recovery analysis, please refer to our recovery report published Feb. 16, 2012, on RatingsDirect on the Global Credit Portal.)

We rate PSE's first mortgage bonds (FMB) 'A-', two notches higher than the CCR, with a recovery rating of '1+.' We assign recovery ratings to FMBs issued by U.S. utilities, and this can result in issue ratings being notched above the CCR on a utility, depending on the CCR category and the extent of the collateral coverage. The investment-grade FMB recovery methodology is based on the ample historical record of nearly 100% recovery for secured-bond holders in utility bankruptcies and our view that the factors that supported those recoveries (the small size of the creditor class and the durable value of utility rate-based assets during and after a reorganization, given the essential service provided and the high replacement cost) will persist. Under our notching criteria, we consider the limitations of FMB issuance under the utility's indenture relative to the value of the collateral pledged to bondholders, management's stated intentions on future FMB issuance, and the regulatory limitations on bond issuance when assigning issue ratings to utility FMBs. FMB ratings can exceed a utility CCR by as much as one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories. (See "Criteria: Changes To Collateral Coverage Requirements For '1+' Recovery Ratings On U.S. Utility First Mortgage Bonds," published Sept. 6, 2007, on RatingsDirect on the Global Credit Portal.) PSE's collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating of 'A-', two notches above the CCR.

Outlook

The stable outlook reflects our anticipation of reasonable and timely rate relief related to resource additions and changes in power costs at PSE, combined with our forecast on a consolidated adjusted basis of FFO to debt of more than 13%, debt to EBITDA of 5.3x, and debt to capital of 62%. We could lower the rating if Puget fails to prudently manage its financial risk profile and FFO to debt drops to less than 12%, debt to EBITDA rises to more than 5.5x, or debt to capital rises to more than 65%, on a sustained basis. We could raise the rating if Puget is able to achieve higher credit metrics, specifically FFO to debt of more than 15% on a sustainable basis, debt to EBITDA of less than 4.5x, and debt to capital of less than 55%. However, positive ratings momentum is unlikely at this time and stronger credit metrics at utility PSE will not benefit its rating absent improvement on a consolidated basis.

Table 1.

Puget Energy Inc. -- Peer Comparison

	Puget Energy Inc.	Avista Corp.	Portland General Electric Co.	NorthWestern Corp.	IDACORP Inc.
Rating as of Jan. 30, 2012	BB+/Stable/--	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	3,269.6	1,577.1	1,777.3	1,163.6	1,015.4
EBITDA	894.8	326.0	480.9	247.8	335.0
Net income from cont. oper.	124.0	84.4	101.0	72.8	121.9
Funds from operations (FFO)	643.0	257.0	366.8	212.5	262.3
Capital expenditures	951.6	223.8	521.6	178.3	279.6
Free operating cash flow	(369.2)	(1.3)	(182.2)	17.5	(33.1)
Dividends paid	127.1	47.2	70.0	49.0	56.3
Discretionary cash flow	(496.3)	(48.4)	(252.2)	(31.5)	(89.4)
Cash and short-term investments	51.2	43.6	15.0	7.3	96.8
Debt	4,620.9	1,365.5	2,087.6	1,079.9	1,873.2
Preferred stock	125.6	36.1	0.0	0.0	0.0
Equity	3,132.2	1,109.2	1,498.7	790.3	1,413.3
Debt and equity	7,753.0	2,474.8	3,586.2	1,870.2	3,286.6
Adjusted ratios					
EBITDA margin (%)	27.4	20.7	27.1	21.3	33.0
EBIT interest coverage (x)	1.7	2.8	2.0	2.3	2.4
Return on capital (%)	5.7	7.6	6.8	8.4	6.3
FFO int. cov. (x)	3.2	4.2	3.6	3.6	3.6
FFO/debt (%)	13.9	18.8	17.6	19.7	14.0
Free operating cash flow/debt (%)	(8.0)	(0.1)	(8.7)	1.6	(1.8)
Discretionary cash flow/debt (%)	(10.7)	(3.5)	(12.1)	(2.9)	(4.8)
Net cash flow/capex (%)	54.2	93.8	56.9	91.7	73.7

Table 1.

Puget Energy Inc. -- Peer Comparison (cont.)					
Debt/EBITDA (x)	5.2	4.2	4.3	4.4	5.6
Total debt/debt plus equity (%)	59.6	55.2	58.2	57.7	57.0
Return on capital (%)	5.7	7.6	6.8	8.4	6.3
Return on common equity (%)	3.5	7.6	5.4	8.2	7.9
Common dividend payout ratio (unadj.; %)	95.5	54.2	71.0	67.3	46.3

Table 2.

Puget Energy Inc. -- Financial Summary						
	--12 months through Sept. 1--	--Fiscal year ended Dec. 31--				
	2011	2010	2009	2008	2007	2006
Rating history	BB+/Stable/--	BB+/Stable/--	BB+/Stable/--	BBB-/Watch Neg/--	BBB-/Watch Neg/--	BBB-/Stable/--
(Mil. $)						
Revenues	3,297.9	3,122.2	3,328.9	3,357.8	3,220.1	2,905.7
EBITDA	1,089.0	832.8	1,027.5	824.2	834.3	791.0
Net income from continuing operations	159.7	30.3	186.8	154.9	184.7	167.2
Funds from operations (FFO)	712.0	498.7	741.2	689.1	584.3	358.1
Capital expenditures	1,090.6	994.5	898.7	961.7	839.7	819.6
Dividends paid	127.0	113.0	129.9	138.4	112.8	104.3
Debt	5,447.2	5,204.5	4,692.7	3,965.5	3,473.9	3,628.2
Preferred stock	125.0	125.0	125.0	126.9	126.9	20.8
Equity	3,432.3	3,447.9	3,548.5	2,400.1	2,648.8	2,136.8
Debt and equity	8,879.5	8,652.4	8,241.1	6,365.6	6,122.7	5,765.0
Adjusted ratios						
EBITDA margin (%)	33.0	26.7	30.9	24.5	25.9	27.2
EBIT interest coverage (x)	1.5	1.1	2.1	2.0	2.0	2.1
FFO int. cov. (x)	2.8	2.4	3.4	4.3	3.3	2.6
FFO/debt (%)	13.1	9.6	15.8	17.4	16.8	9.9
Discretionary cash flow/debt (%)	(8.0)	(10.9)	(9.2)	(12.3)	(9.2)	(18.4)
Net cash flow/capex (%)	53.6	38.8	68.0	57.3	56.2	31.0
Debt/debt and equity (%)	61.3	60.2	56.9	62.3	56.7	62.9
Return on capital (%)	5.9	3.8	7.6	6.1	7.4	7.5
Return on common equity (%)	3.5	(0.0)	5.9	5.8	7.2	7.2
Common dividend payout ratio (unadj.; %)	74.1	344.1	64.9	83.7	58.7	62.4

Table 3.

Reconciliation Of Puget Energy Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

--Fiscal year ended Dec. 31, 2010--

Puget Energy Inc. reported amounts

	Debt	Shareholders' equity	Revenues	EBITDA	Operating income	Interest expense	Cash flow from operations	Cash flow from operations	Dividends paid
Reported	4,889.7	3,322.9	3,122.2	762.5	308.2	307.0	494.3	494.3	104.3
Standard & Poor's adjustments									
Operating leases	94.9	--	--	6.6	6.6	6.6	4.3	4.3	--
Intermediate hybrids reported as debt	(125.0)	125.0	--	--	--	(8.7)	8.7	8.7	8.7
Postretirement benefit obligations	38.2	--	--	(2.6)	(2.6)	--	(0.5)	(0.5)	--
Capitalized interest	--	--	--	--	--	14.2	(14.2)	(14.2)	--
Power purchase agreements	231.0	--	--	65.0	16.0	16.0	49.0	49.0	--
Asset retirement obligations	16.5	--	--	1.2	1.2	1.2	(2.3)	(2.3)	--
Reclassification of nonoperating income (expenses)	--	--	--	--	31.6	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	(40.6)	--
Debt (accrued interest not included in reported debt)	59.2	--	--	--	--	--	--	--	--
Total adjustments	314.8	125.0	0.0	70.2	52.8	29.3	45.0	4.4	8.7

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid
Adjusted	5,204.5	3,447.9	3,122.2	832.8	361.0	336.3	539.4	498.7	113.0

Table 4.

Puget Sound Energy Inc. -- Peer Comparison

	Puget Sound Energy Inc.	Avista Corp.	Portland General Electric Co.	NorthWestern Corp.	IDACORP Inc.
Rating as of Jan. 30, 2012	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	3,269.5	1,577.1	1,777.3	1,163.6	1,015.4
EBITDA	780.6	326.0	480.9	247.8	335.0
Net income from cont. oper.	116.0	84.4	101.0	72.8	121.9
Funds from operations (FFO)	668.6	257.0	366.8	212.5	262.3
Capital expenditures	925.6	223.8	521.6	178.3	279.6
Free operating cash flow	(275.2)	(1.3)	(182.2)	17.5	(33.1)
Dividends paid	177.7	47.2	70.0	49.0	56.3

Table 4.

Puget Sound Energy Inc. -- Peer Comparison (cont.)					
Discretionary cash flow	(452.9)	(48.4)	(252.2)	(31.5)	(89.4)
Cash and short-term investments	51.1	43.6	15.0	7.3	96.8
Debt	3,878.6	1,365.5	2,087.6	1,079.9	1,873.2
Preferred stock	125.6	36.1	0.0	0.0	0.0
Equity	2,894.7	1,109.2	1,498.7	790.3	1,413.3
Debt and equity	6,773.3	2,474.8	3,586.2	1,870.2	3,286.6
Adjusted ratios					
EBITDA margin (%)	23.9	20.7	27.1	21.3	33.0
EBIT interest coverage (x)	1.7	2.8	2.0	2.3	2.4
Return on capital (%)	5.2	7.6	6.8	8.4	6.3
FFO int. cov. (x)	3.8	4.2	3.6	3.6	3.6
FFO/debt (%)	17.2	18.8	17.6	19.7	14.0
Free operating cash flow/debt (%)	(7.1)	(0.1)	(8.7)	1.6	(1.8)
Discretionary cash flow/debt (%)	(11.7)	(3.5)	(12.1)	(2.9)	(4.8)
Net cash flow/capex (%)	53.0	93.8	56.9	91.7	73.7
Debt/EBITDA (x)	5.0	4.2	4.3	4.4	5.6
Total debt/debt plus equity (%)	57.3	55.2	58.2	57.7	57.0
Return on capital (%)	5.2	7.6	6.8	8.4	6.3
Return on common equity (%)	3.5	7.6	5.4	8.2	7.9
Common dividend payout ratio (unadj.; %)	148.1	54.2	71.0	67.3	46.3

Table 5.

Puget Sound Energy Inc. -- Financial Summary						
	--12 months through Sept. 1--	**--Fiscal year ended Dec. 31--**				
	2011	**2010**	**2009**	**2008**	**2007**	**2006**
Rating history	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2	BBB-/Watch Neg/A-3	BBB-/Watch Neg/A-3	BBB-/Stable/A-3
(Mil. $)						
Revenues	3,298.6	3,122.2	3,328.5	3,357.8	3,220.1	2,905.7
EBITDA	1,039.2	729.7	824.9	787.2	835.5	791.3
Net income from continuing operations	238.7	26.1	159.3	162.7	191.1	176.7
Funds from operations (FFO)	794.7	614.5	729.0	662.2	591.2	514.6
Capital expenditures	1,086.6	990.5	861.9	924.3	838.9	815.9
Dividends paid	214.5	195.5	187.4	150.2	112.8	109.8
Debt	3,962.5	4,044.7	3,563.3	4,027.7	3,489.6	3,615.5
Preferred stock	125.0	125.0	125.0	126.9	126.9	58.5
Equity	3,373.0	3,099.9	3,208.1	2,376.1	2,631.0	2,150.8
Debt and equity	7,335.5	7,144.6	6,771.4	6,403.8	6,120.6	5,766.3

Table 5.

Puget Sound Energy Inc. -- Financial Summary (cont.)						
Adjusted ratios						
EBITDA margin (%)	31.5	23.4	24.8	23.4	25.9	27.2
EBIT interest coverage (x)	2.3	1.1	2.0	1.9	2.0	2.2
FFO int. cov. (x)	4.2	3.4	4.1	4.0	3.3	3.3
FFO/debt (%)	20.1	15.2	20.5	16.4	16.9	14.2
Discretionary cash flow/debt (%)	(11.1)	(13.7)	(8.7)	(12.3)	(8.9)	(13.7)
Net cash flow/capex (%)	53.4	42.3	62.8	55.4	57.0	49.6
Debt/debt and equity (%)	54.0	56.6	52.6	62.9	57.0	62.7
Return on capital (%)	6.9	3.3	6.3	6.1	7.4	7.8
Return on common equity (%)	6.3	(0.1)	5.2	6.1	7.6	7.9
Common dividend payout ratio (unadj.; %)	86.2	715.6	115.0	89.6	56.7	62.1

Table 6.

Reconciliation Of Puget Sound Energy Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)									
	--Fiscal year ended Dec. 31, 2010--								
Puget Sound Energy Inc. reported amounts									
	Debt	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**
Reported	3,733.5	2,974.9	3,122.2	661.9	207.6	220.9	575.8	575.8	186.7
Standard & Poor's adjustments									
Operating leases	95.8	--	--	6.6	6.6	6.6	4.3	4.3	--
Intermediate hybrids reported as debt	(125.0)	125.0	--	--	--	(8.7)	8.7	8.7	8.7
Postretirement benefit obligations	38.2	--	--	(4.5)	(4.5)	--	6.7	6.7	--
Capitalized interest	--	--	--	--	--	14.2	(14.2)	(14.2)	--
Power purchase agreements	231.0	--	--	64.6	15.6	15.6	49.0	49.0	--
Asset retirement obligations	16.5	--	--	1.2	1.2	1.2	0.7	0.7	--
Reclassification of nonoperating income (expenses)	--	--	--	--	39.5	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	(16.5)	--
Debt (accrued interest not included in reported debt)	54.7	--	--	--	--	--	--	--	--
Total adjustments	311.3	125.0	0.0	67.8	58.3	28.8	55.2	38.7	8.7

Table 6.

Reconciliation Of Puget Sound Energy Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid
Adjusted	4,044.7	3,099.9	3,122.2	729.7	265.9	249.7	631.0	614.5	195.5

Ratings Detail (As Of February 24, 2012)

Puget Sound Energy Inc.	
Corporate Credit Rating	BBB/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated (1 Issue)	BB+
Senior Secured (21 Issues)	A-
Senior Unsecured (3 Issues)	BBB
Corporate Credit Ratings History	
16-Jan-2009	BBB/Stable/A-2
26-Oct-2007	BBB-/Watch Neg/A-3
13-May-2005	BBB-/Stable/A-3
Business Risk Profile	Excellent
Financial Risk Profile	Aggressive

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

Attachment 47.3

MOODY'S
INVESTORS SERVICE

SPECIAL COMMENT

Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities

Evaluating a Utility's Regulatory Framework

Table of Contents:

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Summary

The framework in which a regulated utility operates is typically one of its most significant credit considerations. The regulatory structure and its general framework is a primary consideration that differentiates the industry from most other corporate sectors.

The characteristics of a utility's regulatory framework represents one of four factors that are considered, within the context of Moody's Regulated Electric and Gas Utilities Rating Methodology, published August 2009, (the Rating Methodology) to determine its rating. This Special Comment discusses our scoring criteria on that first factor.

A key consideration in our analysis is the degree to which a utility's regulator has the ability to independently regulate within the context of its legal, legislative or political environment.

We also examine how developed the utility's regulatory framework is; the decision making track record of its regulators; the utility's business model; and its regulators' openness to alternative rate mechanisms that help assure timely cost recovery.

We also evaluate patterns of regulatory contentiousness, which is often driven by political intervention at some level, in an effort to develop a view toward regulatory bias. This is one of the more challenging aspects to our analysis, since political intervention often occurs quickly and unexpectedly. Ultimately, we look to evaluate how the act of balancing a utility's appropriate cost of service and return on investment with consumer's ability and willingness to pay may change over time. Today's economic turmoil appears to be having some implications for this assessment in selected jurisdictions.

In the U.S., the vast majority of utilities operate within state regulatory frameworks that are reasonably transparent and well developed where regulators generally strive for a fair balance in establishing rates that assure reliable service at a reasonable cost to ratepayers while allowing a utility a fair opportunity to earn a reasonable return. However, assessing this balance is a complex procedure, and frequently involves a subjective assessment on our part. While most utilities in the U.S. score within the Baa range on the regulatory framework factor, indicating relatively solid support from a credit perspective – there are a few notable exceptions.

In Asia, with the exception of Hong Kong, Singapore and Japan, the regulatory framework is generally less transparent, and regulators may be under political pressure to reduce or maintain rates. In Europe, utilities that fall under the subject Rating Methodology, do so either because their regulatory and market development has taken place somewhat later than other countries within the EU[1], or because they are somewhat isolated and have received an exemption to the EU Electricity Directive. In Canada, the provincial regulatory frameworks are well developed, transparent and predictable, and most utilities score in the A range on the regulatory framework factor. In Latin America, regulatory frameworks vary with some being stable and transparent while other are constantly shifting and prone to political intervention.

It is important to note that our evaluation of a utility's regulatory framework is company specific, and that the score assigned for Factor 1 considers management's ability, over time, to cultivate supportive regulatory relationships.

Introduction

When evaluating the credit quality of a utility, the degree of support that it may depend on from its regulators is typically one of Moody's most significant considerations. The regulatory framework is also the prime factor in differentiating the industry from most other corporate sectors. This is partly due to the fact that a typical utility provides services that are essential to our way of life and to our economy, namely the delivery of electricity and/or natural gas. Utilities typically do not compete with other companies for the ability to provide these services, although some highly structured pockets of competitive retail "supply" of electricity have been introduced across the U.S. As a monopoly, the activities of a utility are usually conducted within a legislatively mandated oversight framework – where the national, provincial or state regulatory commissions - can review costs associated with the need to provide consistently safe and reliable service, plus provide a reasonable profit. Consequently, a utility's total, over-all revenue requirements and the rates associated with generating those revenues, are important considerations in evaluating this factor.

As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality. The regulatory framework generally provides more certainty around a utility's cash flow and typically allows the company to operate with significantly less cushion in its cash flow metrics than comparably rated companies in other industrial sectors.

In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly. Because of the regulatory safety net, defaults are rare in this sector, as compared with most industrial companies. However, there have been seven major investor owned utility defaults in the United States over the last 50 years, five of which resulted in Chapter 11 bankruptcy filings. In five of the defaults, a dispute with regulators regarding an insufficient or delayed response to a request for financial relief associated with the recovery of costs and/or capital investment in utility plant is generally cited as a primary driver that led to growing financial pressure, credit rating downgrades and, in most cases, the eventual filing for bankruptcy.

[1] The EU Electricity Directive of 1999 ("the Directive") ushered in a period of liberalisation of generation and supply prices and hence most European vertically integrated utilities are covered under the Unregulated Utility and Power Companies Methodology

In our Regulated Electric and Gas Utilities Ratings Methodology, published August 2009, (the Rating Methodology) the importance of regulatory influence is emphasized by the 50% weighting [2] ascribed to various statutory and regulatory provisions when determining a utility's credit quality. Factor 1, Regulatory Framework, the first of four key factors, is ascribed a 25% weighting and considers the general regulatory and political environment under which a utility operates and the overall business position of a utility within that regulatory environment. Factor 2, Ability to Recover Costs and Earn Returns, is also ascribed a 25% weighting and addresses in a more specific manner the ability of an individual utility to recover its costs and earn a fair return on invested capital.

TABLE 1

Regulated Electric and Gas Utility Rating Methodology

KEY RATING FACTORS AND WEIGHTINGS
1. Regulatory Framework – 25%
2. Ability to Recover Costs and Earn Returns – 25%
3. Diversification – 10%
4. Financial Strength and Liquidity – 40%

Factors 1 and 2 are inter-related in numerous ways. For example, whereas Factor 2 evaluates a company's specific success at earning returns and generating adequate, predictable cash flows, possibly as a result of its use of recovery mechanisms, such as those for fuel and purchased power, environmental, renewable or other expenses, Factor 1 considers, among other things, the regulator's demonstrated willingness to authorize a use of enhanced recovery mechanisms and to provide an ability for the company to earn adequate returns. This Special Comment discusses how we calculate a utility's score for Factor 1 - Regulatory Framework. (The current Factor 1 scoring for the operating utilities in our rated universe is shown in Appendix A). These Factor 1 scores provide an indication of our current thinking. The scores are not intended to be static; they continue to be monitored and modified as warranted to reflect changing conditions and circumstances. In addition, when applied within the context of the Rating Methodology framework grid, the scores shown in Appendix A may be further modified by the use of a "strong" or "weak" designation.

What are the characteristics of a utility's regulatory framework?

In evaluating a utility's regulatory framework, we consider such things as the regulatory body's independence; its legislative or political environment; the extent of the regulatory framework's development; its track record for predictable, stable decisions; the utility's business model; and the openness of the regulators to alternative rate mechanisms that tend to provide additional assurance of timely cost recovery and the ability to earn a return on invested capital.

Regulatory Independence

A key consideration in assessing Factor 1 is the degree to which the regulator has the ability to act as an unbiased arbiter over the facts in the record, and base its decisions on the existing laws and statutory decisions. Today, balancing the sometimes conflicting goals of assuring a reliable supply of reasonably priced electricity or natural gas; assuring the long-term financial health of the utilities it regulates; and authorizing rate increases within a given state or region is increasingly viewed as challenging.

[2] The factor weightings shown in the rating methodology grid are approximate. The actual weight given to a factor in our assessment of an issuer's credit quality may differ based on the issuer's circumstances, and the scoring grid does not include every consideration that determines a rating.

We look to see if the regulator consistently strives to achieve balance, between the investor and the consumer in assessing the utility's rate request, or substantially denies the rate request by acting perhaps in a manner more akin to a consumer advocate.

We also evaluate the impact of outside political influence on the regulatory process, where a legislature or a governor can revise, amend or restructure certain provisions associated with the traditional, vertically integrated electric utility framework. Political influence works in many ways, from utility sponsored legislation on the positive side to wholesale reductions to recovery on the negative side.

The majority of utilities in the rated universe of the Rating Methodology are considered to have average exposure to regulator independence, meaning their regulators generally try to take the middle path. There are a few notable exceptions, for example, in Indonesia, or in Argentina where the politicization of the regulatory relationship tends to be a dominant factor in assigning a score to the regulatory framework factor.

National and local regulation

When a utility's revenues are determined by a single national regulator, within a well developed and transparent framework, Moody's generally views the framework as being more independent, less susceptible to local political influence and more supportive of long-term utility credit quality than state regulation. The difference in risk reflects our view that national regulation tends to be more transparent and sometimes even formulaic, and less exposed to significant political or consumer intervention. This tendency is best exemplified in markets that are large, well developed, and relatively transparent; such as the U.K or Japan.

In smaller markets, national regulators may also be susceptible to local pressure, In Asia, each country has one regulator, but with the exception of Hong Kong, Singapore and Japan, the regulatory framework is generally less transparent, and in some countries, the regulators are under political pressure to maintain or reduce rates.[3] The economic recession of the past few years has also put pressure on national regulators in Central and Eastern Europe as well.

In Latin America, the regulatory frameworks vary from one country to another, in some countries, such as Chile, utility regulatory frameworks have been in place for an extended period, and are quite transparent; for others, such as in Argentina, the frameworks are constantly shifting and subject to political influence, while in Brazil the frameworks are more developed but still evolving. Federally regulated utilities in Argentina, which serve the most densely populated areas of the country, tend to be more subject to public scrutiny than the local, smaller utilities in the interior of the country. As a result, regionally regulated utilities have been favored by rate increases more often and in a more timely manner than federally regulated utilities.

In Canada, the provincial regulatory frameworks are well developed, transparent and predictable. In addition, Canadian utilities generally have not pursued diversification strategies and have limited exposure to unregulated activities at affiliates or holding companies. We view Canada's business and regulatory environments as being more supportive than many of those in the U.S. Accordingly, most utilities in Canada score in the A range on the regulatory framework factor.

[3] For example, there has been limited tariff increases in Indonesia for the past few years and Malaysia kept its rates unchanged from 1999 to 2006.

We would be likely to assign a score of Aaa or Aa for a utility's regulatory framework factor in jurisdictions where regulators are likely to take extraordinary action to support a failing company,[4] or where a utility can set rates independently, like the U.S. owned Tennessee Valley Authority. Additionally, U.S.-based transmission companies, which enjoy formulaic federally regulated rates determined by the Federal Energy Regulatory Commission (FERC), but do not see extraordinary supportive action from their regulator, are currently scored in the Aa range because of the transparent and predictable characteristics of that framework.

U.S. Transmission Regulation

In an effort to encourage investment in the aging U.S. transmission infrastructure, the FERC established a transparent and supportive approach to establishing rates for significant transmission projects. Elements of this approach include:

» Authorized returns on invested capital that are generally higher than those awarded by state regulators;

» An ability to earn a cash return on construction work in progress;

» An ability to recover abandonment costs;

» A significant equity component is allowed in capital structures and companies have the ability to utilize double-leverage;

» No rate hearings required to adjust rates;

» Rates reset annually via established formula, assuring timely recovery of actual costs and return on investment;

» The rate formula may be forward looking.

In our opinion, state-regulated investor-owned U.S. utilities carry higher regulatory risk than utilities with rates regulated entirely by FERC. The U.S. market is highly fragmented: many utilities are exposed to overlapping or unclear regulatory jurisdictions, and to volatile power prices. And since state regulation is far more local, it can become political - particularly when significant rate increases are proposed. Currently, all state regulated U.S. investor-owned utilities receive scores that range from "A" to "Ba" for the regulatory framework factor.

We also acknowledge that a utility's operations are subject to regulation on numerous fronts, including operational safety and environmental controls. In these cases, federally or nationally imposed regulation, that does not consider local conditions, may create additional uncertainty or may result in a disproportionate impact for individual utilities.

Political tendencies

When a utility's rate setting process is exposed to significant political interference, its rate-case outcomes become less predictable, often resulting in reduced expectations for cash flow stability, and in many instances introducing a long-term period of contentiousness. Utilities with a history of politically charged rate proceedings will tend to score in the ranges of either Ba or B on the regulatory framework factor. We have observed that while utilities may ultimately prevail through legal

[4] This tends to be the case for utilities in Japan.

challenges, the process can take years to complete, and in most cases, the damage to credit quality will have already occurred.

In evaluating the potential for political interference in the U.S., we look beyond the method of commissioner selection (elected versus appointed). In our view, all regulation is political, so we do not differentiate in a significant manner how the commissioners got on the commission. In states where voters elect their regulatory commissioners, it might seem that consumer oriented political intervention - or a bias toward appearing to do everything possible to minimize rate increases, would be a heavy factor in rate case outcomes. In fact, while this is often the case, we have not found it to consistently be true.

Utilities in Arizona and New Mexico, where commissions are elected, have tended to experience protracted and highly publicized rate proceedings; as a result, utilities in these jurisdictions currently receive regulatory framework scores in the Ba range. Yet in numerous states with elected commissions such as Alabama, Georgia, North Dakota and South Dakota, utilities have not had a history of lengthy or politically charged rate proceedings. Many utilities in these states receive regulatory framework scores in the A range. It should be noted that a utility often represents one of the largest publicly-traded companies headquartered within a particular state that also employs a significant amount of the population with reasonably good jobs, is usually ascribed a substantial property tax bill and is often a very generous contributor to local charities.

On the other hand, the most significant recent examples of negative political intervention that posed a severe threat to utility credit has occurred within regulatory jurisdictions where commissioners were appointed, but their ability to act independently was impaired by the actions of politicians. We have seen this happen in recent years for utilities operating in Illinois and Maryland, which are now scored Ba on regulatory framework, but scored in the B range or lower amid threats of continued rate freezes or caps.

Utilities in California, which also has an appointed commission, faced extreme political opposition during the energy crisis of 2001-2002. Some of these utilities ultimately defaulted. This history is a key consideration in the score assigned to the regulatory framework for these companies; although for the past several years, the regulatory treatment for utilities in California has been among the more credit supportive observed for U.S. utilities, and until recently, their scores on Factor 1- Regulatory Framework remained within the Baa range. Currently, they are scored in the A category. In Florida, where the commission is appointed, utilities have historically experienced very supportive rate decisions, and those utilities had historically received scores in the A range. However, recent interventions by the Governor in the rate proceedings for Florida Power & Light and Progress Energy Florida - including the appointment of new commissioners in the midst of rate proceedings have contributed to our reassessment of this rating factor for these companies, resulting in lower regulatory framework scores for Factor 1 in the Baa range.

Outside of the U.S., utilities in Argentina provide a clear example of regulatory environments that are currently subject to a significant amount of political interference. Initially, ENARGAS was established as an independent agency to administer and enforce the Gas Act and applicable regulations for the gas distribution industry, including the tariff setting and periodic tariff review mechanisms. However, following the 2001-02 crisis, on July 2003 the Argentine government created a new agency (UNIREN or Agency to Renegotiate Public Utilities Contracts) to develop a common regulatory framework for all utilities and to renegotiate their tariffs. In addition, since May 2007 ENARGAS has been under an intervention decreed by the President, who appointed an official (or "Interventor") to be in charge of the agency. Therefore, many of the ENARGAS' technical duties are subject to political interference and as a consequence the regulatory framework is not transparent and highly unpredictable. As an example, Metrogas, an Argentine regulated LDC, has not been able to adjust its tariffs in over ten years, which has lead to a severe deterioration of the company's economic and financial situation. On June 17, 2010, the company filed for reorganization under Argentine law.

In some instances, political or legislative actions can, in fact, be supportive of utility credit quality – putting forth additional rate mechanisms or tools for state commissions to consider, or legislating specific time frames for rate decisions. Such actions generally offer the opportunity for a utility to receive more supportive treatment from its regulators, but they generally also require regulatory follow-through; and are typically not intended to impede the regulator's ability to balance the utility's need to recover its costs and earn a return with the desire to maintain reasonable rates. As a result, credit supportive legislative actions are generally less likely to immediately affect a utility's Regulatory Framework score.

Some political interventions have hurt utilities' credit quality

» When Illinois was preparing to fully transition to electric market rates for generation in 2006 and 2007, several bills were proposed that would re-freeze the electric rates for the state's primary utilities that had just come off a 10-year rate freeze. The bill's legislative progress caused considerable rate uncertainty – particularly since the regulator, the Illinois Commerce Commission, had already sanctioned power supply auctions for power procurement and approved rate phase-in plans. We considered the significant potential impact on utility cash flow as a major threat to credit quality which ultimately resulted in ratings downgrades to below investment grade for each of the Illinois transmission and distribution companies.

An August 2007 settlement avoided a more severe negative impact on the utilities' rates and credit ratings, and more recent regulatory proceedings have been concluded without direct political interference. However, this experience suggests the future possibility of political or consumer backlash if significant rate increases become necessary again . Moreover, the utilities' continued relationship with unregulated generation affiliates remains unchanged which was a primary motivation, in Moody's opinion, for the political pushback to transitioning to market rates for generation.

» Maryland also experienced a significantly politicized regulatory environment in 2006-2008 as its move towards electric retail competition became a major legislative and gubernatorial issue and was exacerbated by a potential acquisition of Constellation's Baltimore Gas & Electric Company (BG&E) utility subsidiary by Florida based FPL Group. New legislation produced significant uncertainty regarding electric utilities' ability to recover their increased costs for fuel and purchased power which ultimately resulted in significant deferrals and required refunds. Importantly, this legislation was passed after the Maryland Public Service Commission (MPSC) had already approved a plan that provided a more moderate deferral of rate increases. The legislature also voted to replace the full slate of MPSC commissioners - a highly unusual event.

During this time, the ratings of BG&E were downgraded by a total of three notches and remain at that level today. A spring 2008 settlement led to legislation that essentially resolved all issues; but not without a significant sustained reduction in BG&E's expected cash flow credit metrics. This relatively recent past experience, leads us to believe future political intervention cannot be entirely ruled out.

… while others have been supportive

» In Georgia, South Carolina and Florida, legislation has been enacted that permits utilities to earn a cash return on construction work in progress on nuclear plants. Moody's views this type of legislation positively as the resulting mechanisms provide support for a utility cash flows and credit metrics while significant construction is underway, and they also tend to reduce the potential for future rate shock.

» Michigan passed legislation in 2008 designed to reduce rate lag and encourage utility investment. In its 2009 and 2010 implementation of the legislation, the Michigan Public Service Commission appeared, in our opinion, to apply the legislation as intended; however, they also appeared to carefully balance the utilities' cost recovery needs with a need to minimize rate increases in a struggling economy. Such legislation has been a primary factor in the financial performance of the state's investor-owned utilities, given the severe economic contraction throughout the state.

Level of Development of the Regulatory Framework

Utilities that are operating within regulatory frameworks that are not well defined, or are relatively new, such as Eskom Holdings in South Africa, Israel Electric Corporation in Israel, Empresa Electrica de Guatemala S.A in Guatemala, and PLN in Indonesia will tend to receive lower regulatory framework scores, since a lack of development and track record reduces the level of predictability of rating outcomes and cash flow.

In Argentina, although a reasonable regulatory framework was established during the 1990's, and worked relatively well for almost 10 years, it was followed by a period of constant change of rules with very little support for the utilities' cost recovery requirements. In fact, for the past ten years, the majority of companies have been operating with frozen tariffs while costs continue to escalate. As a result of this high level of regulatory uncertainty and political intervention in the rate setting mechanism, the regulatory framework score for Factor 1 for all utilities in Argentina is in the B range.

Utilities in Brazil operate under a regulatory model that is well developed but with a relatively limited track record. The framework was implemented in 2004, and has generally evolved in a manner that has been supportive of utility investment and credit quality. Structural enhancements have included more efficient methods of power procurement, expansion of the national grid, centralization of long term energy planning, and increased thermoelectric capacity. Recognizing these improvements, in 2008 the regulatory framework score improved to Ba from B. However, the federal regulator is not fully independent of political pressure, and currently there is a fair amount of uncertainty surrounding the potential renewal or revocation of some utility concessions. As a result, the Factor 1 score for utilities in Brazil remains in the Ba range.

In certain instances, a utility's regulatory framework score could be tempered by the uncertain effects of policy changes (such as a transition to competition), or the implementation of new laws. As discussed above, Michigan in 2008 passed legislation enabling the Public Service Commission to give above-average support to its utilities - something which has proven to be beneficial in the current economic downturn. Even so, the improved regulatory environment is still relatively new and our concern about the sustainability of utility support in a continued weak economy holds Michigan utilities' regulatory framework scores in the Baa range.

Turnover among state regulatory commissioners may also increase the uncertainty surrounding rate case decisions. New commissioners often face challenges in quickly coming up to speed on complicated rate issues and obviously lack an established track record. Turnover that results from political intervention in opposition to rate increases, as we recently saw in Florida, is highly likely to have a negative impact on a utility's regulatory framework score.

Considerations within European Markets

The European utilities that fall under the Regulated Electric and Gas Utilities Rating Methodology, do so either because their regulatory and market development has taken place somewhat later than other countries within the EU or where they exist within isolated regimes where significant competition would be hard to achieve (such as the Portuguese regions of Azores and Madeira)[5] and hence have received an exemption to the Directive.

The regulatory frameworks that have been implemented in Central and East European (CEE) countries tend on the one hand to have benefited in the first place from the adaptation, albeit with some modifications, of the already well-established UK regulatory framework. However as the CEE utility markets have been historically rather fragmented, with varying speeds of liberalisation, the full application of a well defined, transparent and consistent regulatory mechanism does vary from region to region. The common factor affecting our evaluation of regulatory regimes in CEE is their short track record compared to the more established regulatory regimes in Western Europe.

In addition, the economic recession of the past two years, revealed a greater-than-expected political influence over the decisions of regulatory bodies even in the more developed CEE countries such as Poland or Slovakia. The adverse economic impacts of the recession raised the political pressures on regulatory regimes not only in the regions with historically highly politically-influenced regulation such as in South East Europe, but also resulted in increasingly politically and socially motivated decisions of historically more consistent and transparent regulatory regimes in Central Europe. Whilst certain regulatory decisions, such as the price cap established by the Slovak regulatory office across most of the regulated sectors or the reluctance of the Polish regulator to adjust tariffs during gas price hikes, have to be seen in the context of the extreme commodity price volatility recorded over the 2008-09 period, it appears that the independence of CEE regulatory regimes from political influence is still fragile and together with short track records prevents a high score on Factor 1.

Predictability and Stability

Utilities accustomed to fairly stable and predictable rate-proceeding outcomes tend to receive higher regulatory framework scores. This is heavily linked to the degree of a regulator's independence and how developed its framework is, but for utilities whose scores are not dominated by these factors, regulatory treatment over time may be a differentiating factor.

Regulation affects utility credit quality most directly by establishing prices (rates) for the electricity, gas and related services that the utility provides (revenue requirements), and by determining the authorized return on a utility's investment, as well as the authorized return to shareholders. In evaluating a utility's regulatory framework, we consider whether it has consistently been given rate increases that provides it an opportunity to recover its expenses and actually earn a rate of return in line with shareholder expectations.

Requested and authorized rates of return (ROEs) have trended downward over the last two decades, from about 12-13% in the early 1990s to the 10%-10.5% range more recently. Much of the decrease has stemmed from falling interest rates, but some of the decline may be attributed to other mechanisms put in place to ensure timely recovery and reduce risk (see next section). In evaluating the

[5] In this instance, they are subject to well-established Portuguese regulation under Entidade Reguladora dos Serviços Energéticos, where we apply a Baa to the Regulatory Framework

predictability of cash flows, we are concerned less with the awarded ROE, which has a tendency to become a headline, than the overall collective rate outcome, including the authorized base rate increase, the impact of any approved enhanced recovery mechanisms such as riders or trackers, and the implications for future cash flows. We observe that the amount of regulatory lag can be a contributing factor to a utility not being able to earn their authorized rate of return. From a credit perspective, while we are also less concerned with shareholder returns, we do observe that those companies that earn at or near their authorized rate of return tend to produce more predictable cash flows; and those companies that are not able to earn their authorized return tend to produce relatively weaker cash flow credit metrics.

The past two years have seen a tremendous amount of electric rate case activity, with rate increases generally coming in at slightly more than 50% of the requested amount. In prior years, when there was less activity, awards tended to be closer to 40%. Gas rate case awards, which have tended to be less politically contentious, have come in more consistently around 50%. While history tells us it is unlikely a utility would be awarded the full amount of its requested increase, companies that manage their regulatory relationships in a way that allows them to consistently achieve awards that provide an opportunity to earn a fair rate of return, would be more likely to receive an above average regulatory framework factor score.

Utilities that have received unwelcome surprises from regulators, with awards significantly lower than anticipated or less than enough to generally maintain or improve credit metrics, are likely to have a lower regulatory framework score. For example, the outlook of Consolidated Edison Company of New York (CECONY) was revised to negative and its ratings were ultimately downgraded following a change in our view of CECONY's historical relationship with its regulator and the extent to which we could expect future rate actions to be supportive of credit quality. In 2008, CECONY received a rate increase that was only about 35% of its requested amount, premised on a 9.1% ROE, which was significantly below the average ROE of 10% or so that was then typical for transmission and distribution utilities in other regulatory environments.

Alternative Rate Making Mechanisms

Another key aspect of a utility's regulatory framework is the regulator's openness to policies that could ease rate lag. Such policies could include the tendency for its rate cases to be settled rather than litigated over a protracted period, the use of interim rates and/or forward test years.

Other mechanisms are designed to assure cost recovery and give utilities the chance to earn allowed rates of return. These include such things as, pre-approval of recovery of investments for new generation, transmission or distribution; the inclusion of construction work in progress (CWIP) in utility rate bases; the existence of attrition revenues which provide cash returns on construction expenditures, the inclusion of riders or trackers for specific investments or expenses; and the design and administration of mechanisms that allow the recovery of prudently incurred costs for fuel and purchased power.

Where rate design reduces or eliminates the utility's exposure to fluctuations in gas or electricity consumption that can be caused by weather, economic conditions, gas or power costs or legislative or regulatory conservation requirements, the utility is likely to enjoy more stable revenue and cash flow than would otherwise be the case. This form of rate design, known as decoupling, tends to lower a utility's business risk and could contribute to higher scoring on Factor 1.

Although the impact of these factors on any given utility is considered more specifically when assigning scores to the second of the four factors utilized to determine utility credit quality, the ability to recover costs and earn returns, and as described more fully in Moody's Special Comment on Cost Recovery Provisions dated June 2010, to the extent these mechanisms have been a consistent part of the regulatory framework for some time it would also be considered positively when assigning a score to the regulatory framework factor.

A Utility's Business Model Could Affect Regulatory Framework Score

In evaluating the regulatory framework we also consider a utility's business model and its impact on its relationship with its regulators. We consider the amount and type of unregulated activity that a company may be engaged in as well as the nature of its regulated operations.

For utilities with some unregulated operations, we will look at the competitive and business position of these unregulated operations. Moody's views unregulated operations that have minimal or limited competition, large market shares, and statutorily protected monopoly positions as having substantially less risk than those with smaller market shares or in highly competitive environments. Those businesses with the latter characteristics usually face a higher likelihood of losing customers, revenues, or market share. For utilities with a significant amount of such unregulated operations, a lower score could be assigned to this factor than would be the case if the utility had solely regulated operations.

We also consider the degree to which a utility might be indirectly exposed to unregulated business risks by virtue of the ownership of such businesses by affiliates or parent holding companies. We will consider the tendency of parent companies to pursue diversification strategies which, in the absence of effective ring-fencing mechanisms, could expose the regulated utility to increased financial risk. Historically, holding company diversification into unregulated, and sometimes unrelated, business lines and into international markets has had generally negative credit consequences for regulated utility subsidiaries.

We also evaluate the nature of the utility's regulated businesses. Local Gas Distribution Companies sometimes referred to as LDCs, are generally considered to have lower business risk than electric utilities. These utilities tend to almost universally have mechanisms in place that pass the commodity cost of gas directly to their customers, tend to have capital expenditure plans that are more consistent than electric utilities, reducing the need for large sudden rate increases; and tend to have less contentious issues with their regulators. Decoupling, a concept designed to protect a utility from the risk of declining usage, has become more prevalent in recent years as regulators have sought to encourage energy efficiency, and is currently much more prevalent in gas utilities. Therefore, LDCs could receive higher scores on the regulatory framework factor than electric utilities operating within the same jurisdiction.

In jurisdictions that have deregulated power generation activities, utilities have been left with only a delivery obligation, giving them - in theory - a lower business risk profile as they are not exposed to the costs and operating risks associated with power production. However, in many deregulated markets, the utility maintains a provider of last resort (POLR) obligation, and may be subject to rate caps or freezes that do not always allow the full timely recovery of costs for power purchased or hedged to meet their POLR obligations. A utility that provides only transmission and distribution services, and truly has no exposure to retail customers, is viewed as having a lower business risk profile and its regulatory framework would likely score above average. This is true for the majority of the transmission and distribution utilities operating in Texas, the Factor 1 scores for these companies are in the A range. Conversely, utilities with significant POLR and under-recovery risk tend to score below average.

Vertically integrated electric utilities are generally considered to have higher business risk than T&D utilities due to the risks associated with generation including fuel price and volume, operational and environmental risks. Among utilities with generation, those with significant exposure to fossil fuels, particularly coal, are typically viewed as having higher risk due to uncertainty as to the timing and amount of capital expenditures required to comply with further anticipated restrictions on environmental emissions including carbon dioxide, mercury, sulfur dioxide and nitrogen oxides.

Regulatory Framework Score is Utility Specific

It is important to note that our evaluation of a utility's regulatory framework is company specific, considering each company's experience and track record at cultivating supportive regulatory relationships and operating within its framework. Although utilities operating within the same framework will tend to have similar Factor 1 scores, it is possible to have deviations based on actual experience. For example:

In Florida, a historically supportive environment, Progress Energy Florida, Inc. and Florida Power & Light's recent sizeable rate increase requests, which were proposed against a backdrop of a significantly weakened economy, resulted in an unprecedented (for Florida) amount of political intervention, and rate increases that were severely limited, or denied. As a result, we have lowered the Factor 1 score for these companies to Baa from A. This does not necessarily mean that we would automatically lower the regulatory framework scores for all utilities in Florida to the same degree. Gulf Power Company, for example, which has not filed for a base rate increase in several years and is not expected to do so over the near term, is insulated to some extent from the current, perhaps temporarily deteriorated, political and regulatory environment in the state.

In Virginia, a regulatory environment also historically viewed as supportive, legislation passed in 2007 essentially to re-regulate the electric industry has impacted utilities differently. Virginia Electric and Power Company (VEPCO), in March received commission approval of a unanimous settlement agreement, which included a base rate ROE of 11.9%. The settlement resulted in no change in VEPCO's base rates (but did require significant refunds and rate credits); however, it also allows VEPCO to adjust rates via rider mechanisms for various transmission, generation and efficiency investments. As a result, cash flows are expected to remain adequate and VEPCO's Factor 1 score is currently A. On the other hand, in 2008 the commission rejected Appalachian Power Company's (APCO) proposed construction of an integrated gas combined cycle plant, and associated request for a premium ROE. In APCO's pending rate case, staff is recommending an increase of approximately $40 million, while a new state law resulted in the suspension of a $154 million interim increase put in place in December. APCO also has operations in West Virginia and its score on Factor 1 is currently Baa. Allegheny Energy Inc.'s Potomac Edison Company (PEC) had substantial difficulty recovering its increased costs for fuel and purchase power post a June 2007 expiration of a fixed rate contract with its affiliate. Recovery was not authorized until 2008, and was implemented, subject to caps, in July 2009. On June 1st, PEC completed of the sale of its Virginia operations to two electric cooperatives.

A utility's treatment within its regulatory framework, and our assessment of its Factor 1 score, often may have less to do with the regulator and much to do with the company and their cultivation of the regulatory relationship. It is entirely possible for a company to improve upon its regulatory relationships via open communication and negotiation toward the shared goals of providing reliable service at a reasonable cost. For example, regulatory relationships within PacifiCorp's numerous jurisdictions have generally all improved since its 2006 acquisition by MidAmerican Energy Holdings, Inc. as the company focused on understanding the needs and concerns of the regulators and other constituents within each state that it operates.

Other Considerations

On a company-specific basis, we would also evaluate factors such as the regulator's ability to oversee and ultimately approve utility mergers and acquisitions or their ability to encourage or require investments in renewable resources or energy efficiency. Environmental regulations, such as carbon capture or renewable portfolio standards could affect the regulatory framework score, particularly if they are especially onerous, for example in the U.S. southeast where renewable resources are limited. Nevertheless, these mandates are complex, usually have voluntary alternatives or offset provisions and can simply be re-legislated in the future which typically does not make these requirements a material credit issue at this time.

We also look at the substance of any regulatory or legal ring fencing provisions, including restrictions on dividends, capital expenditures and investments; separate financing provisions and/or legal structures; and limits on the ability of the regulated entity's ability to support its parent in times of financial distress. At any given time, depending on the circumstances facing the company, these may become contributing factors in determining the Factor 1 score.

Conclusion

A utility's regulatory framework is a key consideration in determining its credit quality - accounting for a significant 25% weighting - when we evaluate a utility's credit rating within the framework of our Rating Methodology.

When evaluating a utility's regulatory framework we consider such things as the independence of the regulatory body; the legislative or political environment; how developed the regulatory framework is; the regulator's track record for predictability and stability in terms of decision making; the business model of the utility; and the regulator's openness to consider alternative rate mechanisms.

Most of the utilities we rate operate in environments where regulators strive for a fair balance between assuring reliable customer service at a reasonable cost, while allowing a utility to earn a reasonable return. These companies generally score around the mid-Baa range.

Meanwhile, unusual regulatory conditions can affect a utility's credit rating for better or worse. Utilities operating in regulatory environments with a history of independent decision making and generally supportive regulatory actions receive the highest regulatory framework scores; generally within the A to Aa ranges – while those operating in environments prone to political pressure receive the lowest scores, generally within the B to Ba ranges.

Appendix A: Current Factor 1 scoring for the operating utilities in Moody's rated universe

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
Chubu Electric Power Company, Incorp.	CLP Power Hong Kong Limited	Alabama Power Company	Appalachian Power Company	Arizona Public Service Company	National Power Corporation
Chugoku Electric Power Company, Incorp.		ALLETE, Inc.	Avista Corp.	Cemig Geraçao e Transmissao	Power Sector Asset & Liabilities Management
Hokkaido Electric Power Company, Incorp.		Duke Energy Carolinas, LLC	Black Hills Power, Inc.	Companhia Energetica de Minas Gerais	Perusahaan Listrik Negara (P.T.)
Hokuriku Electric Power Company		FortisBC Inc	Central Vermont Public Service Corp.	Companhia Paranaense de Energia	
Kansai Electric Power Company, Incorp.		Georgia Power Company	Cleco Power LLC	EDP – Energias do Brasil	
Kyushu Electric Power Company, Incorp.		Hydro-Quebec	Columbus Southern Power Company	Empire District Electric Company (The)	
Okinawa Electric Power Company, Incorp.		Interstate Power & Light Company	Consumers Energy Company	Empresas Publicas de Medelin E.S.P.	
Tokyo Electric Power Company, Incorp.		Madison Gas and Electric Company	Dayton Power & Light Company	Eskom Holdings Ltd	
Tennessee Valley Authority		MidAmerican Energy Company	Detroit Edison Company (The)	Furnas Centrais Eletricas S.A	
		Mississippi Power Company	Duke Energy Indiana, Inc.	Israel Electric Corporation Limited (The)	
		Northern States Power Company (Minnesota)	Duke Energy Kentucky, Inc.	Kansas City Power & Light Company	
		Northern States Power Company (Wisconsin)	Duke Energy Ohio, Inc.	Light S.A.	
		Otter Tail Power Company	Eesti Energia AS	Monongahela Power Company	
		Progress Energy Carolinas, Inc.	EDA - Electricidade dos Acores, S.A.	NTPC Limited	
		South Carolina Electric & Gas Company	El Paso Electric Company	Public Service Company of New Mexico	
		Southern California Edison Company	Empresa de Electricidade da Madeira, S.A.	Tata Power Company Limited (The)	
		Pacific Gas & Electric Company	Entergy Arkansas, Inc.	Tucson Electric Power Company	
		San Diego Gas & Electric Company	Entergy Gulf States Louisiana, LLC	Union Electric Company	
		Virginia Electric and Power Company	Entergy Louisiana, LLC	UNS Electric	
		Wisconsin Electric Power Company	Entergy Mississippi, Inc.		
		Wisconsin Power and Light Company	Entergy New Orleans, Inc.		
		Wisconsin Public Service Corporation	Entergy Texas, Inc.		
			Florida Power & Light Company		
			Green Mountain Power Corporation		
			Gulf Power Company		
			Hawaiian Electric Company, Inc.		
			Idaho Power Company		
			Indiana Michigan Power Company		
			Indianapolis Power & Light Company		

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
			Kentucky Power Company		
			Kentucky Utilities Co.		
			Korea Electric Power Corporation		
			Korea East-West Power Co. Ltd		
			Korea Hydro and Nuclear Power Co. Ltd		
			Korea Midland Power Co. Ltd		
			Korea South-East Power Co. Ltd		
			Korea Southern Power Co. Ltd		
			Korea Western Power Co. Ltd		
			Latvenergo AS		
			Louisville Gas & Electric Company		
			Nevada Power Company		
			Northern Indiana Public Service Company		
			NorthWestern Corporation		
			Ohio Power Company		
			Oklahoma Gas & Electric Company		
			PacifiCorp		
			Portland General Electric Company		
			Progress Energy Florida, Inc.		
			Public Service Company of Colorado		
			Public Service Company of New Hampshire		
			Public Service Company of Oklahoma		
			Puget Sound Energy, Inc.		
			San Diego Gas & Electric Company		
			Sierra Pacific Power Company		
			Southern Indiana Gas & Electric Company		
			Southwestern Electric Power Company		
			Southwestern Public Service Company		
			Tampa Electric Company		
			Tenaga Nasional Berhad		

T& D Utilities

Aa	A	Baa	Ba	B
Hong Kong and China Gas Co. Ltd	AEP Texas Central Company	Atlantic City Electric Company	AES Eletropaulo	Empresa Distribuidora Norte S.A.
Oman Power and Water Procur. Co.	AEP Texas North Company	Central Hudson Gas & Electric Corporation	AES El Salvado Trust	Empresa Jujena de Energia S.A.
	CenterPoint Energy Houston Electric, LLC	Central Maine Power Company	Baltimore Gas and Electric Company	
	FortisAlberta Inc.	Cleveland Electric Illuminating Company (The)	Bandeirante Energia S.A.	
	Hydro One Inc.	Connecticut Light and Power Company	Cemig Distribuição S.A.	
	Newfoundland Power Inc.	Consolidated Edison Company of New York	Centrais Eletricas do Para S.A.	
	Oncor Electric Delivery Company	Jersey Central Power & Light Company	Centrais Eletricas Matogrossenses S.A.	
	Superior Water, Light and Power Company	Massachusetts Electric Company	Central Illinois Light Company	
	Texas-New Mexico Power Company	Metropolitan Edison Company	Central Illinois Public Service Company	
		Narragansett Electric Company	Commonwealth Edison Company	
		New England Power Company	Comp. de Ener. Eletr. do Est. do Tocantins	
		New York State Electric and Gas Corporation	Delmarva Power & Light Company	
		Niagara Mohawk Power Corporation	Duquesne Light Company	
		NSTAR Electric Company	Empresa Electrica de Guatemala, S.A.	
		Ohio Edison Company	Energisa Paraíba-Dist. de Energia S.A.	
		Orange and Rockland Utilities, Inc.	Energisa Sergipe - Dist. de Energia S.A.	
		PECO Energy Company	Escelsa	
		Pennsylvania Electric Company	GAIL (India) Ltd	
		Pennsylvania Power Company	Illinois Power Company	
		PPL Electric Utilities Corporation	Light Serviços	
		Public Service Electric and Gas Company	Perusahaan Gas Negara	
		Rochester Gas & Electric Corporation	Potomac Edison Company (The)	
		Toledo Edison Company	Potomac Electric Power Company	
		United Illuminating Company	Rede Energia	
		West Penn Power Company	Rio Grande Energia S.A. - RGE	
		Western Massachusetts Electric Company	Towngas China Co. Ltd	
			Xinao Gas Holdings Ltd	

Transmission Only Utilities

Aa
American Transmission Company LLC
American Transmission Systems
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company
Trans-Allegheny Interstate Line Company

Local Gas Distribution Companies (LDCs)

Aa	A	Baa	Ba	B
Terasen Gas Inc.	Atlanta Gas Light Company	Bay State Gas Company	Cia de Gas de Sao Paulo - COMGAS	Camuzzi Gas Pampeana S.A.
	Piedmont Natural Gas Company, Inc.	Berkshire Gas Company	Source Gas LLC	Gas Natural Ban S.A.
	Public Service Co. of North Carolina, Inc.	Boston Gas Company	UNS Gas	Metrogas S.A.
	Southern California Gas Company	Brooklyn Union Gas Company		
	Terasen Gas (Vancouver Island) Inc.	Cascade Natural Gas Corp.		
	Wisconsin Gas LLC	Colonial Gas Company		
		Connecticut Natural Gas Corporation		
		Indiana Gas Company, Inc.		
		Laclede Gas Company		
		Michigan Consolidated Gas Company		
		New Jersey Natural Gas Company		
		North Shore Gas Company		
		Northern Illinois Gas Company		
		Northwest Natural Gas Company		
		Peoples Gas Light and Coke Company		
		SEMCO Energy, Inc.		
		South Jersey Gas Company		
		Southern Connecticut Gas Company		
		Southwest Gas Corporation		
		UGI Utilities, Inc.		
		Washington Gas Light Company		
		Yankee Gas Services Company		

Moody's Related Research

Rating Methodologies:

» Regulated Electric and Gas Utilities, August 2009 (118481)

» Unregulated Utilities and Power Companies, August 2009 (118508)

Industry Outlooks:

» U.S. Electric Utilities Face Challenges Beyond Near-Term, January 2010 (121717)

Special Comments:

» Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality, June 2010 (122304)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

» contacts continued from page 1

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MOODY'S
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MOODY'S INVESTORS SERVICE

SPECIAL COMMENT

Canadian Rate-Regulated Entities Considering Conversion to U.S. GAAP – Ratings Unlikely to be Impacted

Table of Contents:

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Summary

Effective January 1, 2011, most publicly-traded Canadian enterprises are required to prepare their financial statements using International Financial Reporting Standards (IFRS).

IFRS is problematic for rate-regulated utilities as its lack of specific guidance for accounting for rate-regulated activities (regulatory accounting) is expected to result in de-recognition of some or all regulatory assets and liabilities and increased volatility in reported earnings and equity.

The Canadian Accounting Standards Board (AcSB) has allowed qualifying rate-regulated utilities to defer conversion to IFRS by one year, i.e. January 1, 2012.

Many Canadian regulated utilities have availed themselves of the deferral option. Of those, many are considering, or have already opted for, conversion to U.S. GAAP (rather than IFRS) effective January 1, 2012.

To the extent that Canadian rate-regulated entities convert to U.S. GAAP, we do not expect that change alone to impact credit ratings for a number of reasons:

» normally, a change in the medium of communicating financial results should not significantly impact the underlying economic position of an entity and our credit analysis focuses on economic substance rather than financial reporting;

» our analysis of utility financial condition focuses on cash flow-based metrics and cash flow should not be significantly different regardless of the choice of financial reporting principles; and

» we make standard and non-standard adjustments to reported financial data as required to minimize or eliminate accounting noise regardless of which system of accounting principles an issuer utilizes.

Background - Cananda's Adoption of IFRS

In February 2008, the AcSB announced that Canadian GAAP will cease to exist for all Canadian publicly accountable enterprises[1] (PAEs). Most PAEs are required to adopt IFRS for periods beginning on or after January 1, 2011. Qualifying entities with rate-regulated activities, investment companies, and segregated accounts of life insurance enterprises are permitted to defer IFRS adoption to periods beginning on or after January 1, 2012. In addition, Canadian enterprises that are registered with the U.S. Securities and Exchange Commission (SEC) can elect to prepare their financial statements in accordance with U.S. GAAP.

Many Canadian rate-regulated entities (electric utilities, gas distribution utilities and pipelines) have announced that they will defer IFRS adoption until January 1, 2012 and many of those are considering, or have already opted for, conversion to U.S. GAAP rather than IFRS, see Appendix I.

Regulatory Accounting Not Available Under IFRS

We believe the preference for U.S. GAAP over IFRS is due to the absence of regulatory accounting under current IFRS. Existing Canadian and U.S. GAAP both provide specific guidance for rate-regulated entities that allows these companies to defer certain costs and revenues and create regulatory assets and liabilities where the regulatory construct provides for such deferrals as well as the ultimate recovery or refund of those amounts.

While the International Accounting Standards Board (IASB) has studied the possibility of introducing rate-regulated accounting under IFRS for a number of years, in September 2010, it deferred any further study of the issue. Accordingly, there is currently no guidance for rate-regulated entities under IFRS and it is uncertain whether there will be any guidance prior to January 1, 2012 when the one year deferral option ends.

Regulatory accounting reduces the volatility in reported net income and equity that would occur in the absence of rate-regulation and regulatory accounting. Without regulatory accounting, a utility would not be able to defer the recognition of recoverable costs even if future recovery of those costs is expected under the utility's regulatory framework. The income and equity smoothing effect of regulatory accounting is important to rate-regulated entities, particularly those that are publicly traded companies or subsidiaries thereof. Equity analysts tend to consider net income as an important driver of utility stock valuation and we believe that management teams would prefer to avoid the additional stock price volatility that could result from the absence of regulatory accounting.

The potential for greater volatility in reported net income and equity also has implications for those companies whose credit agreements or trust indentures contain financial covenants that make reference to reported income or equity measures. While we would expect most utilities to be able to negotiate amendments to their bank credit agreements to minimize or eliminate the risk of covenant breaches caused by a change in financial accounting standards, amending bond indentures can be a more challenging undertaking.

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[1] A publicly accountable enterprise is an entity, other than a not-for-profit organization, or a government or other entity in the public sector, that:

» has issued, or is in the process of issuing, debt or equity instruments that are, or will be, outstanding and traded in a public market (a domestic or foreign stock exchange or an over-the-counter market, including local and regional markets); or

» holds assets in a fiduciary capacity for a broad group of outsiders as one of its primary businesses.

Furthermore, regulatory accounting is consistent with the manner in which regulators set the rates that utilities can charge their customers. As such, utilities are able to maintain a single set of financial statements that can be used for both financial reporting purposes and regulatory rate-making purposes. In the absence of regulatory accounting, rate-regulated entities might have to maintain two sets of financial statements - one for financial reporting purposes and one for regulatory rate-making purposes.

We note that to the extent that Canadian utilities switch to U.S. GAAP rather than IFRS, they might simply be kicking the can down the road a few years given the ongoing convergence efforts between IFRS and U.S. GAAP. The U.S. has been considering the adoption of IFRS for a number of years and the SEC is expected to make a further pronouncement in this regard during 2011. In addition, convergence between these two accounting standards began a number of years ago and continues apace even as the U.S. grapples with the question of the outright adoption of IFRS. That said, if and when the U.S. ultimately decides to adopt IFRS, it is possible, although by no means certain, that the IASB will have finalized its deliberations on regulatory accounting and decided to adopt regulatory accounting.

Transition to Either IFRS or U.S. GAAP Unlikely To Impact Ratings of Canadian Rate-Regulated Entities

Regardless of the choice of either IFRS or U.S. GAAP, we expect that the ratings of Canadian utilities would not be impacted by the change in accounting principles alone.

As we have previously stated in our research, a change in the medium of communicating financial results should not significantly impact the underlying economic position of an entity. Importantly, it is our assessment of an issuer's fundamental economic condition and prospects, rather than its reported financial position, that drives our opinion of relative credit strength.

Additionally, the rating methodologies we apply to rate-regulated entities (Regulated Electric and Gas Utilities, Natural Gas Pipelines and Midstream Energy) tend to focus on cash flow metrics which should not be materially different regardless of the choice of accounting principles. We would not expect any significant changes in investing, financing and operating cash flows as a result of a change in accounting principles.

Furthermore, we routinely make various standard and non-standard adjustments to reported financial data as required to minimize or eliminate accounting noise regardless of which system of accounting principles an issuer utilizes.

In the absence of regulatory accounting, utilities would not be able to defer the recognition of recoverable costs even if the regulator has approved their recovery. This would cause reported net income and equity to be more volatile than they would be under regulatory accounting. From a credit perspective the loss of regulatory accounting would not be expected to significantly impact cash flows, and therefore credit metrics. However, without regulatory accounting, the transparency of current and potential future cash flows would be greatly reduced. For example, the operating activities section of the Cash Flow Statement would no longer identify cash flows associated with the creation, recovery or refund of regulatory assets and liabilities. Since the creation and recovery/refund of regulatory deferrals are typically not recurring components of cash flow, reported cash from operating activities would be a less useful indicator of sustainable cash generation in future periods. We believe it is this reduced transparency of cash flows and the increased volatility of net income and equity under IFRS that make U.S. GAAP a more attractive alternative for some Canadian utilities.

Regardless of their choice of U.S. GAAP or IFRS, we expect Canadian utilities to make an orderly transition to their new financial reporting standard. This should allow users of financial statements to clearly understand the impact of the transition on the company's reported results and financial position, together with the wider consequences of adoption. The latter includes matters such as the impact (if any) on tax affairs, business strategy, customer relationships, regulatory compliance, and on internal control processes.

As we have noted in prior research, the single largest transition to IFRS to date, in the European Union in 2005, did not result in any direct rating changes. We generally found that our key credit metrics, after applying our standard analytical adjustments and reversing some of the less helpful consequences of the transition, were not significantly impacted by the accounting change.

Comparability of Reported Financial Results

Although conversion to U.S. GAAP (as opposed to IFRS) would reduce the comparability of the reported financial results of Canadian rate-regulated issuers to those of their peers outside of North America, it would increase the comparability of the reported results of Canadian and U.S. utilities.

Although historically Canadian and U.S. GAAP have been quite similar, there have been differences in areas such as accounting for joint ventures. For Canadian rate-regulated entities adopting U.S. GAAP, such differences would cease to exist. Also, recognizing the historic similarities between U.S. and Canadian GAAP, the comparability of future and historic reported financial results for companies adopting U.S. GAAP would likely be greater than for those companies adopting IFRS.

That said, our credit assessments focus on adjusted rather than reported financial results. Accordingly, the comparability of reported results is less relevant to our credit analysis provided that the issuer's overall disclosure is sufficiently robust to allow us to make our standard adjustments as well as any necessary non-standard adjustments.

Other Considerations in Analyzing Effects of Transition

While current Canadian and U.S. GAAP are substantially similar, it is nevertheless important to be aware that a few differences between the two could sway reported credit metrics on transition. Examples of GAAP differences that could be material to reported credit metrics are as follows:

In accounting for joint ventures, Canadian GAAP requires proportionate consolidation method of accounting[2], while U.S. GAAP requires equity method of accounting[3]. While this may not affect significantly the entity's net assets or net income, it will change numerous individual line items on its balance sheet and income statement, having potentially pervasive effect on its reported credit metrics. Moreover, under U.S. GAAP, guarantees of joint venture debt may have to be reflected on the balance sheet where they weren't previously under Canadian GAAP.

2 Under this method, each venturer's share of each of the assets, liabilities, income and expenses of a jointly controlled entity is combined line by line with similar items in venturer's financial statements.

3 Under this method, the investment in joint venture is recorded as one line item on the balance sheet, is initially measured at cost, and is adjusted thereafter for post-acquisition changes in the investor's share in net assets of the investee.

Commodity inventories are recorded at fair value under Canadian GAAP, while U.S. GAAP requires them to be measured at lower of the original cost or the current replacement cost. This difference could result in different measurements of inventories and cost of sales on transition.

Unlike Canadian GAAP, U.S. GAAP requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan as an asset or liability. While this may change the reported defined benefit obligation on transition, this difference should have no bearing on credit metrics after application of Moody's standard adjustments related to benefit plans.

Appendix I – Canadian Utilities Planned Conversion Strategies

Previously Converted to U.S. GAAP

Issuer	Senior Unsecured Rating and Outlook
Emera Inc.	Unrated
Nova Scotia Power Inc.	Unrated

Deferring IFRS Conversion and Considering Adopting U.S. GAAP effective January 1, 2012

Issuer	Senior Unsecured Rating and Outlook
AltaGas Ltd.	Unrated
Enbridge Inc.	Baa1, stable
Enbridge Gas Distribution Inc.	Unrated
Enbridge Pipelines Inc.	Unrated
FortisAlberta Inc.	Baa1, stable
Fortis Inc.	Unrated
FortisBC Holdings Inc. (formerly Terasen Inc.)	Baa2, stable
FortisBC Inc.	Baa1, stable
FortisBC Energy Inc. (formerly Terasen Gas Inc.)	A3, stable
Newfoundland Power Inc.	Baa1, stable (Issuer Rating)
NOVA Gas Transmission Limited	A3, stable
TransCanada Corporation	Baa1, stable
TransCanada PipeLines Limited	A3, stable

Deferring IFRS Conversion to January 1, 2012

Issuer	Senior Unsecured Rating and Outlook
Enbridge Income Fund	Baa2, stable
Hydro One Inc.	Aa3, stable
Toronto Hydro Corporation	Unrated
Union Gas Limited	Unrated
Westcoast Energy Inc.	Unrated

Deferring IFRS Conversion and Maintaining Two Sets of Books Effective January 1, 2012

Issuer	Senior Unsecured Rating and Outlook
Pacific Northern Gas	Unrated

Reporting in Accordance With IFRS Effective January 1, 2011

Issuer	Senior Unsecured Rating and Outlook
AltaLink L.P.	Unrated
Canadian Utilities Limited	Unrated
CU Inc.	Unrated
EPCOR Utilities Inc.	Unrated
Hydro-Québec	Aa2, stable

Moody's Related Research

For additional discussion of our views regarding IFRS, please refer to the following reports:

Special Comments:

» Analyzing the Canadian IFRS Transition for Non-Financial Corporations, December 2010 (129465)

» The SEC's IFRS Progress Report Offers a Glimpse of What's to Come, November 2010 (128742)

» Impact of Accounting Convergence in Japan: from Japanese GAAP to IFRS, July 2010 (126259)

» Are We Better Off Under IFRS?, November 2008 (111906)

» Guideline Rent Expense Multiples for Use with Moody's Global Standard Adjustment to Capitalize Operating Leases, February 2006 (96830)

Sector Comments:

» U.S. Public Companies' Transition to International Accounting Standards Hangs in the Balance, March 2010 (123439)

» Prominent International Advisory Group Issues Recommendations to Accounting Standard-Setters, August 2009 (119315)

» Comment Period for IFRS Roadmap Ends Today -- What's Next?, April 2009 (116827)

Rating Implementation Guidance:

» Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations - Standardized Adjustments to Improve Global Consistency, December 2010 (128137)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Report Number: 131730

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Global Credit Portal
RatingsDirect®

March 12, 2010

Standard & Poor's Updates Its U.S. Utility Regulatory Assessments

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Standard & Poor's Updates Its U.S. Utility Regulatory Assessments

In Standard & Poor's Ratings Services' commentary "Assessing U.S. Utility Regulatory Environments," (re-published March 11, 2010 on RatingsDirect), we discussed our views on what constitutes a credit-supportive regulatory climate. We then used those factors to create assessments of the regulatory environments in states that regulate the electric and gas utilities that we rate. We based the assessments of relevant jurisdictions on quantitative and qualitative factors, focusing on four main categories: the basic regulatory paradigm employed in the jurisdiction, ratemaking procedures, political influence, and financial stability.

The table and map below show our updated assessments of regulatory jurisdictions.

We lowered Florida to "Credit-Supportive" from "More Credit-Supportive" to incorporate our opinion regarding what we view to be a higher degree of political influence in more recent regulatory decisions. Connecticut was lowered to "Less Credit-Supportive" from "Credit-Supportive" in response to a series of apparently precedent-setting rate case decisions that, in our opinion, may make it more difficult for utilities to earn a reasonable return. Hawaii was lowered to "Less Credit-Supportive" from "Credit-Supportive" because of worsening regulatory lag and uncertainties we see regarding the realization of the Clean Energy Initiative's goals given the time it is taking to issue key decisions.

We raised Oklahoma to "Credit-Supportive" from "Less Credit-Supportive" based on our assessment of the addition of several new ratemaking mechanisms now used in the state that we believe will significantly enhance rate timeliness and cost recovery. Illinois was raised to "Less Credit-Supportive" from "Least Credit-Supportive" based on what we view as a return to stability in the legislative and regulatory environment after the disruption experienced during the state's transition to competition. We raised Maryland to "Less Credit-Supportive" from "Least Credit-Supportive" for the same reason and what we see as an increased use of credit-friendly rate mechanisms such as decoupling and other adjustment clauses.

Regulatory Jurisdictions For Utilities Among U.S. States

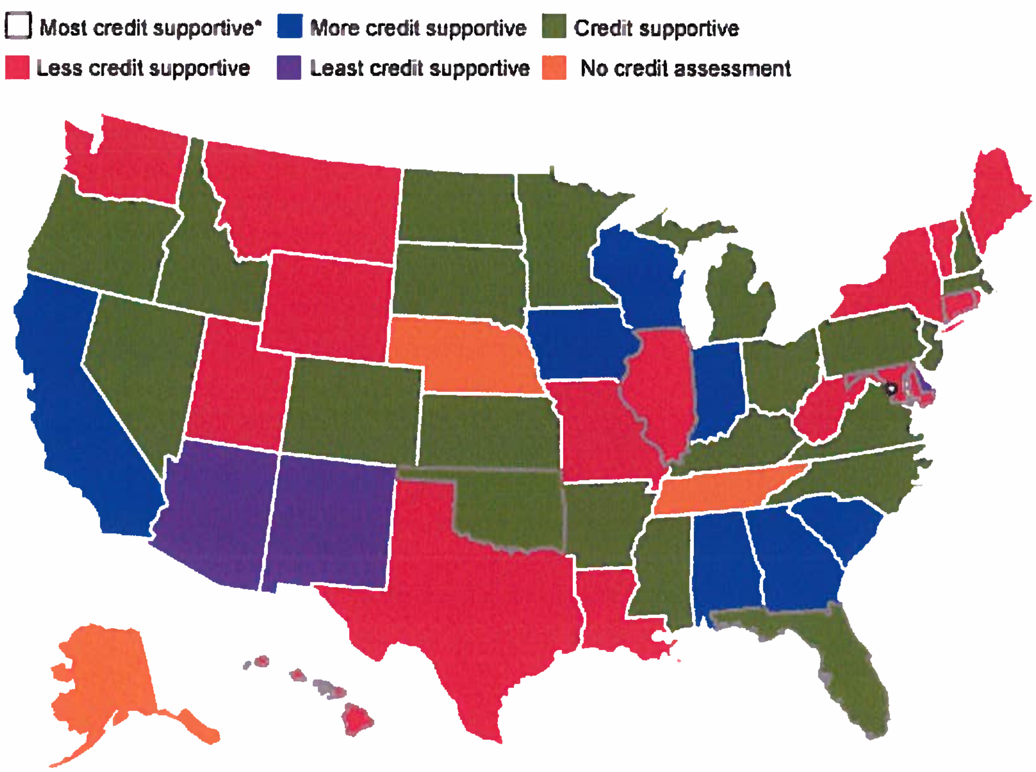
Most credit supportive	More credit supportive	Credit supportive	Less credit supportive	Least credit supportive
	Alabama	Arkansas	Connecticut¶	Arizona
	California	Colorado	Hawaii¶	Delaware
	Georgia	Florida¶	Illinois*	Dist. of Columbia
	Indiana	Idaho	Louisiana	New Mexico
	Iowa	Kansas	Maine	
	South Carolina	Kentucky	Maryland*	
	Wisconsin	Massachusetts	Missouri	
		Michigan	Montana	
		Minnesota	New York	
		Mississippi	Rhode Island	
		Nevada	Texas	
		New Hampshire	Utah	
		New Jersey	Vermont	
		North Carolina	Washington	

Regulatory Jurisdictions For Utilities Among U.S. States (cont.)

	North Dakota	West Virginia
	Ohio	Wyoming
	Oklahoma*	
	Oregon	
	Pennsylvania	
	South Dakota	
	Virginia	

*Assessment raised. ¶Assessment lowered.

Utility Regulatory Conditions Across 50 U.S. States



*The assessments are made against an absolute standard of the degree of credit support. At this time, we observe no U.S. jurisdictions that qualify in the top category. States outlined in gray have changed their regulatory condition since last surveyed.

STANDARD & POOR'S

Global Credit Portal®
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December 21, 2011

Sector Review:

How Utilities Around The World Are Coping With Regional Economies

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Table Of Contents

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Sector Review:

How Utilities Around The World Are Coping With Regional Economies

Credit quality trends continued to be somewhat mixed for the rated global utility universe in 2011. Notwithstanding lower or even stagnating economic growth everywhere, utility creditworthiness has been generally stable in several regions, specifically the U.S., Canada, Australia/New Zealand, and in most of Latin America and Asia. However, in Europe and Japan, credit quality momentum remains negative. In Europe, this is attributable to turbulent financial markets and weak economic conditions and the consequent pressures on profitability for many of the competitively exposed vertically integrated power incumbents. In Japan, particularly post-Fukushima, a stalled energy strategy, increasing costs, a sluggish economy, and the downgrade of Japan's sovereign rating continue to pressure credit quality. Across the globe, creditworthiness for entities operating under a predominantly regulated structure remains largely stable, while for those operating under a competitively exposed framework, the challenges have intensified. Common to both though is the need to reinvest heavily in infrastructure, replace assets, and modernize, which could weigh heavily on financial risk profiles if not conservatively financed.

We also see heightened political and environmental risks for the power industry due to global efforts to reduce carbon and other air emissions. This has, in our view, compounded the more traditional industry exposures to regulatory risks and significant ongoing reinvestment needs. However, Standard & Poor's Ratings Services continues to believe that regulated utilities will be able to recover through rates the ultimate cost of any mandated environmental compliance standards. However, our view could change if developments impel greater compliance spending severe enough to affect the willingness of regulatory bodies to pass on those costs to ratepayers. Meanwhile, many pressured integrated utilities are responding to these challenges by reducing discretionary growth-related investments, increasing cost-containment efforts, completing asset disposals, and proactively prefinancing upcoming maturities. Consequently, a very important dynamic shaping the overall financial condition of the industry will be management decisions and strategies, financial policies, and regulatory decisions.

U.S. Electric Utilities Maintain Stability Despite Slow Economic Recovery

As 2011 draws to a close, about three-quarters of U.S. investor-owned regulated electric companies have stable ratings outlooks and the predominance of ratings remain firmly entrenched in the 'BBB' category, despite a prolonged weak economic recovery. We expect ratings stability to continue based on expectations of responsive regulatory attention to cost recovery for needed capital investments and continued appetite by investors for utility debt and equity offerings.

Standard & Poor's base case outlook for the economy and for the electric utility industry for the remainder of 2011 and 2012 is stable, based on the following:

- Weak economic fundamentals in the U.S., characterized by modest GDP growth, sustained high unemployment levels, a still-weak housing market, and moderate increases in consumer spending;
- Modest growth in electricity consumption, despite the slow economic recovery;
- Generally constructive regulatory decisions; and
- Continued solid capital market access.

Regulated electric utilities have continued to weather the challenging economy of the past few years with little lasting effect on the industry's collective financial risk profile. The essential service that these companies provide and the rate-regulated nature of the business allow them to generate reasonably steady cash flows and to recover the bulk of their costs from ratepayers, despite economic conditions. Nevertheless, in times of exceptional economic hardship, regulators may be very reluctant to approve significantly higher electric base rates for consumers. As a result, we've seen many state commissions approve alternative ratemaking techniques to traditional base rate case applications and large rate increases, which help utilities sustain cash flow measures, earnings power, and, ultimately, credit quality. Hence, we believe that our ratings and outlooks, which we assess based on our view of industry- and company-specific factors, are unlikely to change even if economic conditions worsen in the near term. However, if 2012 produces accelerating economic growth, there could be some very modest improvement in creditworthiness, although probably not enough to revise ratings generally. Stronger employment would help reduce uncollectible accounts, increases in housing starts and the number of households would increase electricity consumption, and regulatory risk could possibly lessen as concerns about the plight of ratepayers abate and rising equity capital costs boost rate increases.

Creditworthiness in the U.S. electric utility industry has continued a long shift to greater stability. The number of ratings changes has continued to moderate, and upside rating actions have exceeded downgrades in 2011, a departure from the somewhat negative trend in 2010. Since Jan. 1, 2011, Standard & Poor's raised the corporate credit ratings of 27 holding companies and subsidiaries and lowered the rating on ten entities, six of which related to PPL Corp. (BBB/Watch Neg/--). The principal drivers of the upside rating activity were:

- Constructive ratemaking mechanisms and rate orders,
- Decreasing regulatory risk,
- Managements' commitment to credit quality and a focus on a straightforward regulated utility business model, and
- Improving financial conditions as a result of deleveraging, common stock issuance, and stronger cash flow.

Notable rating upgrades included those on CenterPoint Energy Inc., Northeast Utilities, and Pinnacle West Capital Corp.

The rating trend for U.S. electric utilities, as measured by outlooks and CreditWatch listings, is slightly positive, with nearly 15% of companies having positive outlooks or positive CreditWatch listings. Nevertheless, the trend is still largely biased toward stable, as about 77% of all U.S. investor-owned electric utilities carried a stable outlook at the end of November 2011. We see virtually no alteration in U.S. regulated electric utilities business risk and financial risk profiles during periods of economic change. As a result, we expect the number of prospective rating changes in the sector to remain moderate in the near-to-intermediate term.

The universe of U.S. electric utilities is relatively highly rated, certainly compared with the average 'BB+' category for U.S. industrial companies. This is a function of the large percentage of firms with excellent or strong business risk profiles, which, however, is generally balanced with aggressive financial risk profiles. As a consequence, almost 70% of the industry carries a 'BBB' category corporate credit rating ('BBB+', 'BBB', and 'BBB-'), about 26% 'A-' and above, and just 4% speculative grade ('BB+' and below).

The U.S. electric utility sector performed well through November 2011, with ongoing favorable access to capital markets compared with most corporate issuers. Reliance on external financing for electric utilities declined in the past 12 months, with the amount of medium- to long-term debt issued during the first 11 months of this year decreasing to about $25 billion from about $34 billion issued during the same period in 2010. We can attribute this to the significant amount of refinancing completed in the prior 12-month period, companies taking advantage of low interest rates with the prefinancing of debt well in advance of maturities and extension of maturities, the winding down of certain construction and environmental compliance programs, and the paring and deferral of discretionary and growth-related construction projects in response to weak economic conditions.

Investor appetite for electric first mortgage bonds remains healthy, with deals continuing to be oversubscribed. Credit fundamentals indicate that most, if not all, electric utilities should continue to have ample access to funding sources and credit. Issuance of common stock to partially fund construction spending is also possible for some firms, and would help to support the capital structure balance. Liquidity is an industry strength and has been improving, and banking syndicates are indicating a willingness to lengthen the terms of credit facilities out as far as five years, in some cases.

To maintain their current creditworthiness in this soft economy, electric utilities will need to have established, and be able to maintain, a firm credit foundation. This will require strong, collaborative, and effective working relationships among management, regulators and, increasingly, legislators and governors, in the planning and execution of strategies. Hence, looking to 2012, the political and regulatory landscape at the state and federal levels will continue to exert the most influence on electric utility credit ratings. Cost increases, construction projects, environmental compliance initiatives, and other public policy directives, together with lackluster electric load growth, will necessitate continued reliance on rate relief by electric utilities. Modest economic growth, better consumer and business confidence, and an improving job market should result in more credit-supportive regulatory outcomes. If the economy contracts, if employment levels weaken, and if consumer sentiment declines, regulatory support by state commissions will become more tenuous. Insufficient responses by utilities to counteract a reduction in regulatory support may drag on the industry, especially if utilities come under cost scrutiny by regulators, which is virtually inevitable, and could lead us to a negative stance on overall U.S. electric utilities' credit quality.

The Environmental Protection Agency has finalized its Cross-State Air Pollution Rule (CSAPR), which requires 27 states to reduce sulfur dioxide and nitrogen oxides emissions beginning in 2012 and again in 2014, and creates four emissions allowance trading programs. The CSAPR is not likely to lead to a shift in credit quality for the regulated electric utility industry. We have incorporated into current ratings the belief that costs associated with mandated environmental compliance standards would be recovered through state regulatory proceedings. However, our view could change if compliance spending becomes onerous enough to affect the willingness of state regulatory bodies to pass those costs on to ratepayers.

With regard to merger and acquisitions, we lowered the corporate credit ratings on DPL Inc. (BBB-/Stable/--) and subsidiary Dayton Power & Light Co. (BBB-/Stable/--) by three notches following the late November acquisition by lower rated AES Corp. (BB-/Stable/--). We also lowered the senior unsecured debt at DPL to 'BB+' from 'BBB+', the preferred stock to 'BB' from 'BBB', and the senior secured debt at DP&L to 'BBB+' from 'A'. The lower ratings are attributable to the substantial amount of acquisition-related debt incurred at DPL. Moreover, we believe that the combination with an entity that has significantly weaker business risk and financial risk profiles, as well as the ample leverage employed, demonstrates a lack of commitment to credit quality by DPL's management.

Several merger and acquisition transactions are pending various approvals. These combinations include:

- Exelon Corp. (BBB/Stable/A-2) and Constellation Energy Group Inc. (BBB-/Watch Pos/A-3),
- Northeast Utilities (BBB+/Watch Pos/--) and NSTAR (A+/Watch Neg/A-1), Duke Energy Corp. (A-/Stable/A-2) and Progress Energy Inc. (BBB+/Watch Pos/A-2), and
- Gaz Metro Limited Partnership's (A-/Stable/--) and Central Vermont Public Service Corp. (not rated).

Creditworthiness appears to be a factor in the recent flurry of mergers rather than an exclusive focus on shareholder value. Managements are more accepting of lower synergies and cost-saving assumptions, and acquisition premiums have declined. While the deals have not always been beneficial for all bondholders, the new merger model will produce larger, financially healthier and lower-risk regional utilities that are better able to manage regulatory risk, undertake large construction programs, and expand with minimal additional risk. While we continue to judge the credit implications of a merger transaction in the context of ongoing business strategies and financing plans, from our perspective a more efficient industry, with more concentration on relatively low-risk regulated operations could lead to improving creditworthiness for the sector.

Slow Economy Not Expected To Affect Canadian Utilities' Creditworthiness

Canadian utilities companies have been active in acquisitions and project developments recently, and this has affected credit quality for some of them. Despite weak market conditions, evolving environmental regulations, and increased scrutiny by provincial regulators in rate decisions, Standard & Poor's doesn't expect overall credit quality to weaken in the near-to-medium term. Exceptions could include companies that add substantive assets with higher cash flow variability or adopt more aggressive financial leverage policies to support growth aspirations. We maintain our view that higher-than-average regulated asset growth and utility financing and refinancing risk are manageable as utilities continue to enjoy good access to capital markets. Rate decisions from provincial regulators have remained generally supportive to the regulated utilities and pipelines including recognition of cash flow strain during large capital spending build-out in revenue determinations. We have observed increased scrutiny by the Ontario Energy Board in rate applications and requirement of the province's local distribution companies to justify cost increases and capital spending in recent rate decisions, as increasing ratepayer costs are emerging as an important concern. So far, this has not resulted in any material disallowances, and we continue to believe regulators will maintain the balance between ensuring prudency of spending and allowing justified returns for regulated utilities.

There have been few changes in environmental-related regulations, although we expect the federal government to become more proactive in setting standards and regulations. The federal government has announced plans to close coal plants in existence before July 1, 2015, that reach 45 years of age or whose power purchase agreement expires, whichever is later unless they incorporate carbon-capture-and-storage or other feasible technologies to reduce greenhouse gas emissions to levels similar to that of a natural gas plant. They also plan to prohibit construction of new coal-fired power plants after July 1, 2015 unless they are able to control their emissions to levels typical of natural-gas plants.

If implemented, these requirements could, in our view, have two different medium-term effects on incumbent generators, particularly in Alberta, where coal-fueled plants make up more of the province's total generation capacity than it does elsewhere. On one hand, operators of aging coal-fired plants could have to close plants reaching the age limits and therefore face reduced generation volume, possible asset write-offs, and higher asset-retirement costs. On the other hand, this could reduce electricity generation capacity and supply and push electricity prices up, unless new facilities take their place quickly. The higher electricity prices could in turn benefit incumbent operators who operate noncoal or newer coal facilities. We will assess the asset mix of each rated generation company and its strategy in response to these requirements as they develop and changes in environmental regulations to determine the impacts, if any, to credit. Ontario is nearing the end of a 10-year period (2004-2014) of phasing out its coal plants, all of which are government-owned. Its coal capacity is gradually being replaced with refurbished nuclear plants and new gas-fired and renewable facilities, as well as conservation efforts.

Canadian economic growth stalled in second-quarter 2011, mostly due to worsening exports for Canadian companies. Although exporting recovered in the third quarter and GDP growth turned positive again, Standard & Poor's expects deteriorating global growth, lower commodity prices and the strong Canadian dollar to continue weighing on the country's economic performance. Slower momentum in domestic spending could also undercut GDP growth as businesses conserve capital and rethink their spending plans, awaiting greater certainty around the economic outlook. With these assumptions, we think it will take longer for excess slack in the economy to disappear, so Canadian workers could be facing a period of diminishing job opportunities. As such, we're assuming Canada's unemployment rate (7.4%) could increase again (likely through mid-2012), after declining through most of 2010 and in the first half of 2011. Against this backdrop, slowing labor income growth could constrain consumer spending as households focus on paying down the increased debt burdens they've accumulated. So we think it will take longer for GDP growth to move back up to rates in the 3.2% area that are typical for Canada's economy during expansionary periods. We've lowered our forecast for GDP growth to 2.3% in 2011 (versus our previous forecast of 2.8% for 2011), and in 2012 we now expect to see growth of 2.1% for Canada (compared with 3% previously). However, we think recessionary risks will remain relatively low for Canada so we do not expect subpar GDP growth to have any meaningful negative effect on regulated utilities in the next two years.

European Utilities' Profitability Is Challenged

Credit trends for the leading European utilities rated by Standard & Poor's remain largely negative overall. Of the top-25 European utilities, for example, 10 have negative outlooks or are on CreditWatch with negative implications. This reflects significant pressure on profitability for many of the competitively exposed vertically integrated power incumbents, an aging generation asset base with significant reinvestment needs, rising political risks, sovereign stress in the eurozone, and higher environmental costs. In addition, turmoil in the financial markets heightens financial risks and, in our view, Europe's economic outlook once again appears increasingly somber. We now expect a mild recession in first-half 2012 in the eurozone, ahead of a modest pick-up in the second part of the year. We anticipate eurozone real GDP growth to average 0.4% next year, which is likely to lead to a fall in energy demand in many European countries.

However, underlying credit quality for regulated utilities, electricity and gas networks in particular, remain relatively solid. Ratings for electricity and gas transmission system operators in the peripheral eurozone countries are largely at risk of being lowered, mainly due to sovereign-related stress.

We believe the larger European power and gas utilities will continue to focus extensively on efficiency enhancements and cost control to relieve some of the immediate pressure on profitability from challenging market conditions. In addition, reductions in capital spending and an acceleration of disposal programs are likely to lead utilities to make efforts to deleverage and to enhance financial flexibility. We are particularly concerned with any possible disruption of financial markets due to unforeseen exogenous shocks, as European utilities have significant amounts of debt falling due in the coming years. We believe utilities based in Greece, Italy, Ireland, Portugal, and Spain to be particularly exposed, as access to long-term funding could be increasingly challenging and will undoubtedly come at a higher cost.

Latin American Utilities Are Expanding Capacity And Infrastructure

Latin American electric utilities fared relatively well in the 2008 economic crisis, supported by its large and dynamic domestic market. This resilience might be tested again if the global economy enters another recession. Standard & Poor's has revised its growth prospects for Latin America, reducing expected real GDP growth to 4.2% in 2011 and 3.8% in 2012 (previous forecast of 4.5% and 4.2%, respectively). However, we expect electricity demand to continue growing above GDP. Consequently, companies are carrying out sizable capital expenditures to not only expand capacity (Colombia, Chile, and Brazil) and diversify energy generation sources (Brazil, Mexico, and Dominican Republic), but also to improve infrastructure (Brazil, Panamá, and Guatemala).

The local capital markets have been very active in Brazil, Chile, Mexico, Colombia, and Panamá, allowing companies to obtain funding mainly in local currency in line with their revenues, thus reducing currency mismatch risks. Also, the companies benefit from long-term and low-cost funding from national development banks and multilateral agents, such as Brazilian National Development Bank, International Finance Corp., and Inter-American Development Bank, especially for the financing of new generation and transmission assets.

Standard & Poor's views Latin American electric utilities as generally well positioned to continue supporting local economies' growth due to the sizable investments under way to improve infrastructure and expand energy supply capacity to serve new consumers in the local markets, especially as a result of social programs.

During 2011, we have raised some ratings of Brazilian electric utilities, reflecting our view of a stable regulatory framework and positive demand trends, combined with generally stronger cash generation and prudent liability management. Most of the upgrades resulted from improved financial risk profiles because the companies benefited from favorable credit market conditions to refinance existing debt with lower funding costs and longer tenors, reducing refinancing risks for the next few quarters.

In the first 11 months of 2011, we've rated debt issuances from Brazilian electric utilities of about Brazilian real (R$) 6.3 billion (about $3.7 billion), in both the local and international markets, with average tenors of six years. Some companies also increased cash position for acquisition opportunities. During 2011, merger and acquisition activity has been quite active with announced transactions of around R$7 billion, from Companhia Energetica de Minas Gerais S.A. (Cemig); CPFL Energia S.A., and Spanish group Iberdrola S.A., with no impact on the existing ratings.

Uncertainties regarding the third tariff revision cycle for distribution companies in Brazil have reduced, with a new methodology almost concluded. The current ratings already reflect our base case scenarios that assume a potential reduction of 20% to 25% in profitability of the rated companies after the tariff reset. Another important topic relates to the expiration of several generation and transmission concession contracts (nearly 20% of Brazil's installed capacity and 50% of transmission lines), from 2015 to 2017, that would revert to the government for new auctions. We believe this matter will be resolved soon, because it's critical for the functioning of the electric system in Brazil--otherwise generators and distributors will not be able to sign long-term energy contracts, which would probably pressure energy prices.

Our ratings on Argentinean electric utilities continue to reflect our view of high regulatory risk, and the continued deterioration in the companies' cash flow generation, as tariffs do not reflect the increases in operating costs. In addition, there is a significant discretion in the political decision-making process that makes it very difficult to forecast future repayment performance and genuine investment plans.

In Chile, companies should continue benefiting from economic growth prospects, boosting power demand. Despite weaker financial performance at some companies due to the prolonged drought in the central and southern regions, all the ratings on our rated utilities remain unchanged in 2011.

In Mexico, the Comision Federal De Eletricidad (CFE) is consolidating its critical role as the only provider of electricity in Mexico and the sole entity responsible for planning and operating Mexico's electric system. In mid-2011, CFE tapped the international market for the first time in over a decade with a US$1 billion issue as part of it diversification and growth strategy into alternative generation sources and national grid expansion.

In Colombia, we view Interconexión Eléctrica S.A., ISAGEN S.A., Empresa de Energía de Bogota S.A., and Transportadora de Gas Internacional as well positioned for a soaring period to come, enhanced by a developed and stable regulatory environment in the country. The successful diversification of the companies' core operations into several countries in the region, such as Brazil, Chile, Peru, and Panama, which now have investment-grade sovereign ratings, and the diversification of their businesses into nonenergy-related operations is consistent with becoming operating holding groups. We expect these companies to continue posting strong cash-flow metrics and maintain prudent debt-management policies as they consolidate their business strategies and geographical outreach.

Overall, we still expect that medium-term growth for the Latin America electric sector will continue getting support from the utilities' domestic markets to face global turbulence. Despite lower economic growth prospects, the region should keep positive market dynamics. We also believe that improved access to financing in local capital markets as well as in local and foreign bank markets will generally enhance financial flexibility for the next few years.

Australian Utilities Face Regulatory Challenges

In Australia, legislation introducing the federal government's carbon abatement scheme passed, and will be introduced on July 1, 2012. The scheme could complicate the re-financing of a number of coal-fired generators with debt that falls due about the time or shortly after the scheme begins. In other Australian regulatory developments, a series of proposed rule changes and multiple reviews of the energy sector are the next tests for Australian utilities' credit quality. How the rated entities respond to these evolving changes will be critical in determining the ultimate impact on the sector's credit quality, given that the regulatory framework is an important component of the regulated utilities' businesses. Most rated utilities are on a stable footing, with only three companies on negative rating outlooks as of Nov. 21, 2011.

In New Zealand, the re-election of the National Party government last November is expected to result in the sale of the three state-owned integrated generator-retailers. While the timing is yet to be determined, it is expected that this process will begin sometime in 2012.

Asian Utilities' Credit Quality Should Retain Stability

The credit quality of electric utilities that Standard & Poor's rates in Asia is likely to remain broadly stable in the next 12 months. These companies benefit from favorable industry dynamics and demographic trends that point to increasing demand for utility services. Economic growth in the region is faster than the world average, and domestic populations are large with low electricity consumption and urbanization is increasing. Regulatory frameworks broadly support this sector, and in some markets, governments provide direct subsidies and other support.

Some of the notable rating actions this year include the multiple downgrades of Tokyo Electric Power Co. Inc. (TEPCO) to B+/Watch Dev/B, from AA-/Stable/A-1+ prior to the March 11 natural disaster, and the downgrade of several Japanese electric utilities to A+/Negative/A- from AA-/Negative/A-1+ to reflect the uncertain environment for electric utilities in Japan (see separate section on Japan below).

Economic growth across the region is being revised downwards as financial turbulence in advanced Western economies is spilling over into the region. Demand for electricity in the region, particularly from the industrial sector, is likely to slow down if the global economy enters another recession. In our view, the economic decline alone is unlikely to result in downgrades of utility companies. Since electricity demand is not particularly elastic, declines in usage may not be as large as the overall economic contraction. This is particularly true if a major portion of a utility's customer base is residential, where usage is less affected by economic cycles. The more pressing issue is the ability of utilities to adapt to the changing economic and financial environment. Some economies in the region, such as Singapore, Thailand, and the Philippines, rely heavily on export-driven income, and a global slowdown may affect economic growth. For countries such as India, China, and Indonesia that have sizable domestic economies, the impact of another global slowdown on their domestic utilities may not be that much.

Inflation across the region remains high, and has been inching up in most economies throughout the year. Inflation is being further exacerbated by rising fuel costs for electric power plants, contributed largely by the natural disasters in the region this year, including earthquakes in New Zealand, flooding in Australia and Southeast Asia, and the twin disasters in Japan. The approach of governments across the region to address rising fuel costs has been mixed across the region depending on:

- The tariff frameworks in their respective countries,
- The availability of fuel sources domestically, and
- The extent of government subsidies.

Governments and regulators are reluctant to raise tariffs to protect utilities even as fuel costs rise because such hikes could fuel inflation. Without government subsidies or support, delays in tariff increases affect utilities' profitability and cash flows.

Competition for fuel is on the rise following the natural disasters, as well as market-specific factors such as the coal shortage in large, power-hungry economies like India's. To secure fuel, Japanese firms are investing heavily in several liquefied natural gas terminal projects in Australia, while some of the Southeast Asian nations are stepping up oil and gas exploration in the region. Coal shortages in India, which has the third-largest coal reserves in the region where the top three dominate by a wide margin, is also driving up coal costs. Coal India Ltd. (not rated), the country's leading state-owned producer, has not been able to mine coal at a rate that could keep pace with demand. This has led to Indian electricity companies getting coal from coal-rich countries such as Indonesia and Australia.

Vertical integration through acquisition of stakes in operations of companies that produce primary fuel has helped some companies address fuel security. For example, Indian utilities, such as Tata Power Co. Ltd. (BB-/Positive/--), have been acquiring coal mines in Indonesia and Australia, while many Chinese power companies have ventured into upstream coal mine acquisitions to hedge fuel cost risk. Sizable investments may at times pressure the gearing of companies, especially if gearing is already high.

Although the ratings of our rated electric utilities in the region are broadly stable, we are focusing heavily on three key markets over the next 12 months. The first is Japan, where problems at the Fukushima nuclear plant following the March 11 earthquake and tsunami have made the country's energy policy uncertain. We are watching closely actions by the Japanese government for compensation plans to be introduced for TEPCO and more broadly its effect on other Japanese electric utilities. The second market is Korea, where we think the stand-alone credit profile of Korean electric utilities will continue to be pressured due to the industry's inability to pass on higher fuel costs for electricity to consumers due to an inefficient tariff structure, and reluctance by the government to increase tariffs due to high inflation levels in the country. The third market is China, where the aggressive expansionary plans and desire to secure fuel sources of Chinese electric utilities may pressure balance sheets and credit metrics.

More generally in the region, we are monitoring how electric utilities manage their refinancing and liquidity needs, plus their headroom against financial policies and debt covenants. We also continue to pay close attention to shareholder behavior and support, as well as integration and construction risks associated with large capital investments and merger and acquisition activity, both of which we expect to increase across the region.

Japanese Utilities Are Still Dealing With March 2011 Disaster

Post-Fukushima, a stalled energy strategy and increasing costs continue to put downward pressure on the Japanese utility sector. Standard & Poor's continued to revise downward credit trends for the utilities through this year, mainly due to:

- Downward revision of Japan's sovereign rating and sluggish domestic economy,
- Significantly increasing costs to replace nuclear power and the capital spending burden to strengthen safety measures following TEPCO's Fukushima No.1 nuclear plant disaster, and
- Increasing uncertainty about government energy policy.

The outlook on all seven of the rated Japanese utility companies is negative. The ongoing Fukushima nuclear disaster has pushed Japan's energy policy to a crossroads. With public sentiment shifting away from nuclear energy, which had been at the forefront of Japan's energy plan for the next decade and given problems with the alternatives, it is difficult to tell what direction a restructured national energy strategy will take. A sharp rise in fuel costs for thermal power and ongoing political uncertainty further complicate how best to provide this essential service.

Until the government's commitment to support TEPCO is confirmed and the government finalizes its new energy policy, the downward trend for the sector should last in our views. Although the central government, in November 2011, approved financial aid to TEPCO, the plan to restructure the company remains unclear. The government's review and approval of the plan is expected to come around next March. We think prolonged uncertainty over the utility sector may lead to higher long-term funding costs in the future.

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Top 10 Investor Questions About U.S. Gas And Water Utilities In 2012

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Table Of Contents

Top 10 Investor Questions About U.S. Gas And Water Utilities In 2012

Near-term credit quality for U.S. natural gas local distribution companies should be generally stable in 2012. Standard & Poor's Ratings Services' key assumptions behind this forecast are supportive regulatory decisions, continued access to capital markets, and reduced working capital requirements related to natural gas prices. Nevertheless, an increasing contribution to consolidated cash flows from nonregulated businesses is putting some pressure on credit quality.

Investor-owned water utilities make up one of the most stable and highly rated sectors in our rated universe of U.S. corporate issuers. For 2012, we expect our ratings on water utilities also to remain stable as the cash flows from approved rate cases trickle in. Key near-term trends include ongoing improvement in the quality of regulatory mechanisms to address increased capital spending and the continuing need to tap capital markets.

Despite all the stability in the sectors, we do get topical questions from investors, and we answer the top 10 inquiries below.

Credit Concerns

How is the weak economy affecting gas and water utilities' credit quality?

The essential nature of the services that both sectors provide and the rate-regulated nature of the businesses enable them to generate stable cash flows and recover their costs, even when the general economy is weak. Moreover, regulatory commissions are increasingly implementing rate mechanisms, such as cost tracking and decoupling structures, that tend to insulate utilities from economic trends, thereby making the economy even less of a factor for credit quality. Natural gas consumption, both residential and commercial, is generally stable depending on the severity of winter weather, and minimal customer conservation somewhat offsets incremental usage variations.

We expect water consumption, which is generally aligned with population and household growth, to increase minimally in 2012. We also expect housing starts to be up about 10% (to about 670,000) this year from last year, which will help slowly increase customer consumption.

Effect on gas and water credit quality. We see little change in regulated gas and water utilities' credit risk profiles during periods of economic weakness. Only a severe and prolonged recession, in our view, could prompt regulators to defer, or even disallow, reasonable costs that utilities incur and to significantly lower allowed returns on equity (ROE). Consequently, we are not currently expecting to take any rating actions this year.

How are low natural gas prices affecting gas utilities?

Gas utilities usually generate stable cash flows, regardless of natural gas prices, and price changes have little bearing on credit quality. All rated gas utilities benefit from gas-adjustment mechanisms that allow them to pass the cost of gas directly to consumers. Utilities generate their core earnings and cash flows from delivering the gas. On the profit margin, though, lower natural gas prices, like the roughly $2.50 per million cubic feet (mmcf) currently, help credit quality by providing greater opportunities for gas heating conversions as expenses related to conversion to gas become worthwhile for the customers. Working capital needs are also lower as utilities spend less to store gas for peak requirements, which enhances financial flexibility. Low gas prices can also ease regulatory resistance to rate increases related to basic infrastructure needs.

Effect on gas credit quality. Here again, we do not expect to take any rating changes on regulated gas utilities under the current gas prices.

What are the most noteworthy regulatory developments affecting gas and water companies?

Recent regulatory developments have been positive for credit quality. In the water industry, for instance, New Jersey in early 2012 became the fifth state to approve the implementation of a distribution system investment charge (DSIC) mechanism. The DSIC program allows for rate increases for nonrevenue-producing investments to be used to replace aging infrastructure without going through general rate proceedings. In addition, regulatory commissions overseeing both the gas and water sectors continue to implement mechanisms to smooth cash flows, the most important of which are rate "decoupling" and straight-fixed-variable-rate designs, which help make cash flows more stable and predictable.

Effect on gas and water credit quality. State regulation will remain an influential factor in gas and water utility credit ratings. Although average ROEs have declined slightly in the past few years, several jurisdictions have granted enhanced rate-making mechanisms that help ensure greater cash flow stability.

Have capital expenditures been up or down lately?

Some of the larger gas utilities increased their capital spending significantly in 2011. Total industry capital spending increased more than 18% last year after growing about 4% in 2010 (see table 1). A primary cause of this increase was the focus on pipeline safety standards after multiple pipeline explosions, in particular the San Bruno, California, accident. We expect the replacement of aging pipelines and other infrastructure needs to continue in 2012, keeping capital spending levels high.

The large water utilities scaled back their capital spending about 8% in 2011 from 2010 levels. But we expect capital spending in the water sector to continue growing as utilities replace aging infrastructure and meet stringent water treatment and quality standards.

Table 1

Gas And Water Utilities' Funds From Operations And Capital Expenditures

(Mil. $)

	--FFO--				--Capital expenditures--			
	2011*	2010	2009	2008	2011*	2010	2009	2008
Gas								
Sempra Energy	2,294	2,441	2,111	1,601	2,885	2,204	1,854	2,044
NiSource Inc.	1,370	1,225	1,204	1,052	1,022	801	876	1,284
Atmos Energy Corp.	588	631	548	534	621	554	530	483
AGL Resources Inc.	643	535	524	457	487	510	469	372
Southern California Gas Co.	728	722	618	527	858	697	474	469
Piedmont Natural Gas Co. Inc.¶	279	243	267	240	266	199	132	186
Nicor Gas Co.	312	309	285	239	203	187	194	230
Washington Gas Light Co.	263	284	265	215	182	126	137	138
New Jersey Natural Gas Co.	114	150	124	106	101	93	74	71
Laclede Gas Co.	122	116	97	83	68	60	53	57
Vectren Corp.	488	498	423	423	308	278	426	391
Indiana Gas Co. Inc.	96	93	129	107	52	41	57	72

Table 1

Gas And Water Utilities' Funds From Operations And Capital Expenditures (cont.)

Total	**7,296**	**7,246**	**6,594**	**5,583**	**7,053**	**5,750**	**5,276**	**5,797**
Capital expenditures year-over-year change (%)					22.7	9.0	(9.0)	
Water								
Aqua America Inc.	356	325	275	244	311	326	285	264
California Water Services Group Inc.	103	91	94	89	114	124	110	105
SJW Corp.	62	50	53	53	75	100	57	69
American States Water Co.	129	122	94	68	88	82	81	84
Connecticut Water Service Inc.	26	22	21	19	24	27	28	20
Middlesex Water Co.	27	26	23	23	25	29	20	28
Total	**702**	**636**	**560**	**496**	**636**	**687**	**581**	**569**
Capital expenditures year-over-year change (%)					(7.4)	18.3	2.0	

*Twelve months ended Sept. 30. ¶Figures for 2011 are as of October. Source: Company reports.

Effect on gas and water credit quality. We do not expect to take any rating actions on regulated gas and water utilities if they can recover funds associated with capital spending through a regulatory process in a timely manner and if their credit measures do not deteriorate.

What trends are you seeing in gas and water utilities' nonregulated businesses?

Most regulated gas utilities are slowly increasing their cash flows from nonregulated operations. Traditionally, nonregulated segments have comprised wholesale and retail marketing operations, which have rapidly declining cash flows because of abundant low-priced natural gas, leading to a collapse in basis spreads. We see increasing investments in renewable energy forms, particularly solar energy, as companies reap benefits from various forms of regulatory and tax support. Some utilities are also investing in various shale plays, where they typically generate some royalty revenue from mineral rights.

Effect on gas and water credit quality. In general, we do not consider cash flows from nonregulated segments to be as stable and predictable as those from regulated distribution operations. As such, we expect nonregulated operations to pressure credit quality as they grow, particularly if financial performance does not strengthen. For instance, last year we lowered the rating on WGL Holdings Inc. to 'A+' from 'AA-' because its nonregulated businesses, specifically its retail energy marketing and energy systems businesses, increased to more than 10% of consolidated cash flow.

How does Standard & Poor's expect refinancing risk to affect the gas and water utility sectors?

Minimally. Only two gas companies (Southwest Gas Corp. and Southern California Gas Co.) have debt maturities in 2012 that account for at least 15% of their total debt outstanding (see table 2). We expect both issuers to refinance these obligations with new debt, cash, or balances under their revolving credit facilities.

Table 2

Gas Local Distribution Company Debt Maturities In 2012

Maturity date	Issuer	Ultimate parent	Fixed-income security type	Seniority level	Coupon rate (%)	Coupon type	Offering amount (mil. $, historical rate)	Amount outstanding (mil. $, historical rate)
Feb. 27, 2012	Washington Gas Light Co.	WGL Holdings Inc.	Corporate MTN	Senior unsecured	6.0	Fixed	25.0	25.0

Table 2

Gas Local Distribution Company Debt Maturities In 2012 (cont.)

March 26, 2012	Northwest Natural Gas Co.	Northwest Natural Gas Co.	Corporate MTN	Senior secured	7.13	Fixed	40.0	40.0
May 1, 2012	Michigan Consolidated Gas Co.	DTE Energy Co.	Corporate MTN	Senior secured	7.06	Fixed	40.0	40.0
May 15, 2012	Southwest Gas Corp.	Southwest Gas Corp.	Corporate debentures	Senior unsecured	7.625	Fixed	200.0	200.0
June 5, 2012	Atlanta Gas Light Co.	AGL Resources Inc.	Corporate MTN	Senior unsecured	8.4	Fixed	5.0	5.0
June 19, 2012	Washington Gas Light Co.	WGL Holdings Inc.	Corporate MTN	Senior unsecured	5.9	Fixed	25.0	25.0
June 19, 2012	Atlanta Gas Light Co.	AGL Resources Inc.	Corporate MTN	Senior unsecured	8.3	Fixed	5.0	5.0
July 1, 2012	Atlanta Gas Light Co.	AGL Resources Inc.	Corporate MTN	Senior unsecured	8.3	Fixed	5.0	5.0
July 23, 2012	SEMCO Energy Inc.	Continental Energy Systems LLC	Revolving credit	Senior secured	--	--	130.0	130.0
July 30, 2012	Energen Corp.	Energen Corp.	Corporate MTN	Senior unsecured	7.21	Fixed	1.0	1.0
Aug. 6, 2012	Questar Gas Co.	Questar Corp.	Corporate MTN	Senior unsecured	6.91	Fixed	20.0	20.0
Aug. 06, 2012	Questar Gas Co.	Questar Corp.	Corporate MTN	Senior unsecured	6.9	Fixed	5.0	5.0
Sept. 4, 2012	Cascade Natural Gas Corp.	MDU Resources Group Inc.	Corporate MTN	Senior unsecured	8.06	Fixed	14.0	14.0
Oct. 1, 2012	Questar Gas Co.	Questar Corp.	Corporate MTN	Senior unsecured	6.89	Fixed	3.0	3.0
Oct. 1, 2012	Questar Gas Co.	Questar Corp.	Corporate MTN	Senior unsecured	6.85	Fixed	35.0	35.0
Oct. 1, 2012	Southern California Gas Co.	Sempra Energy	Corporate debentures	Senior unsecured	4.8	Fixed	250.0	9.26
Oct. 1, 2012	Questar Gas Co.	Questar Corp.	Corporate MTN	Senior unsecured	6.3	Fixed	60.0	60.0
Oct. 1, 2012	Southern California Gas Co.	Sempra Energy	Corporate debentures	Senior secured	4.8	Fixed	250.0	250.0
Oct. 8, 2012	Cascade Natural Gas Corp.	MDU Resources Group Inc.	Corporate MTN	Senior unsecured	8.11	Fixed	3.0	3.0
Oct. 8, 2012	Cascade Natural Gas Corp.	MDU Resources Group Inc.	Corporate MTN	Senior unsecured	8.1	Fixed	5.0	5.0
Oct. 15, 2012	Laclede Gas Co.	Laclede Group Inc.	Corporate debentures	Senior secured	6.5	Fixed	25.0	25.0
Oct. 15, 2012	Laclede Gas Co.	Laclede Group Inc.	Corporate debentures	Senior unsecured	6.5	Fixed	6.49	18.51
Oct. 31, 2012	Northern Natural Gas Co.	MidAmerican Energy Holdings Co.	Corporate debentures	Senior unsecured	5.375	Fixed	300.0	300.0
Nov. 15, 2012	EQT Corp.	EQT Corp.	Corporate debentures	Senior unsecured	5.15	Fixed	200.0	200.0

Table 2

Gas Local Distribution Company Debt Maturities In 2012 (cont.)

Nov. 15, 2012	EQT Corp.	EQT Corp.	Corporate debentures	Senior unsecured	5.15	Fixed	200.0	200.0

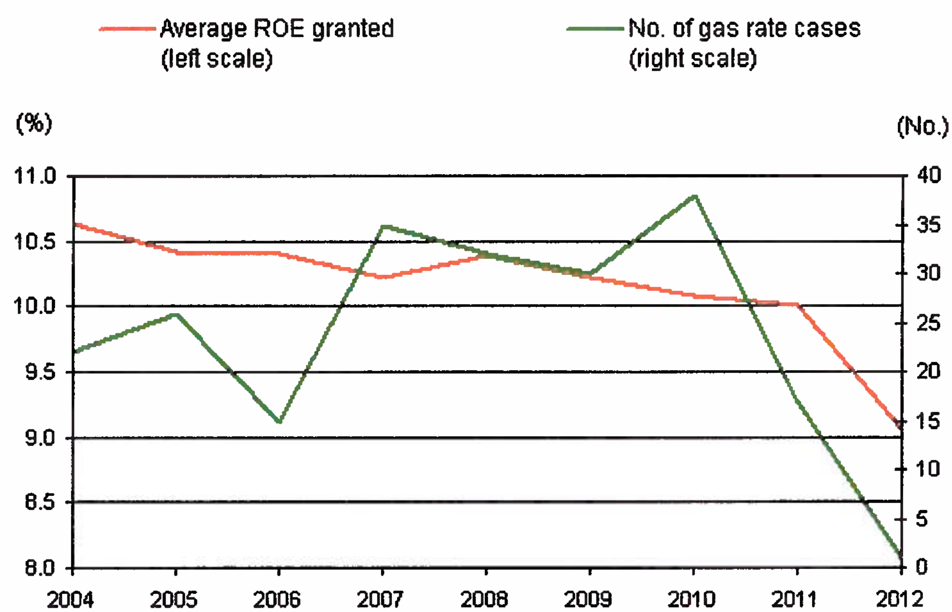
MTN--Medium-term note. Source: Capital IQ.

Effect on gas and water credit quality. Refinancing risk should not be an issue this year because of utilities' continuing solid access to capital markets, even if the general economy is weak.

How have allowed ROE measures been?

ROE levels that state commissions authorize to gas utilities have been steadily eroding over the past decade, dropping to below 10% in 2011 from about 10.6% in 2004 (see chart). We believe the primary reasons for this are prolonged weak economic activity and low interest rates, reduced working capital requirements in line with low gas prices, and the implementation of enhanced cost-recovery mechanisms. From a regulator's point of view, these factors lower a utility's risk profile.

Returns On Equity Granted To Natural Gas Local Distribution Companies



Source: SNL Financial LC.

Effect on gas and water credit quality. From a credit-quality perspective, the decline in authorized ROEs has generally been offset by greater cash flow certainty, so the change in credit quality has been neutral.

How do you think pipeline safety standards will affect the industry?

Gas pipeline safety issues have focused significant national attention on operational failures and the age and the increasingly apparent fragility of some of the nation's natural gas transportation infrastructure ever since the San Bruno, Calif., gas main blast in 2010. We expect greater regulatory and company oversight of operating and safety measures, with the most immediate effects being increases in reporting requirements and spending on maintenance. Cost recovery will likely occur via the regulatory process. For example, Southern California Gas plans to spend nearly $3 billion during the next 10 years to comply with new requirements to test or replace all transmission pipelines that have not been pressure-tested.

Effect on credit quality. We do not currently envision any new regulations that would meaningfully affect credit quality across the sector. A company's financial profile could be at risk if capital expenditures go up sharply to rectify problems, and the company cannot quickly recover those costs.

What is causing asset swaps in the water sector?

We believe the ability to manage regulatory relationships is the primary cause of these swaps because companies are keen to recover their expenses through rate case returns, especially in a weak economy. Through acquisitions, companies also seek to build economies of scale by serving contiguous customers. Most of the acquisitions and divestitures have been between Aqua America Inc. and American Water Works Co. Inc. Aqua sold its New York operations to American while purchasing American's Ohio operations. Previously, Aqua sold its Maine operations to Connecticut Water Service Inc., and American sold its New Mexico and Arizona assets to EPCOR Utilities Inc. It is worth noting that both Aqua and American have reported lower operating costs per customer served for the past several quarters. From a regulator's point of view, these factors lower a utility's risk profile.

Effect on gas and water credit quality. Generally, we consider prudent asset swaps beneficial to credit quality if they improve returns, increase quality of service, or lower operating costs.

What is behind some negative outlook actions in the water sector?

We expect credit measures to be weaker in 2012 than they were last year because of the additional debt on utilities' balance sheets. We revised the outlook on Connecticut Water to negative from stable in October 2011 following its announcement of the debt-financed acquisition of Aqua Maine Inc. The utility issued $24 million in incremental debt in the fourth quarter and $36.5 million to finance the acquisition, including the assumption of $17 million in debt. We also revised the outlook on California Water Service Co. to negative from stable in December 2011 because we expect its credit measures to remain weak for the rating for the next few quarters. Despite an excellent business risk profile and an 'A+' rating, the company is facing capital expenditures for infrastructure replacement, compliance with water quality standards, and limited control of future water supply.

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Global Credit Portal®
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June 21, 2012

Issuer Ranking:

Canadian Utilities And Pipelines, Strongest To Weakest

Primary Credit Analyst:
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Issuer Ranking:

Canadian Utilities And Pipelines, Strongest To Weakest

The following list ranks all the rated companies in this industry from strongest to weakest based on rating and outlook. Companies with the same rating and outlook are further ranked by our opinion of credit quality based primarily on business risks for investment-grade companies and primarily on financial risks for speculative-grade companies.

Ratings are displayed as long-term rating/outlook or CreditWatch/short-term rating. A double dash (--) indicates no rating. Issuer credit ratings are identical for local and foreign currency unless noted with the "LC" and "FC" designations.

For the related industry report card, please see "Growth Poses Biggest Challenge To An Otherwise Stable Canadian Midstream And Utility Sector," published Feb. 15, 2012, on RatingsDirect on the Global Credit Portal.

Issuer Ranking: Canadian Utilities*

Electric utilities and generation

Issuers	Corporate credit rating*	Business risk	Financial risk
Hydro One Inc.§	A+/Negative/A-1	Excellent	Significant
Canadian Utilities Ltd.	A/Stable/A-1	Excellent	Significant
CU Inc.	A/Stable/A-1	Excellent	Significant
ATCO Ltd.	A/Stable/--	Excellent	Significant
Hydro Ottawa Holding Inc.§	A/Stable/--	Excellent	Intermediate
Toronto Hydro Corp.§	A/Stable/--	Excellent	Significant
London Hydro Inc.§	A/Stable/--	Excellent	Intermediate
Enersource Corp.§	A/Stable/--	Excellent	Significant
Guelph Hydro Electric Systems Inc.§	A/Stable/--	Excellent	Significant
Horizon Holdings Inc.§	A/Stable/--	Excellent	Intermediate
Hamilton Utilities Corp.§	A/Stable/--	Excellent	Intermediate
Electricity Distributors Finance Corp.†	A	Excellent	Significant
PowerStream Inc.	A/Stable/--	Excellent	Significant
UMH Energy Partnership†	A		
ENTEGRUS Inc.§‡	A/Negative/--	Excellent	Intermediate
AltaLink L.P.	A-/Stable/--	Excellent	Significant
FortisAlberta Inc.	A-/Stable/--	Excellent	Significant
Fortis Inc.	A-/Stable/--	Excellent	Significant
Caribbean Utilities Co. Ltd.	A-/Stable/--	Excellent	Significant
Ontario Power Generation Inc.§	A-/Stable/--	Strong	Significant
Brookfield Infrastructure Partners L.P.	BBB+/Stable/--	Strong	Significant
EPCOR Utilities Inc.	BBB+/Stable/--	Strong	Significant
ENMAX Corp.§	BBB+/Stable/--	Strong	Significant
Maritime Electric Co. Ltd.	BBB+/Stable/--	Strong	Significant

Issuer Ranking: Canadian Utilities* (cont.)			
Nova Scotia Power Inc.	BBB+/Negative/--	Strong	Significant
Emera Inc.	BBB+/Negative/--	Strong	Significant
Brookfield Renewable Energy Partners L.P.	BBB/Stable/A-2	Satisfactory	Intermediate
Capital Power L.P.	BBB/Negative/--	Strong	Significant
Capital Power Corp.	BBB/Negative/--	Strong	Significant
TransAlta Corp.	BBB/Negative/--	Satisfactory	Intermediate
Northland Power Inc.	BBB-/Positive/--	Satisfactory	Intermediate
Algonquin Power Co.	BBB-/Positive/--	Satisfactory	Significant
AltaLink Investments L.P.	BBB-/Stable/--	Excellent	Aggressive
Innergex Renewable Energy Inc.	BBB-/Stable/--	Strong	Significant
Capstone Infrastructure Corp.	BB+/Stable/--	Satisfactory	Significant
Gas distribution utilities and pipelines			
Inter Pipeline (Corridor) Inc.	A/Stable/--	Excellent	Significant
TransCanada Corp.	A-/Stable/--	Excellent	Significant
TransCanada PipeLines Ltd.	A-/Stable/A-2	Excellent	Significant
Gaz Metro Inc. and Gaz Metro L.P.	A-/Stable/--	Excellent	Significant
Enbridge Gas Distribution Inc.	A-/Stable/--	Excellent	Significant
Enbridge Pipelines Inc.	A-/Stable/--	Excellent	Significant
Enbridge Inc.	A-/Stable/--	Excellent	Significant
Union Gas Ltd.	BBB+/Stable/A-2	Strong	Significant
Westcoast Energy Inc.	BBB+/Stable/--	Strong	Significant
Trans Quebec & Maritimes Pipeline Inc.	BBB+/Stable/--	Strong	Significant
Valener Inc.	BBB+/Stable/--	Strong	Significant
Inter Pipeline Fund	BBB+/Stable/--	Strong	Significant
Veresen Inc.	BBB/Stable/--	Strong	Significant
TC PipeLines L.P.	BBB/Stable/--	Strong	Significant
Tuscarora Gas Transmission Co.	BBB/Stable/--	Satisfactory	Modest
Pembina Pipeline Corp.	BBB/Stable/--	Strong	Significant
AltaGas Ltd.	BBB/Stable/--	Strong	Significant
Niska Gas Storage Partners LLC	BB-/Stable/--	Fair	Aggressive

*Ratings as of June 21, 2012. §Business and financial risk profiles reflect the stand-alone credit risk profile as per our government-related entity criteria. †Debt rating. ‡Previously Chatham Kent Energy Inc.

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Industry Economic And Ratings Outlook:

U.S. Regulated Utilities Will Likely Stay On A Stable Trajectory For The Rest Of 2012 And Into 2013

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Table Of Contents

Industry Economic And Ratings Outlook:

U.S. Regulated Utilities Will Likely Stay On A Stable Trajectory For The Rest Of 2012 And Into 2013

Standard & Poor's Ratings Services' believes the outlook for credit quality in the U.S. investor-owned regulated electric, gas, and water utility sectors for the remainder of 2012 and into 2013 will remain stable. These companies have weathered the challenging economic environment of the past few years with little lasting effect on their financial risk profiles. The essential service that utilities provide and the rate-regulated nature of the business enable them to generate reasonably steady and predictable cash flows through timely recovery of their costs from ratepayers, despite economic conditions and ongoing heavy investment needs. As a result, we expect their credit quality to remain stable.

Economic Outlook

Standard & Poor's Ratings Services' base-case outlook for the remainder of 2012 and into 2013 for the U.S. investor-owned regulated electric, gas, and water utility sectors is stable based on the fundamentals described below. Our analysis of these utilities considers the general macroeconomic environment and, in particular, economic indicators that are most correlated with customer consumption. Standard & Poor's baseline assumptions that contribute to our current stable view of the regulated utilities include the following indicators:

- Real GDP growth of 2.04% in 2012 (from 1.74% in 2011) and 2.11% in 2013;
- An unemployment rate of 8.17% in 2012 and 8.04% in 2013;
- An increase in disposable income of 2.71% in 2012 and 2.84% 2013; and
- A still-weak housing market, with housing starts at around 750,000 in 2012 and 930,000 in 2013; and
- 10-year Treasury yield at 1.83% in 2012 and 2.17% in 2013.

In addition, we have assumed generally responsive regulatory decisions and continued solid liquidity and capital market access for this sector.

Although we expect the U.S. economy to remain sluggish with only modest growth in customer consumption, we anticipate ratings stability for the regulated utility sector based on our expectations of sustained demand for a very critical commodity, responsive regulatory attention to cost recovery for needed capital investments, and investors' continued appetite for utility debt and equity offerings.

Effects on ratings

U.S. regulated electric, gas and water utility companies' credit quality has continued its gradual shift toward greater stability. At the end of the second quarter of 2012, most U.S. investor-owned utility companies that we rate had stable outlooks. We took relatively few rating actions during the second quarter of 2012, and upgrades outpaced downgrades. We raised our corporate credit ratings on nine entities (both holding companies and operating subsidiaries--and five of these related to a single entity, Northeast Utilities) and lowered ratings on four (three of which related to NSTAR). The main reasons prompting the upgrades related to a merger with a stronger entity in the case of Northeast Utilities' (NU) upgrades; improving financial metrics; and reduced business risk. The downside actions were attributable to NSTAR's merger with lower rated NU, and with increased business risk at Spain-based Iberdrola S.A. given deteriorating economic conditions in Spain. In the past three months we revised several outlooks based on stronger financial metrics and improving business risk factors, placed ratings on CreditWatch, and removed ratings from CreditWatch.

The limited number of rating changes reflects an economic outlook that, despite a slow and uneven economic recovery, is stable in our base case. Our baseline forecast indicates slow economic growth and subdued job gains this year and into next. We're forecasting baseline real GDP growth to rise to 2.0% this year, which is a bit stronger than 1.74% in 2011, though much weaker than the 3% rate in 2010. For 2013, we expect 2.1% growth, which is much softer than our projection of 2.4% in May and reflects the stronger dollar and weaker growth from abroad that cuts into net export growth. The unemployment rate of 8.1% is two percentage points below its recession peak, though no notable improvement is likely in the foreseeable future. We also expect continuation of a weak housing market, high foreclosures, and only moderate increases in consumer spending in nearby years. While we continue to believe the risk of another recession in the U.S. is 20%, the outlook is better than it was late last year, when the recession risk was 40%. However, we believe that another recession is possible if the eurozone crisis spreads to the U.S. (and the rest of the world), if there's a sharp near-term spike in austerity measures in the U.S., or if financial markets lock up again. Under such a dire scenario, regulatory commissions will likely be reluctant to approve higher base rates for consumers. On the other hand, if the economy grows faster than we are expecting, regulatory risk could lessen as concerns about rate increases abate. (See the Economic Research article, "U.S. Risks To The Forecast: Lazy Hazy Crazy Days Of Summer," published June 25, 2012.)

Table 1

2012-2013 Scenarios For The U.S. Regulated Utilities Industry

	Forecast/scenarios*						Actual
	--Pessimistic--		--Baseline--		--Optimistic--		
	June 2012		June 2012		June 2012		
	2012	2013	2012	2013	2012	2013	2011
Macroeconomic indicators							
Real GDP (% change)	1.21	(0.03)	2.04	2.11	2.48	3.85	1.74
CPI (% change)	1.24	0.79	1.68	1.24	2.24	2.22	3.14
Core CPI (% change)	1.99	1.29	2.13	1.74	2.34	2.42	1.66
Number of households (mil.)	120.66	121.85	120.70	122.14	120.69	122.32	119.32
Yearly % change	1.13	0.98	1.16	1.19	1.15	1.35	0.82
ECI, wages and salaries (% change)	1.58	1.06	1.85	1.82	2.03	2.10	1.67
Unemployment rate (%)	8.37	9.08	8.17	8.04	8.01	7.00	8.95
Household obligations ratio (%)	15.29	13.89	15.29	14.11	15.30	14.54	16.08
Industry drivers							
Housing starts (mil. units)	0.67	0.62	0.75	0.93	0.81	1.23	0.61
Disposable income, 2005 $ (% change)	1.30	0.57	1.19	1.80	0.91	1.99	1.21
Disposable income (% change)	2.44	1.16	2.71	2.84	2.88	3.86	3.70
Consumer spending, electricity (% change)	(2.41)	2.78	(2.37)	3.86	(2.38)	4.60	0.97
Deflator electricity prices (% change)	(0.04)	0.63	0.08	1.38	0.20	2.29	1.82

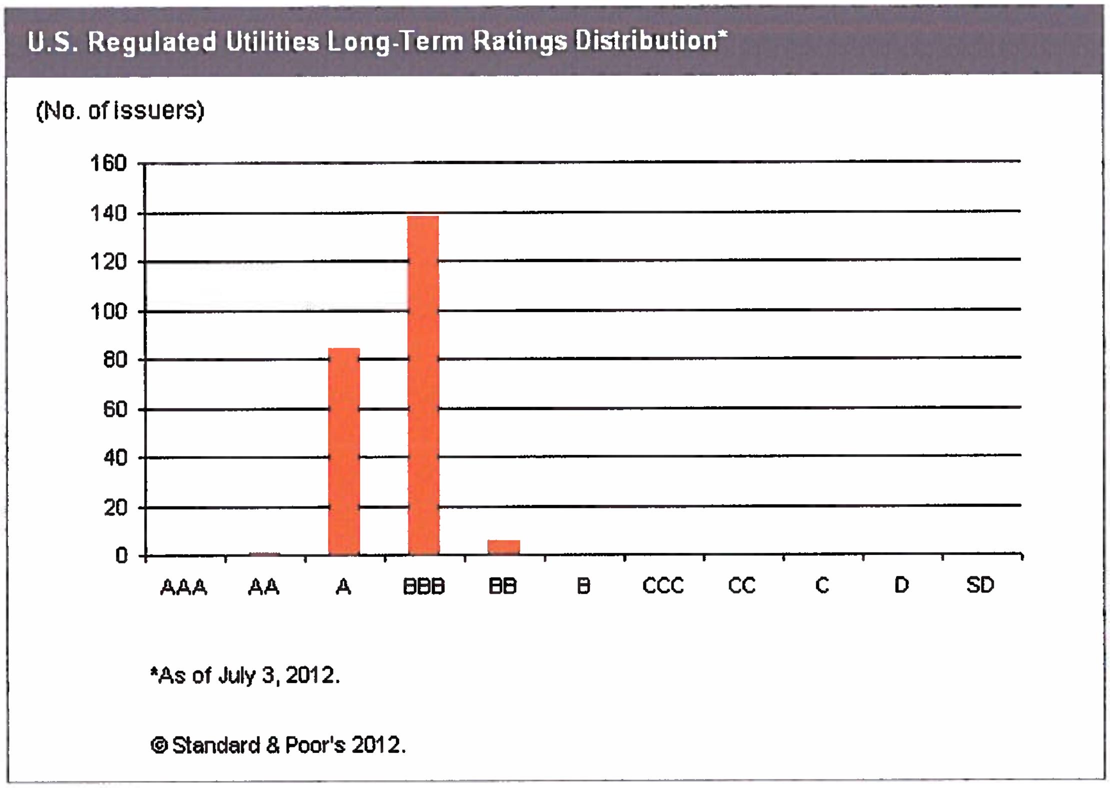
Table 1

2012-2013 Scenarios For The U.S. Regulated Utilities Industry (cont.)							
Natural gas % of electricity fuel use	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Coal % of electricity fuel use	0.44	0.44	0.44	0.44	0.44	0.44	0.45
Petroleum % of electricity fuel use	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Power plant nonresidential (% change)	9.28	(9.61)	9.57	(7.84)	9.78	(6.94)	17.89
Investment in public utilities (% change)	6.70	(6.44)	7.06	(4.41)	7.30	(3.22)	12.37
Investment in electric and gas utilities (% change)	8.81	(8.54)	9.09	(6.90)	9.31	(6.03)	16.17
Employment, utilities (mil.)	0.56	0.56	0.56	0.56	0.56	0.55	0.56
Employment, private (mil.)	110.82	110.82	111.24	113.02	111.33	114.45	109.25
PPI electricity (% change)	(0.34)	1.77	(0.18)	2.53	(0.03)	3.46	2.48
PPI coal (% change)	(0.66)	1.02	(0.45)	2.63	(0.27)	4.34	9.22
'BBB' bond yield (%)	5.21	5.41	5.07	5.12	5.34	5.81	5.66
10-yr. Treasury note yield (%)	1.56	1.66	1.83	2.17	2.22	3.59	2.79
BBB' interest rate spread (%)	3.65	3.76	3.24	2.95	3.11	2.22	2.88

S&P U.S. Economic team's forecasts are constructed using the Global Insight model of the U.S. economy. Industry Economic Table population process maintained by Quality Data Analytics. *Pessimistic and optimistic forecasts are from the "U.S. Risks To The Forecast: Lazy Hazy Crazy Days Of Summer," published on June 25, 2012, on RatingsDirect. Baseline forecast from the U.S. Monthly Forecast Report "Economic Meltdown?". PPI--Producer Price Index.

Standard & Poor's economists publish monthly scenarios of where we think the U.S. economy could be heading. Beyond projecting GDP and inflation, we also include outlooks for other major economic categories. We call this forecast our "baseline scenario," and we use it in all areas of our credit analyses (see table 1). Our current ratings in the regulated utility sectors factor in this scenario. However, we realize that financial market participants also want to know how we think the economy could worsen--or improve--from our baseline scenario. Any point-in-time forecast of the economy will be wrong; it is simply a question of how far wrong. As a result, we also project two additional scenarios, one upside and one downside. We set these scenarios approximately at one standard deviation from the base line (roughly the 20th and 80th percentile of the distribution of possible outcomes). We use the downside case to estimate the credit impact of an economic outlook that is weaker than the expected case.

Chart 1



Industry Credit Outlook

Our present ratings on U.S. regulated utility companies remain firmly entrenched at an average 'BBB+', notably higher than the average 'BB-' category for U.S. industrial companies. The higher ratings are attributable to the large percentage of utilities with "excellent" or "strong" business risk profiles under our criteria. Nonetheless, this is generally balanced with "aggressive" financial risk profiles under our criteria. As a consequence, some 60% of the industry carries a 'BBB' category corporate credit rating ('BBB+', 'BBB', and 'BBB-'), about 37% 'A-' and above, and just 3% non-investment grade ('BB+' and below).

The rating trend, as measured by outlooks and CreditWatch listings, is slightly negative, with approximately 4.8% of all rated domestic utilities having negative outlooks or negative CreditWatch listings. Nevertheless, about 90% of all utility companies carried a stable outlook at the end of June 2012. Therefore, we expect to take only a limited number of prospective rating actions in the near to intermediate term.

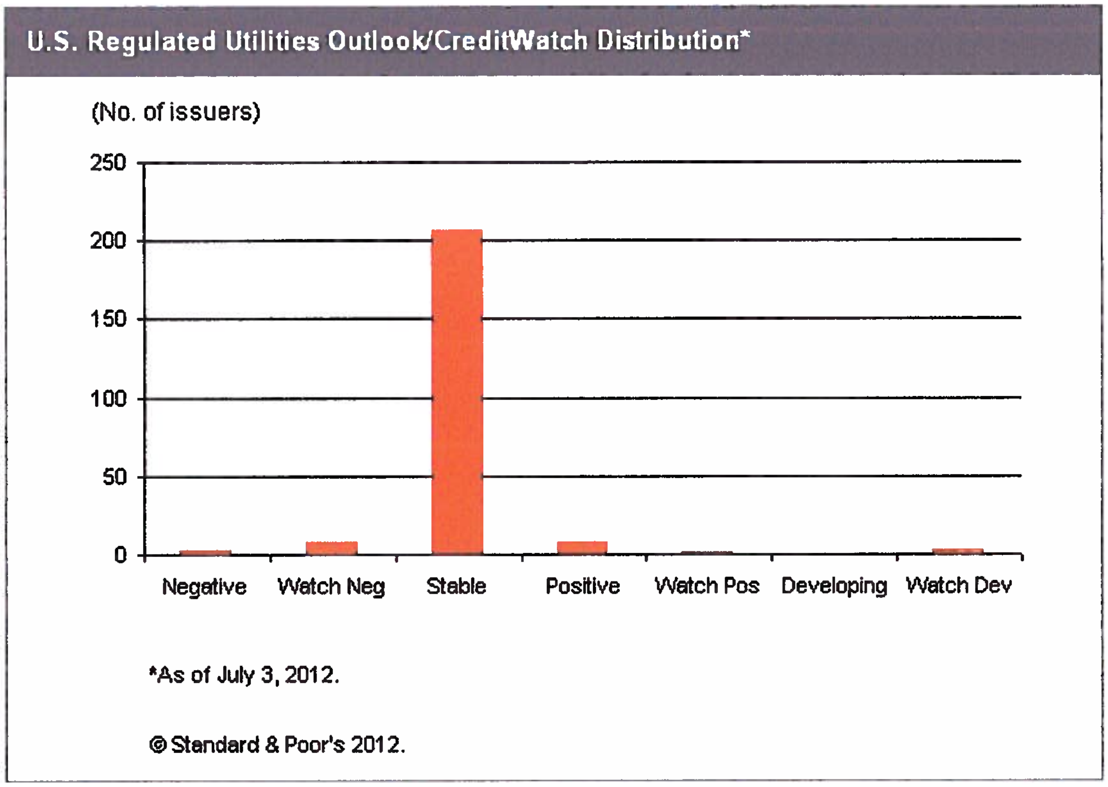
Liquidity is adequate for most utilities. Investor appetite for utility debt remains healthy, with deals continuing to be oversubscribed. The companies' near-term debt maturities appear manageable and we think they will likely refinance these with new debt or borrowings under revolving credit facilities. Credit fundamentals indicate that most, if not all, utilities should continue to have ample access to funding sources and credit. Some have issued common stock to partly fund construction expenditures, which has helped to support capital structure balance. Additionally, many companies are accessing short-term credit markets through commercial paper programs at very low rates. Liquidity is an industry strength and has been improving, and banks are indicating a willingness to lengthen the terms of credit facilities out as far as five years in more and more cases. U.S. regulated utilities have not been significantly hurt by turbulence in the global financial markets. We believe that utilities will continue to tap the short-term debt markets with relative ease following implementation of new bank regulations, though borrowing costs may rise. Utilities' ability to issue short-term debt and access liquidity is crucial, especially in light of the companies' increasing capital budgets to address rising investment requirements.

The amount of medium- to long-term debt issued by the domestic utility industry through June 30, 2012, was about $18.3 billion. Prospectively, we expect the industry's reliance on external capital to increase, largely due to projected increases in construction expenditures. Even if growth is slow, aging infrastructure and retirements of older inefficient coal-burning stations make investing necessary. For 2012, we expect that electric utilities will spend $85 billion, the gas sector will spend about $9.1 billion, and water companies some $1.8 billion.

The real challenge for the industry is the combination of slow growth and huge investment needs. We believe that for the remainder of 2012 and beyond, state regulation will continue to be the single most influential factor for the sector's credit quality. Cost increases, construction projects, environmental compliance, and other public policy directives, together with lackluster growth, will necessitate continued reliance on rate relief requests. Many recent rate orders and alternative rate mechanisms have been credit supportive. Although average returns on equity (ROE) have trended slightly downward, several jurisdictions have granted enhanced rate mechanisms that support greater cash flow stability and help utilities earn closer to their allowed ROEs. To the extent that the economy remains sluggish, use of innovative ratemaking techniques and large rate hikes will become increasingly critical to the sector's sustaining cash flow, earnings power, and ultimately, credit quality. In this regard, rate recovery mechanisms that allow for the timely adjustment of rates outside of a fully litigated rate proceeding because of changing commodity prices and other expenses will be particularly important to the sector's credit quality.

Our outlook for the electric, gas, and water industries is stable based on expectations on a continued slow economic recovery, generally supportive regulatory decisions that include mechanisms for timely cost recovery, receptive capital markets, and access to liquidity.

Chart 2



Recent Rating Activity

Merger-related actions

We lowered our ratings on NSTAR (A-/Stable A-2) and subsidiaries NSTAR Electric Co. and NSTAR Gas Co. to 'A-' from 'A+' and raised our ratings on Northeast Utilities (NU; A-/Stable A-2) and subsidiaries Connecticut Light & Power Co., Public Service Co. of New Hampshire, Western Massachusetts Electric Co., and Yankee Gas Services Co., to 'A-' from 'BBB+' after they received final regulatory approval for their all-stock merger. All ratings were removed CreditWatch where we placed them with negative and positive implications, respectively, on Oct. 18, 2010. Subsequent to the transaction, NSTAR was renamed NSTAR LLC, and NSTAR ceased to exist. As surviving entity, NSTAR LLC assumed all obligations that were previously issued by NSTAR, and became a subsidiary and an intraholding company of NU. The stable outlook is based on the company's consistent, regulated electric and natural gas businesses that have low operating risk and which we expect will generate cash flow that is sufficient for the ratings.

Given the large capital spending program and prospects for modest load growth, we expect that NU will generate consolidated adjusted funds from operations (FFO) to total debt of about 17%-18% over the next few years and adjusted total debt to total capitalization of below 54%. We will lower the ratings on NU if adjusted FFO to total debt declines below 15% on a consistent basis and debt leverage exceeds 55%. Given the company's heavy construction program, we don't anticipate an upgrade during our current forecast period. However, if adjusted FFO to total debt consistently exceeds 20%, we could raise the ratings by one notch.

Downgrades

We lowered our long-term corporate credit ratings on Iberdrola USA (BBB+/Stable/A-2) to 'BBB+' from 'A-' on May 3, 2012, when we lowered our ratings on parent Spain-based utility Iberdrola S.A. (BBB+/Stable/A-2) and subsidiaries. We removed the ratings from CreditWatch, where we placed them with negative implications on April 4, 2012.

The downgrades reflect our revision of our assessment of parent Iberdrola's business risk profile to "strong" from "excellent" under our criteria as a result of ongoing industry challenges and a deteriorating Spanish economy. We believe that the difficulties in Iberdrola's key domestic market could impair the group's profitability because it derives about 47% of revenues from its Spanish operations. We anticipate that Iberdrola's profit margins in its electricity generating unit could deteriorate in the near term, which is likely to squeeze the group's cash flows. In this segment, the group is exposed to what we see as increasingly difficult and volatile conditions in the liberalized and oversupplied Spanish electricity market. Furthermore, we think that the increase in the budget deficit that we foresee in Spain could increase political risk for sensitive industries such as utilities as the government implements fiscal austerity measures. Also, worsening economic conditions could add to regulatory uncertainty in a jurisdiction in which regulatory determinations are not independent from the government.

The stable outlook reflects our opinion that Iberdrola should be able to maintain FFO to debt of about 20%, which we view as commensurate with the ratings. We believe that the group can sustain this ratio despite industry and economic challenges, any potential delays in the receipt of proceeds from the securitization of the Spanish tariff deficit, and any further deficit accumulation. The rating on Iberdrola could remain unchanged even if we were to downgrade Spain by up to two notches. This is because under our criteria, there is a maximum possible rating differential of two notches between the ratings on Iberdrola and those on its related investment-grade sovereign in the eurozone. These criteria apply to Iberdrola because we assess it as having "high" exposure to domestic country risk. That said, in the event of a further downgrade of Spain, we would evaluate Iberdrola's credit quality separately from that of Spain.

Upgrades

We raised our ratings on PNM Resources Inc. (PNMR, BBB-/Stable/-) and subsidiaries Public Service Co. of New Mexico and Texas-New Mexico Power Co. to 'BBB-' from 'BB' on April 13, 2012. The upgrades reflect PNMR's lower business risk as a result of the company's focus on core electric operations following the previously completed divestitures of two unregulated businesses, as well as on its management of regulatory environments. We revised our assessment of the business risk profile to "excellent" under our criteria to reflect the consolidated entity's lower business risk. We believe the company will continue to maintain financial stability by targeting a 50% adjusted debt in the capital structure, bolstering operating cash flows through timely cost recovery, and improving regulatory relationships in New Mexico.

We raised our corporate credit ratings on Rochester Gas & Electric Corp. (RG&E, BBB+/Stable/--) to 'BBB+' from 'BBB' on April 24, 2012, as a result of improved financial measures, which we expect the company to maintain over the intermediate term, and a business profile that has benefited from constructive regulatory outcomes. A recent multiyear rate settlement includes several supportive recovery mechanisms that enhance the company's ability to earn its authorized ROE. We base our ratings on RG&E on the utility's stand-alone credit quality because the ultimate parent, Spanish utility holding company Iberdrola S.A., has assumed the debt of RG&E's parent company, Iberdrola USA. We regard the U.S. utility subsidiaries, which include RG&E, Central Maine Power Co., and New York State Electric & Gas Corp., as effectively under Iberdrola S.A.'s direct control, and none individually is a significant source of cash flow for the holding company. Our ratings on RG&E therefore do not reflect significant support from Iberdrola S.A., and we effectively cap them at the rating on the parent. RG&E's excellent business risk profile under our criteria benefits from a low-operating-risk transmission and distribution business strategy. The company's financial risk profile is aggressive in our assessment and we believe a sizable capital spending program could cause pressure. The stable outlook reflects improvement in bondholder protection parameters, decreasing regulatory risk, and our expectations that financial measures will remain in line with current results. Our baseline forecast shows FFO to total debt of 16%, debt leverage below 55%, and debt to EBITDA of 4x over the near-to-intermediate term. Fundamental to our forecast is the expectation that RG&E employ a low-risk strategy of investing in the regulated transmission and distribution business, maintaining its balanced capital approach, managing regulatory risk, and producing stable cash flow. We could lower the ratings if we see a decline in cash flow measures to a point where FFO to total debt falls below 15% and total debt to capital remains above 55% on a sustained basis.

Outlook revisions

We revised the outlook on Entergy Corp. (BBB/Stable/--) and its affiliates to stable from negative due to sustained improvement at the company's regulated utility operations at the same time it faced moderation in wholesale power prices and the relicensing process of two of its larger merchant nuclear plants, Indian Point Units 2 and 3. The company's business risk profile is firmly in the strong category under our criteria. The moderation in wholesale power prices increased the contribution of the regulated utility business to as much as 75% of operating income and cash flow, and we expect this trend to persist over the intermediate term. Despite the declining contribution of the merchant generation business, we do not view the overall level of business risk as declining. Nevertheless, given the combination of Entergy's strong business risk profile and significant financial risk profile under our criteria, we expect that the ratings can accommodate some of the uncertainty that surrounds the relicensing process as long as Entergy continues to effectively manage its regulated utility operations and merchant generation operations by, among other things, preserving its merchant hedging strategy while ensuring adequate liquidity. We expect that the consolidated financial risk profile will remain in the significant category over the next 12 to 24 months. Our baseline forecast is for adjusted FFO to total debt of just over 20% and adjusted total debt to total capital remaining at 60%. We could lower the ratings by one notch if a meaningful reduction in cash flow from the potential shut-down of Indian Point Units 2 and 3 when the licenses expire and further softness in the wholesale power markets results in adjusted FFO to total debt of below 18% on a sustained basis. We consider an upgrade unlikely given Entergy's current business mix and credit protection measures.

We revised our outlook on CMS Energy Corp. (BBB-/Positive/--) and subsidiary Consumers Energy Co. to positive from stable based on the company's effective management of regulatory risk, the gradual improvement in Michigan's economy, and our expectation that Michigan legislators won't lift the 10% customer choice cap—which limits the percent of sales that can be provided by alternative suppliers—in the intermediate term. The positive outlook indicates at least a one-in-three probability that we could raise the ratings over the next year if these expectations are sustained. Furthermore, the outlook reflects our baseline forecast that FFO to debt will generally be greater than 13% and debt to EBITDA will be consistently lower than 5x. We could raise the rating if the company is able to continue to manage its regulatory risk while maintaining FFO to debt of about 13%-15% and debt to EBITDA lower than 5x. Significant risks include rate case order outcomes and assumed continued economic stability. We would revise the outlook to stable if state legislators lift the 10% customer choice cap or FFO to debt drops below 12% on a sustained basis.

We revised our outlook on Wisconsin Energy Corp. (WEC; A-/ Positive/A-1) and subsidiaries Wisconsin Electric Power Co. and Wisconsin Gas LLC to positive from stable on June 7, 2012, based on our expectation of at least a one-in-three probability that the company will continue to achieve modest improvements in its financial measures that would support a one-notch upgrade over the intermediate term. Higher ratings are possible if the company continues to modestly reduce debt and strengthen its overall financial condition, if regulation in Wisconsin remains more credit supportive than in other states, and if the economy continues to show signs of sustained improvement. We could raise the ratings one notch within the next 12 to 18 months with sustained financial performance above our base-case forecast level of adjusted FFO to total debt of 23% and adjusted debt to total capital of about 55%. Fundamental to our forecast are expectations of a continued slow economic recovery in the company's service territory and a limitation of stock buybacks or dividend increases to those already announced by WEC, and the outcome of pending rate filings in Wisconsin and Michigan.

We revised the rating outlook on Ameren Corp. and regulated subsidiaries Ameren Illinois Co. and Ameren Missouri to stable from positive and affirmed the 'BBB-' ratings on April 3, 2012. At the same time, we affirmed the 'BB-' ratings on AmerenEnergy Generating Co., removed the ratings from CreditWatch with negative implications, and assigned a negative outlook. We view Ameren Corp.'s decision to offer liquidity to AmerenEnergy in the form of a put option with AmerenEnergy Resource Generating Co. (AERG) as solidifying AmerenEnergy's liquidity position. AmerenEnergy has the option to sell its combined cycle gas generating facility Grand Towers and gas peakers Elgin and Gibson City to AERG for a minimum of $100 million. This agreement demonstrates a credible liquidity plan, in our view. The stable rating outlook on Ameren takes into account continued weakness at AmerenEnergy and Ameren's willingness to provide cash to shore up AmerenEnergy's liquidity. The outlook also reflects a gradual improvement in the company's management of regulatory risk. We expect that parent Ameren will continue to support AmerenEnergy on a limited basis even over the longer term. Our ratings on AmerenEnergy reflect a stand-alone credit profile with limited support from parent Ameren Corp. Its stand-alone credit rating would be in the 'B' rating category without Ameren's support. The stable outlook on Ameren is based on our view that the company has reinforced its limited support for the subsidiary. The negative outlook on AmerenEnergy reflects the continued low price of electricity that materially stresses profit margins.

CreditWatch listings

Subsequent to the July 2, 2012, completion of the merger between Duke Energy Corp. (A-/Watch Neg/-A-2) and Progress Energy Inc. (BBB+/Watch Dev/A-2) we placed our ratings on Duke Energy and subsidiaries on CreditWatch with negative implications. At the same time, we revised the CreditWatch implications on Progress Energy and subsidiaries to developing from positive. Our rating actions were based on the abrupt change in executive leadership disclosed after the merger. The CreditWatch listings reflect unresolved issues on corporate governance, merger integration execution, and management of pending operational challenges. We are evaluating whether the combined entity warrants an excellent business risk profile under our criteria in light of potential integration challenges and corporate governance issues. Standard & Poor's expects to resolve the CreditWatch listings in the near term after a closer review and assessment of the implications of the change in leadership and its impact on the combined entity.

We placed our ratings on DPL Inc. (BBB-/Watch Neg/--) and subsidiary Dayton Power & Light Co. (DP&L) on CreditWatch with negative implications. The CreditWatch reflects the potential for a downgrade after we gain more clarity on the timing and transition to full market rates for DP&L. We revised our assessment of DPL and DP&L's business risk profiles to strong from excellent to reflect increased competition in Ohio along with expected growth of the unregulated retail business. We expect increasing competitive pressure due to lower wholesale electric prices will materially stress DPL's profit margins. DPL's financial position has little cushion due to the large amount of acquisition debt layered on by parent AES Corp. (BB-/Stable/--). Our baseline forecast shows FFO to total debt of around 11% and total debt to total capital at approximately 57%. We will resolve the CreditWatch when we have more clarity on the timing and transition to full market rates for DP&L.

Table 2

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Related Criteria And Research

- U.S. Risks To The Forecast: Lazy Hazy Crazy Days Of Summer, June 25, 2012
- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Assessing U.S. Utility Regulatory Environments, Nov. 7, 2007

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Issuer Ranking:

U.S. Regulated Utility Companies, Strongest To Weakest

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Issuer Ranking:

U.S. Regulated Utility Companies, Strongest To Weakest

The following list ranks all the rated companies in this industry from strongest to weakest based on rating and outlook. Companies with the same rating and outlook are further ranked by our opinion of credit quality based primarily on business risks for investment-grade companies and primarily on financial risks for speculative-grade companies.

Ratings are displayed as long-term rating/outlook or CreditWatch/short-term rating. A double dash (--) indicates no rating. Issuer credit ratings are identical for local and foreign currency unless noted with the "LC" and "FC" designations.

For the related industry report cards, see "Industry Report Card: U.S. Regulated Electric Utilities' Credit Quality Remains Stable," published March 28, 2012 and "Industry Report Card: U.S. Regulated Gas And Water Utilities' Credit Quality Should Remain Steady In 2012," published April 12, 2012.

U.S. Regulated Utilities

Company	Corporate credit rating*	Business risk profile	Financial risk profile	Liquidity
Madison Gas & Electric Co.	AA-/Stable/A-1+	Excellent	Intermediate	Adequate
Midwest Independent Transmission System Operator Inc.	A+/Stable/--	Excellent	Intermediate	Adequate
American Transmission Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
Aqua Pennsylvania Inc.	A+/Stable/--	Excellent	Intermediate	Adequate
Washington Gas Light Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
WGL Holdings Inc.	A+/Stable/A-1	Excellent	Intermediate	Adequate
The Baton Rouge Water Works Co.	A+/Stable/--	Excellent	Intermediate	Strong
American States Water Co.	A+/Stable/--	Excellent	Intermediate	Strong
Golden State Water Co.	A+/Stable/--	Excellent	Intermediate	Strong
Northwest Natural Gas Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
California Water Service Co.	A+/Negative/--	Excellent	Intermediate	Exceptional
-				
California Independent System Operator Corp.	A/Stable/--	Excellent	Intermediate	Adequate
San Diego Gas & Electric Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Southern California Gas Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Piedmont Natural Gas Co. Inc.	A/Stable/A-1	Excellent	Intermediate	Adequate
Questar Gas Co.	A/Stable/--	Excellent	Intermediate	Adequate
Alabama Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Georgia Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Mississippi Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Gulf Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
New Jersey Natural Gas Co.	A/Stable/A-1	Excellent	Intermediate	Adequate

U.S. Regulated Utilities (cont.)				
Laclede Gas Co.	A/Stable/A-1	Excellent	Intermediate	Strong
The Laclede Group Inc.	A/Stable/--	Excellent	Intermediate	Strong
The Brooklyn Union Gas Co.	A/Stable/--	Excellent	Intermediate	Adequate
KeySpan Gas East Corp.	A/Stable/--	Excellent	Intermediate	Adequate
Southern Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Questar Corp.	A/Stable/A-1	Excellent	Intermediate	Adequate
San Jose Water Co.	A/Stable/--	Excellent	Significant	Adequate
Connecticut Water Service Inc.	A/Negative/--	Excellent	Significant	Adequate
The Connecticut Water Co.	A/Negative/--	Excellent	Significant	Adequate
Central Hudson Gas & Electric Corp.	A/Watch Neg/--	Excellent	Significant	Strong
-				
Wisconsin Electric Power Co.	A-/Positive/A-2	Excellent	Significant	Adequate
Wisconsin Gas LLC	A-/Positive/A-2	Excellent	Significant	Adequate
Wisconsin Energy Corp.	A-/Positive/A-2	Excellent	Significant	Adequate
NSTAR Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Yankee Gas Services Co.	A-/Stable/--	Excellent	Significant	Adequate
NSTAR Electric Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Western Massachusetts Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
Connecticut Light & Power Co.	A-/Stable/--	Excellent	Significant	Adequate
Public Service Co. of New Hampshire	A-/Stable/--	Excellent	Significant	Adequate
Consolidated Edison Co. of New York Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Orange and Rockland Utilities Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
The York Water Co.	A-/Stable/--	Excellent	Significant	Adequate
Middlesex Water Co.	A-/Stable/--	Excellent	Significant	Adequate
United Water New Jersey Inc.	A-/Stable/--	Excellent	Significant	Adequate
United Waterworks Inc.	A-/Stable/--	Excellent	Significant	Adequate
Indiana Gas Co. Inc.	A-/Stable/--	Excellent	Significant	Adequate
Boston Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Colonial Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Vectren Utility Holdings Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Southern Indiana Gas & Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
Virginia Electric & Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Florida Power & Light Co.	A-/Stable/A-2	Excellent	Intermediate	Adequate
Massachusetts Electric Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Narragansett Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
New England Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Niagara Mohawk Power Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Northern States Power Wisconsin	A-/Stable/A-2	Excellent	Significant	Adequate
Public Service Co. of Colorado	A-/Stable/A-2	Excellent	Significant	Adequate
Northern States Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Southwestern Public Service Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Power & Light Co.	A-/Stable/A-2	Excellent	Significant	Adequate

U.S. Regulated Utilities (cont.)				
The Peoples Gas Light & Coke Co.	A-/Stable/A-2	Excellent	Significant	Adequate
North Shore Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Peoples Energy Corp.	A-/Stable/--	Excellent	Significant	Adequate
Wisconsin Public Service Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
MidAmerican Energy Co.	A-/Stable/A-2	Excellent	Significant	Adequate
PacifiCorp	A-/Stable/A-2	Excellent	Significant	Adequate
Northeast Utilities	A-/Stable/--	Excellent	Significant	Adequate
NSTAR LLC	A-/Stable/A-2	Excellent	Significant	Adequate
Consolidated Edison Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
National Grid USA	A-/Stable/A-2	Excellent	Significant	Adequate
National Grid Holdings Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
KeySpan Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Xcel Energy Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Integrys Energy Group Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Dominion Resources Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Vectren Corp.	A-/Stable/--	Excellent	Significant	Adequate
NextEra Energy Inc.	A-/Stable/--	Strong	Intermediate	Adequate
-				
Pennsylvania-American Water Co.	BBB+/Positive/--	Excellent	Significant	Adequate
New Jersey-American Water Co.	BBB+/Positive/--	Excellent	Significant	Adequate
American Water Works Co. Inc.	BBB+/Positive/A-2	Excellent	Significant	Adequate
American Water Capital Corp.	BBB+/Positive/A-2	Excellent	Significant	Adequate
Atlanta Gas Light Co.	BBB+/Stable/--	Excellent	Significant	Adequate
Nicor Gas Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Atmos Energy Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Tampa Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
International Transmission Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Midwest LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Michigan Electric Transmission Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Great Plains LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
CenterPoint Energy Houston Electric LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Cascade Natural Gas Corp.	BBB+/Stable/--	Excellent	Intermediate	Adequate
Montana-Dakota Utilities Co.	BBB+/Stable/--	Excellent	Intermediate	Adequate
Southwest Gas Corp.	BBB+/Stable/--	Excellent	Aggressive	Adequate
Interstate Power & Light Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Public Service Co. of North Carolina Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
South Carolina Electric & Gas Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Oncor Electric Delivery Co. LLC	BBB+/Stable/--	Excellent	Aggressive	Strong
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Southern California Edison Co.	BBB+/Stable/A-2	Excellent	Significant	Strong
Potomac Electric Power Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Delmarva Power & Light Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate

U.S. Regulated Utilities (cont.)				
Atlantic City Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Baltimore Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Central Maine Power Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
New York State Electric & Gas Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Rochester Gas & Electric Corp.	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Holdings Corp.	BBB+/Stable/--	Excellent	Aggressive	Adequate
AGL Resources Inc.	BBB+/Stable/A-2	Excellent	Significant	Adequate
MidAmerican Energy Holdings Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
TECO Energy Inc.	BBB+/Stable/--	Excellent	Significant	Adequate
SCANA Corp.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Alliant Energy Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
CenterPoint Energy Resources Corp.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
CenterPoint Energy Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
PEPCO Holdings Inc.	BBB+/Stable/A-2	Excellent	Significant	Adequate
South Jersey Gas Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
Michigan Consolidated Gas Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
Detroit Edison Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
Sempra Energy	BBB+/Stable/A-2	Strong	Intermediate	Adequate
DTE Energy Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
South Jersey Industries Inc.	BBB+/Stable/--	Strong	Significant	Adequate
OGE Energy Corp.	BBB+/Stable/A-2	Strong	Significant	Adequate
ALLETE Inc.	BBB+/Stable/A-2	Strong	Significant	Adequate
Duke Energy Kentucky Inc.	BBB+/Negative/--	Excellent	Significant	Adequate
Duke Energy Carolinas LLC	BBB+/Negative/A-2	Excellent	Significant	Adequate
Carolina Power & Light Co. d/b/a Progress Energy Carolinas Inc.	BBB+/Negative/A-2	Excellent	Significant	Adequate
Florida Power Corp. d/b/a Progress Energy Florida Inc.	BBB+/Negative/A-2	Excellent	Significant	Adequate
Duke Energy Indiana Inc.	BBB+/Negative/A-2	Strong	Significant	Adequate
Duke Energy Ohio Inc.	BBB+/Negative/A-2	Strong	Significant	Adequate
Progress Energy Inc.	BBB+/Negative/A-2	Excellent	Significant	Adequate
Duke Energy Corp.	BBB+/Negative/A-2	Excellent	Significant	Adequate
-				
Public Service Electric & Gas Co.	BBB/Positive/A-2	Excellent	Significant	Strong
Arizona Public Service Co.	BBB/Positive/A-2	Excellent	Aggressive	Adequate
Pinnacle West Capital Corp.	BBB/Positive/A-2	Excellent	Aggressive	Adequate
PECO Energy Co.	BBB/Stable/A-2	Excellent	Significant	Adequate
Commonwealth Edison Co.	BBB/Stable/A-2	Excellent	Significant	Adequate
PPL Electric Utilities Corp.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
AEP Texas Central Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
AEP Texas North Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Westar Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Kansas Gas & Electric Co.	BBB/Stable/--	Excellent	Aggressive	Adequate

U.S. Regulated Utilities (cont.)				
Connecticut Natural Gas Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
Southern Connecticut Gas Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
The United Illuminating Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Ohio Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kentucky Utilities Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Louisville Gas & Electric Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
LG&E and KU Energy LLC	BBB/Stable/--	Excellent	Aggressive	Adequate
Appalachian Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Green Mountain Power Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kentucky Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Public Service Co. of Oklahoma	BBB/Stable/--	Excellent	Aggressive	Adequate
Southwestern Electric Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kansas City Power & Light Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
KCP&L Greater Missouri Operations Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Entergy Gulf States Louisiana LLC	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Louisiana LLC	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Mississippi Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Arkansas Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Texas Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Entergy New Orleans Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Great Plains Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Cleco Power LLC	BBB/Stable/--	Excellent	Aggressive	Strong
Idaho Power Co.	BBB/Stable/A-2	Excellent	Aggressive	Strong
NorthWestern Corp.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Portland General Electric Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Avista Corp.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Puget Sound Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Idaho Power Co.	BBB/Stable/A-2	Excellent	Aggressive	Strong
El Paso Electric Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
PPL Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
UIL Holdings Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
American Electric Power Co. Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Cleco Corp.	BBB/Stable/--	Excellent	Aggressive	Strong
IDACORP Inc.	BBB/Stable/A-2	Excellent	Aggressive	Strong
System Energy Resources Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Corp.	BBB/Stable/--	Strong	Significant	Adequate
Pacific Gas & Electric Co.	BBB/Stable/A-2	Strong	Significant	Adequate
PG&E Corp.	BBB/Stable/--	Strong	Significant	Adequate
Indiana Michigan Power Co.	BBB/Stable/--	Strong	Aggressive	Adequate
-				
SEMCO Energy Inc.	BBB-/Watch Pos/--	Excellent	Significant	Adequate
Consumers Energy Co.	BBB-/Positive/--	Excellent	Aggressive	Adequate

U.S. Regulated Utilities (cont.)				
CMS Energy Corp.	BBB-/Positive/A-3	Excellent	Aggressive	Adequate
Trans-Allegheny Interstate Line Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
PNG Cos. LLC	BBB-/Stable/--	Excellent	Aggressive	Adequate
Bay State Gas Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Ameren Illinois Co.	BBB-/Stable/A-3	Excellent	Significant	Adequate
Ameren Missouri	BBB-/Stable/A-3	Excellent	Significant	Adequate
West Penn Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania Electric Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Metropolitan Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Jersey Central Power & Light Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Ohio Edison Co.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Cleveland Electric Illuminating Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Toledo Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Potomac Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Monongahela Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Duquesne Light Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Northern Indiana Public Service Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Black Hills Power Inc.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Otter Tail Power Co.	BBB-/Stable/--	Excellent	Significant	Strong
Empire District Electric Co.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Texas-New Mexico Power Co.	BBB-/Stable/--	Excellent	Aggressive	Strong
Public Service Co. of New Mexico	BBB-/Stable/--	Excellent	Aggressive	Strong
Indianapolis Power & Light Co.	BBB-/Stable/--	Excellent	Highly leveraged	Adequate
NiSource Inc.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Duquesne Light Holdings Inc.	BBB-/Stable/--	Excellent	Aggressive	Adequate
PNM Resources Inc.	BBB-/Stable/--	Excellent	Aggressive	Strong
IPALCO Enterprises Inc.	BBB-/Stable/--	Excellent	Highly leveraged	Adequate
Black Hills Corp.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Hawaiian Electric Co. Inc.	BBB-/Stable/A-3	Strong	Aggressive	Adequate
Edison International	BBB-/Stable/--	Strong	Aggressive	Strong
Ameren Corp.	BBB-/Stable/A-3	Strong	Significant	Adequate
FirstEnergy Corp.	BBB-/Stable/--	Strong	Aggressive	Adequate
Hawaiian Electric Industries Inc.	BBB-/Stable/A-3	Strong	Aggressive	Adequate
Ohio Valley Electric Corp.	BBB-/Stable/--	Strong	Aggressive	Adequate
Otter Tail Corp.	BBB-/Stable/--	Satisfactory	Significant	Adequate
Dayton Power & Light Co.	BBB-/Watch Neg/--	Strong	Aggressive	Adequate
DPL Inc.	BBB-/Watch Neg/--	Strong	Aggressive	Adequate
-				
SourceGas LLC	BB+/Stable/--	Excellent	Highly leveraged	Adequate
Nevada Power Co.	BB+/Stable/--	Excellent	Highly leveraged	Adequate
Sierra Pacific Power Co.	BB+/Stable/--	Excellent	Highly leveraged	Adequate

U.S. Regulated Utilities (cont.)				
NV Energy Inc.	BB+/Stable/--	Excellent	Highly leveraged	Adequate
Puget Energy Inc.	BB+/Stable/--	Excellent	Aggressive	Strong
Tucson Electric Power Co.	BB+/Stable/B-2	Strong	Aggressive	Adequate

*As of Aug. 6, 2012.

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Implications Of The Canadian Regulated Utility Sector's Mixed Bag Of Accounting Standards

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Table Of Contents

Implications Of The Canadian Regulated Utility Sector's Mixed Bag Of Accounting Standards

Several years ago the Accounting Standards Board in Canada (the AcSB), which is responsible for setting Canadian accounting standards, decided to adopt International Financial Reporting Standards (IFRS) and directed Canadian companies to provide financial information in accordance with IFRS starting with the first quarter of 2011. However, in response to significant lobbying, the AcSB decided to give qualifying rate-regulated entities the option to defer their adoption of IFRS until Jan. 1, 2012 (that is, they would first apply IFRS to their interim and annual financial statements relating to annual periods beginning on or after that date). In March 2012, the AcSB announced a second one-year deferral for qualifying rate-regulated entities to Jan. 1, 2013.

Both deferrals were optional. Entities that choose to defer application of IFRS continue to apply Part V of the Canadian Institute of Chartered Accountants Handbook--that is, Canadian Generally Accepted Accounting Principles (Canadian GAAP). Part V remains available for both rate-regulated and private companies. Further complicating matters, Canadian Securities Administrators permit Canadian public companies that have registered with the U.S.-based Securities Exchange Commission to use U.S. GAAP instead of Canadian GAAP.

Overview

- Canada's Accounting Standards Board decided to adopt IFRS effective Jan. 1, 2011, for all public companies in Canada. However, we believe some companies have chosen to move to U.S. GAAP rather than IFRS due to a deferral option only allowed under Canadian and U.S. GAAP for rate-regulated entities.
- Moreover, until fiscal year 2013 begins, reporting under Canadian GAAP remains a valid alternative. As a result, Canadian rate-regulated utilities are using a mixed bag of accounting standards.
- We do not anticipate any rating actions because of a change in accounting standards, and the changeover to either IFRS or U.S. GAAP is unlikely to affect financial ratios linked to cash flows, in our view. However, the changeover to IFRS or U.S. GAAP could affect ratios related to profitability and balance sheet measures.

So while many Canadian companies have already made the shift to IFRS, the utility sector has become a mixed bag: almost half are now reporting under U.S. GAAP in order to maintain access to the regulatory revenue deferral option, a few regulated utilities reported under Canadian GAAP in 2011, and others will continue with Canadian GAAP in 2012. This may leave readers with some questions—such as, why all the fuss? And what, if anything, does it mean for Standard & Poor's Ratings Services' credit analysis?

What's Behind The Deferral Option

Canadian GAAP includes specific guidance for rate-regulated entities that allows the deferral of costs and revenues to a future period when they can be matched to rate recovery. Before the AcSB decided to adopt IFRS, a company could declare a regulatory asset or liability if it had a high expectation of timely recovery. Since the sector has a long track record of regulatory approval of deferred assets and liabilities, most, if not all, Canadian utilities were able to avail themselves of this accounting option. Regulatory recovery disallowances have been very few and far between, and, in our view, largely immaterial to credit quality.

Such specific guidance is not a part of IFRS. Some Canadian rate-regulated entities had to choose to either apply the general rules in IFRS on presentation of financial statements (IAS 1), property, plant, and equipment (IAS 16), and intangible assets (IAS 38) or defer their adoption of IFRS for another year (that is, effective Jan. 1, 2013) with the expectation that IFRS would include guidance for rate-regulated entities by then.

Who's Affected?

The Canadian utilities sector includes the transmission and distribution of electricity and gas, electricity generation, and intra-provincial pipelines. These utilities are subject to regulation at the provincial level. Federal regulation under the National Energy Board supports interprovincial pipelines, and international pipelines are covered by federal regulation under the National Energy Board. Some provincial regulators, including the Ontario Energy Board (the OEB) and the Alberta Utilities Commission, provide guidance on rate-regulated accounting for companies reporting under IFRS.

A Snapshot Of The Accounting Standards Landscape In The Canadian Rate-Regulated Sector

Eight of the 14 rated utilities that have changed or will change over to IFRS from Canadian GAAP are government-owned and are under the OEB's jurisdiction. The OEB provided timely guidance on its version of modified IFRS for the purpose of rate setting, which facilitated the changeover. The other companies that have switched to IFRS are privately owned and under the jurisdiction of the Alberta Utilities Commission, which also provided some guidance.

Most of the companies that moved to U.S. GAAP either have U.S. holdings or some U.S. dollar denominated debt, are listed on a U.S.-based equity exchange, or, in the case of Union Gas Ltd. and Westcoast Energy Inc., have a U.S.-based parent.

At least four issuers have opted to continue using Canadian GAAP until the calendar year beginning Jan. 1, 2013: Gaz Metro Inc. and its related entities and ENMAX Corp. Gaz Metro is a reporting entity with some U.S.-based holdings and a Sept. 30 fiscal year end. ENMAX is a municipally-owned energy retailer in Alberta and is not a reporting entity. We believe these characteristics meant the somewhat tardy option (announced in March 2012) to defer IFRS implementation for a second year was a viable option for these companies (see charts 1 and 2 and table 1).

Chart 1

Accounting Standards Rated Canadian Rate-Regulated Issuers Elected At The Beginning Of Fiscal 2011

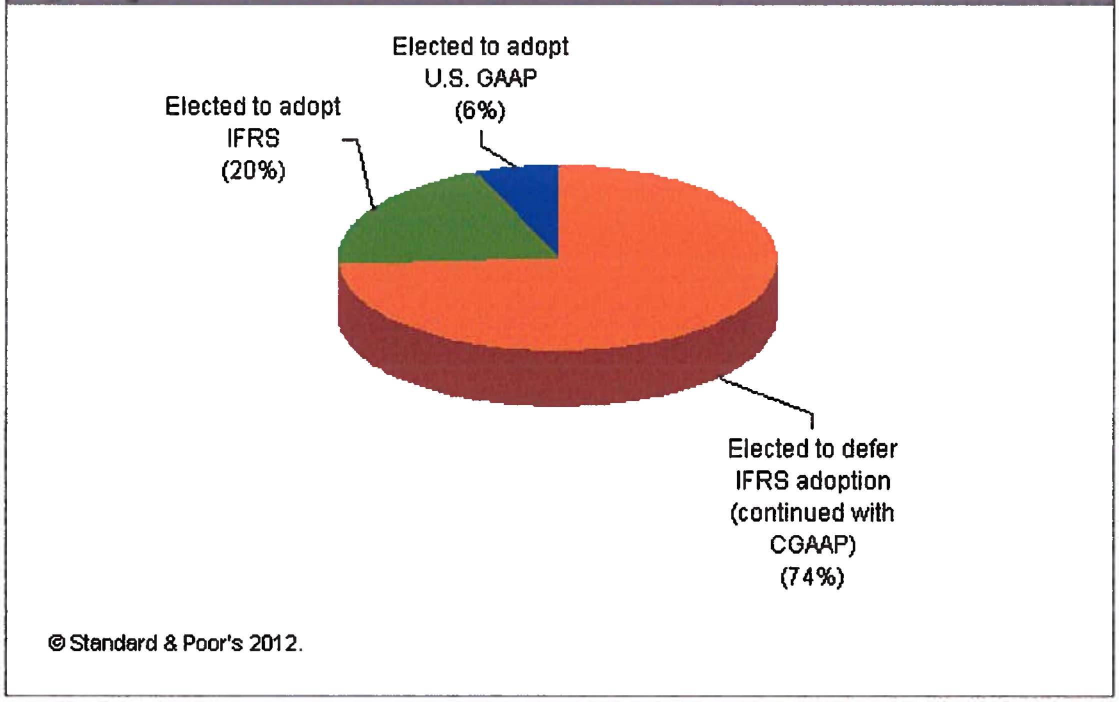

Chart 2

Accounting Standards Rated Canadian Rate-Regulated Issuers Elected At The Beginning Of Fiscal 2012

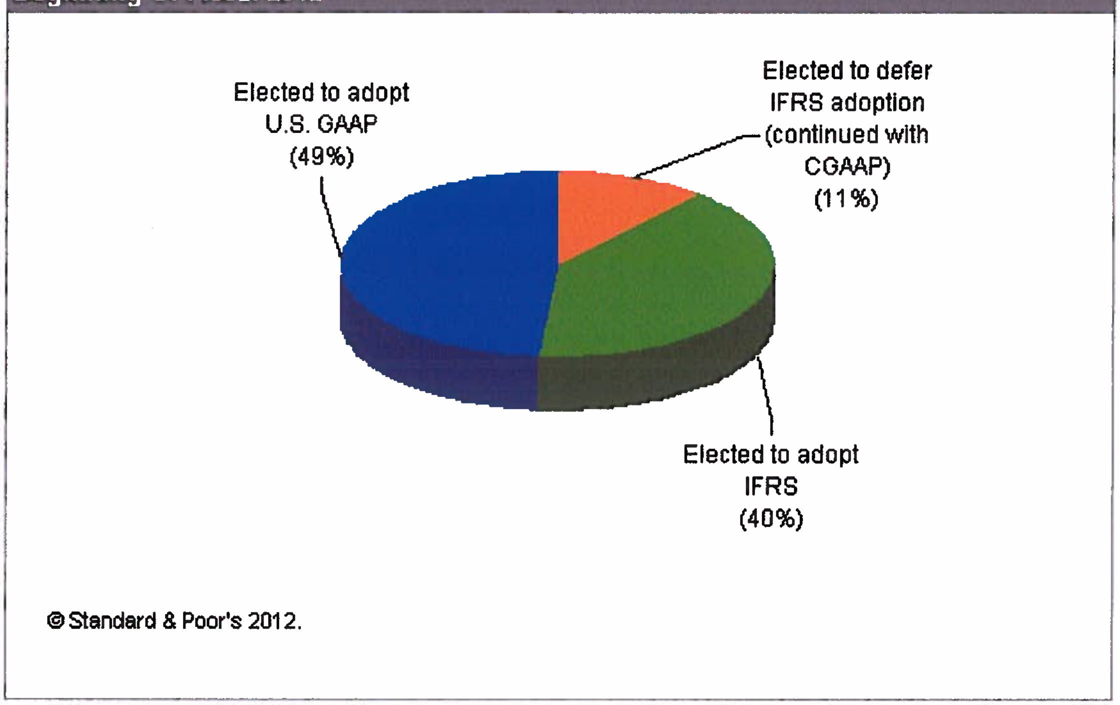

Table 1

Evolving Accounting Standards For Canadian Regulated Entities

	Accounting standards applied in fiscal year 2010	Accounting standards applied in fiscal year 2011	Accounting standards applied in fiscal year 2012
Rate-regulated entities that made an election in fiscal 2011:			
Altalink L.P.	CGAAP	IFRS	IFRS
Altalink Investments L.P.	CGAAP	IFRS	IFRS
ATCO Ltd.	CGAAP	IFRS	IFRS
Canadian Utilities Ltd.	CGAAP	IFRS	IFRS
CU Inc.	CGAAP	IFRS	IFRS
EPCOR Utilities Inc.	CGAAP	IFRS	IFRS
Guelph Hydro Electric Systems Inc.	CGAAP	IFRS	IFRS
Emera Inc.	CGAAP	US GAAP	US GAAP
Nova Scotia Power Inc.	CGAAP	US GAAP	US GAAP
Rate-regulated entities that elected to defer IFRS adoption in fiscal 2011 and made an election in fiscal 2012:			
Enersource Corp.	CGAAP	CGAAP	IFRS
Powerstream Inc.	CGAAP	CGAAP	IFRS
ENTEGRUS Inc.§	CGAAP	CGAAP	IFRS
Hamilton Utilities Corp.	CGAAP	CGAAP	IFRS
Horizon Holdings Inc.	CGAAP	CGAAP	IFRS
Hydro Ottawa Holding Inc.	CGAAP	CGAAP	IFRS
London Hydro Inc.	CGAAP	CGAAP	IFRS
AltaGas Ltd.	CGAAP	CGAAP	US GAAP
Enbridge Inc.	CGAAP	CGAAP	US GAAP
Enbridge Gas Distribution Inc.	CGAAP	CGAAP	US GAAP
Enbridge Pipelines Inc.	CGAAP	CGAAP	US GAAP
Fortis Inc.	CGAAP	CGAAP	US GAAP
FortisAlberta Inc.	CGAAP	CGAAP	US GAAP
Maritime Electric Co. Ltd.	CGAAP	CGAAP	US GAAP
Caribbean Utilities Co. Ltd.	CGAAP	CGAAP	US GAAP
Hydro One Inc.	CGAAP	CGAAP	US GAAP
Ontario Power Generation Inc.	CGAAP	CGAAP	US GAAP
Toronto Hydro Corp.	CGAAP	CGAAP	US GAAP
TransCanada Corp.	CGAAP	CGAAP	US GAAP
TransCanada Pipelines Ltd.	CGAAP	CGAAP	US GAAP
Westcoast Energy Inc.*	CGAAP	CGAAP	US GAAP
Union Gas Ltd.*	CGAAP	CGAAP	US GAAP
Rate-regulated entities that elected to defer IFRS adoption in fiscal 2011 and fiscal 2012:			
Valener Inc.	CGAAP	CGAAP	CGAAP
Trans Quebec & Maritimes Pipeline Inc.	CGAAP	CGAAP	CGAAP

Table 1

Evolving Accounting Standards For Canadian Regulated Entities (cont.)			
Gaz Metro Inc. and Gaz Metro L.P.	CGAAP	CGAAP	CGAAP
ENMAX Corp.	CGAAP	CGAAP	CGAAP

§Formerly known as Chatham Kent Energy Inc. *Subsidiaries of U.S. entity Spectra Energy Inc.

A Closer Look At IFRS

Pre-changeover Canadian GAAP and IFRS have several differences that warrant additional attention for Canadian rate-regulated entities that have adopted or plan to adopt IFRS (see table 2).

Table 2

Accounting Treatments Under Canadian GAAP Vs. IFRS

	Pre-changeover Canadian GAAP	IFRS	Analytical impact
Property, plant, and equipment	Canadian GAAP does not mention component accounting. Revaluation of assets is not permitted.	IFRS requires the use of component accounting for fixed assets, that is, the use of different useful lives for assets within the same category to arrive at a more precise depreciation charge each period. IFRS permits revaluation of property, plant, and equipment as an accounting policy choice that companies make and consistently apply thereafter.	A higher or lower depreciation charge may result. There will be no impact on EBITDA, FFO, or cash flow. Revaluations each reporting period could increase or decrease asset value and result in changes to the balance sheet unrelated to debt.
Asset retirement obligations (ARO) and decommissioning costs	The discount rate used to apply a present value to the obligation is the company's credit adjusted risk-free rate.	The discount rate used to apply a present value to the obligation is the risk-free rate.	The IFRS discount rate will likely result in additional liabilities and higher interest expense. There should be no impact on EBITDA or cash flows. However, our debt adjustment is likely to increase as the ARO increases, thereby affecting our debt ratios.
Asset impairments	Canadian GAAP includes a two-step approach to determine impairment. First, a comparison of the carrying value to the fair value of the underlying asset, and second, an impairment loss calculation if the carrying value is lower than the fair value. Undiscounted cash flows are used in the impairment model. Impairment loss reversal is not permitted.	A one-step approach is used under IFRS: a comparison of the carrying value to the fair value or value-in-use of the underlying asset. Any impairment loss is recorded immediately. Discounted cash flows are used in the impairment model. Impairment loss reversal is permitted.	Impairments may be more likely under IFRS but less significant, resulting in more frequent reductions in income and the carrying value of long-lived assets. There is no potential impact on cash flows.

We compared adjusted total debt-to-total capital and other key credit ratios for ATCO Ltd. under Canadian GAAP and IFRS for fiscal year 2010. The differences in our adjusted ratios are not material for this company (see tables 3 and 4).

Table 3

ATCO's Reported Debt Under Canadian GAAP And IFRS

	--As of Dec. 31, 2010--		
($ Mil.)	**CGAAP**	**IFRS**	**Variation**
Debt			
Long-term debt	3,514.5	3,515.0	0.5

Table 3

ATCO's Reported Debt Under Canadian GAAP And IFRS (cont.)			
Debt, reported	3,514.5	3,515.0	(0.5)
Standard & Poor's adjustments			
Plus: Operating leases	95.1	95.1	0.0
Plus: Intermediate hybrids reported as equity	430.0	424.0	6.0
Plus: Postretirement benefit obligations	218.4	213.1	5.3
Plus: Asset-retirement obligations	64.4	83.5	(19.2)
Debt, adjusted	4,322.4	4,330.8	(8.4)
Shareholder's equity			
Reported	3,073.9	2,826.0	247.9
Standard & Poor's adjustments			
Plus: Postretirement benefit obligations	(295.8)	0.0	(295.8)
Plus: Intermediate hybrids reported as equity	(430.0)	(424.0)	(6.0)
Plus: Minority interests	1,571.5	1,354.0	217.5
Shareholder's equity, adjusted	3,919.6	3,756.0	163.6
Debt to capital (%)			
Based on reported data	0.5	0.6	0.0
Based on Standard & Poor's adjusted data.	0.5	0.5	0.0

Table 4

ATCO's Adjusted Ratios Under Canadian GAAP And IFRS

Single-year ratios based on Standard & Poor's adjustments		EBITDA margin (%)	Return on capital (%)	EBIT interest coverage (x)	EBITDA interest coverage (x)	FFO/debt (%)	Free operating cash flow/debt (%)	Discounted cash flow/debt (%)	Debt/EBITDA (x)	Debt/debt plus equity (%)
IFRS	2010	38.0	11.0	3.4	4.7	22.9	2.8	(1.2)	3.3	53.6
CGAAP	2010	37.5	10.6	3.3	4.5	21.3	1.1	(3.0)	3.3	52.4
	Variation	0.5	0.4	0.1	0.2	1.6	1.7	1.8	(0.1)	1.1

The U.S. GAAP Alternative

Several Canadian utilities, particularly those with some investments in the U.S., have already transitioned to U.S. GAAP rather than moving to IFRS. Although pre-changeover Canadian GAAP guidance for rate-regulated entities was generally similar to that for U.S. GAAP, differences in certain other accounting areas could affect the credit metrics of Canadian companies moving to U.S. GAAP (see table 5).

Table 5

Accounting Treatments Under Canadian GAAP Vs. U.S. GAAP

	Pre-changeover Canadian GAAP	U.S. GAAP	Analytical impact
Joint venture accounting	Joint venture investments are accounted for using the proportionate consolidation method. Under the proportionate consolidation method, the investor's proportionate interest in the assets, liabilities, revenues, expenses, and cash flows of the investee are combined with similar items, line by line, in the investor's financial statements.	Joint venture investments are accounted for under the equity method if the reporting entity exerts significant influence over the venture or under the cost method if the entity does not exert significant influence.	If equity accounting is followed under U.S. GAAP, the value of assets, liabilities, revenues, and expenses will likely be lower. It may also change cash flows, unless all earnings of the venture are distributed.
Employee benefits plans	Actuarial gains and losses exceeding a certain threshold are charged to earnings as services are rendered (the corridor approach). Employers are not required to recognize the overfunded or underfunded status of defined benefit plans in the statement of financial position. The overfunded or underfunded status of a plan is included in the notes to the financial statements in the form of reconciliation to amounts recognized in the statement of financial position.	Actuarial gains and losses are recorded in other comprehensive income (OCI) and charged to earnings as services are rendered. Employers are required to recognize the overfunded or underfunded status of a defined benefit plan as an asset or liability in the statement of financial position. Changes in the funded status, net of the related tax effects, are recognized through OCI.	U.S. GAAP will eliminate a gradual impact of actuarial gains and losses from the income statement to OCI. There will likely be no impact on cash flows. However, there will be a one-time effect from the recognition of the overfunded or underfunded status on U.S. GAAP adoption.
Debt issuance cost	Long-term debt financing fees are netted against the principal balance outstanding.	Long-term debt financing fees are reported as a deferred asset.	Recognition of debt financing fees as an asset will likely increase the debt amount under U.S. GAAP. However, we do not believe such a change in accounting will affect our debt adjustment because our analysis already considers this accounting difference. There will likely be no impact on cash flows.
Uncertainty in income taxes	There is no prescribed method to account for income tax uncertainties. There are no specific disclosure requirements beyond the requirements for contingent liabilities.	There is a method for companies to recognize, measure, present, and disclose uncertain tax positions that they have taken or expect to take on a tax return.	This change may accelerate recognition of liabilities and result in greater volatility in earnings. There will likely be no impact on cash flows.

We compared Standard & Poor's adjusted total debt-to-total capital and other key credit ratios for Nova Scotia Power Inc. under Canadian GAAP and U.S. GAAP for the fiscal year 2010 (see tables 6 and 7). The key difference in reported data for this company relates to the change in accounting for postretirement benefit obligations under Canadian and U.S. GAAP. Given our standard approach to shareholder's equity under pre-changeover Canadian GAAP, we adjust equity for the difference between the amount accrued on the balance sheet and amount of net over/under funded postretirement obligation (net surplus/deficit), net of tax. Companies following U.S. GAAP record the unfunded postretirement obligation on the balance sheet while companies following IFRS have the option to fully recognize actuarial gain/losses on their balance sheets. Accordingly, our equity adjustment is not required under U.S. GAAP or IFRS. However, the difference in our adjusted ratios under the two accounting standards is not material.

Table 6

Nova Scotia Power's Reported Debt Under Canadian GAAP And IFRS

	--As of Dec. 31, 2010--		
($ Mil.)	CGAAP	U.S. GAAP	Variation
Debt			
Short-term debt	48.4	48.4	0.0
Long-term debt	1,933.7	1,949.1	15.4

Table 6

Nova Scotia Power's Reported Debt Under Canadian GAAP And IFRS (cont.)			
Debt, reported	1,982.1	1,997.5	15.4
Standard & Poor's adjustments			
Plus: Operating lease adjusted debt	2.6	2.6	(0.0)
Plus: Asset-retirement obligations debt adjustment	91.5	91.5	(0.0)
Plus: 50% of intermediate-equity hybrid reported as equity	67.5	66.1	(1.4)
Plus: Pension and other postretirement debt/deferred compensation	213.1	213.1	(0.0)
Debt, adjusted	2,356.9	2,370.8	13.9
Shareholders' equity			
Reported	1,346.5	957.0	(389.5)
Standard & Poor's adjustments			
Intermediate hybrids reported as equity	(67.5)	(66.1)	1.4
Postretirement benefit obligations/deferred compensation	(244.4)	0.0	244.4
Shareholders' equity, adjusted	1,034.6	890.9	(143.7)
Debt to debt plus equity (%)			
Based on reported data	59.5	67.6	8.1
Based on Standard & Poor's adjusted data	69.5	72.7	3.2

Table 7

Nova Scotia Power's Adjusted Ratios Under Canadian GAAP And IFRS

Single-year ratios based on Standard & Poor's adjustments		EBITDA margin (%)	Return on capital (%)	EBIT interest coverage (x)	EBITDA interest coverage (x)	FFO/debt (%)	Free operating cash flow/debt (%)	Discounted cash flow/debt (%)	Debt/EBITDA (x)	Debt/debt plus equity (%)
U.S. GAAP	2010	33.6	7.5	1.9	3.5	14.5	(4.2)	(8.6)	5.5	72.7
CGAAP	2010	34.0	7.0	1.8	3.5	14.6	(3.9)	(8.3)	5.4	69.5
	Variation	(0.4)	0.6	0.1	(0.0)	(0.1)	(0.3)	(0.3)	0.1	3.2

Analytical Considerations And The Impact On Standard & Poor's Ratios

Changes in accounting standards can affect our adjusted ratios on each company we rate.

Income statement impact

The ability or inability to recognize deferred revenues and expenses that have a high expectation of recovery due to regulatory support -- which we believe is a key factor behind utilities' move to U.S. GAAP rather than IFRS – and its impact on our adjusted ratios do not directly affect our credit analysis. Although the recognition of regulatory deferrals (also reported as regulated assets and liabilities on the balance sheet) does result in income statement smoothing, our credit analysis focuses more on the certainty of timely recovery. However, since a regulatory asset does represent cash spent and not yet recovered and a regulatory liability does represent cash collected that must be repaid to consumers, we do monitor the recovery of material regulatory deferrals and factor the degree of regulatory support into our ratings. We examine the track record of the company in estimating prudent costs that it can recover through regulated tariffs, and of the regulator in approving the timely recovery or repayment. An accumulation of material deferred assets could heighten regulatory recovery risk if the anticipated impact on customer rates is significant. Similarly, an accumulation of material regulatory liabilities could potentially pose a strain on the utility if the company is directed to repay customers over a short time frame and does not have the liquid resources available. As a result, we view as higher risk a company with large deferred assets or liabilities in a regulatory regime where the utility's spending may be questioned by the regulator and a recovery spread of more than three to five years, compared with a company under a regulatory jurisdiction with a strong track record of negligible disallowances and short recovery periods (months for fuel/commodity costs, one to three years for material unexpected costs). We also view the ability to earn a regulated return on these assets, allowed in some jurisdictions, as positive.

Cash flow impact

We expect that a changeover to either IFRS or U.S. GAAP will not significantly affect cash flow credit metrics because multiple accounting differences in each standard tend to offset each other. For example, component accounting for fixed assets under IFRS can increase depreciation expense but at the same time will reduce net income. Both changes are included in cash flows from operations and therefore we don't expect them to result in a net change in cash flows from operations.

For some small municipally-owned regulated local distribution companies (LDC) in Ontario, the conversion to IFRS has resulted in significantly lower depreciation expense due to the recognition of longer useful lives of fixed assets more in line with their peers. In addition, IFRS recognition of certain overhead costs, previously capitalized under Canadian GAAP, increases LDC's operating expense. The net impact varies depending on the magnitude of the respective changes on a company- by- company basis but in general, we expect these differences to largely offset each other.

Profitability and balance sheet

With changing accounting and financial reporting classifications and values, IFRS adoption could affect ratios related to profitability and balance sheet measures. We expect companies will manage the transition with their banks without compromising compliance with banking facility covenants.

To date the differences in our adjusted ratios for regulated utilities now reporting under IFRS or U.S. GAAP instead of Canadian GAAP have not been material. However, year-over-year and intercompany comparisons of our total debt-to-total capital ratio need to be made carefully because of the differences in the derivation under Canadian GAAP and U.S. GAAP vis a vis IFRS. Furthermore, under IFRS this gearing ratio can fluctuate from period to period due to changes in reported equity rather than a change in financial policy or cash flow strength.

More Accounting Changes Are Possible

With Canadian regulated utilities using a mixed bag of accounting standards, we approach credit metric comparisons with caution -- but we do not anticipate taking any rating actions. Further accounting changes are possible depending on the AcSB's final decision regarding regulatory deferrals under IFRS. In the meantime, we are likely to continue to see almost half the sector reporting under U.S. GAAP.

Related Criteria And Research

- Standard & Poor's Ratings Services Generally Favors SEC Staff Paper On Condorsement, But We Are Concerned About Long Transition And Prospective Application, Aug. 8, 2011
- Credit FAQ: IFRS Voyage Begins As Canada Embarks On Accounting Transition, March 31, 2011
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009

Attachment 47.5

AGL Resources:

2011: Merged with NICOR, which owned Nicor Gas, a large Illinois gas distributor

2004: Acquired NUI Corp., which included the utilities Elizabethtown Gas (New Jersey), Florida City Gas (Florida) and Elkton Gas (Maryland).

2001: Created Sequent Energy Management, a subsidiary whose function is to provide gas asset optimization services to large purchasers of gas sales, transportation and storage services.

1998: Retail gas marketing subsidiary formed.

1997: Atlanta Gas Light subsidiary becomes “pipes” only utility.

Alliant Energy Corp:

2007: Agrees to sell electricity transmission assets to ITC Midwest.

2007: Agrees to sell remainder of international investments.

2006: Sells entire investment in Brazil.

2000: Buys a 49% interest in four Brazilian electric utilities.

1998: Merger of WPL Holdings, IES Industries, and Interstate Power from Interstate Energy Corporation.

Atmos Energy Corp:

2004: Acquired the utility and pipeline operations of TXU Gas.

2002: Acquired Mississippi Valley Gas Company.

2001: Acquired Louisiana Gas Service Company and LGS Natural Gas Company.

2000: Acquired Natural Gas-Missouri operations.

1997: Merges with United Cities Gas Company.

Consolidated Edison Inc:

1999: Company sells their fossil-fuel plants in New York City.

1999: Acquires Orange & Rockland Utilities.

1998: Holding company Consolidated Edison Inc. is formed.

Integrys Energy Group Inc:

2008: Nonregulated subsidiary Integrys Energy Services scaled back

2007: Integrys Energy Group established with the merger of WPS Resources Corporation and Peoples Energy Corporation.

2006: WPS Resources acquires Michigan Gas Utilities.

2006: WPS Resources acquires Minnesota Energy Resources.

2001: WPS Resources acquires Wisconsin Fuel & Light.

1998: WPS Resources acquires Upper Peninsula Power Company.

Northwest Natural Gas Co:

None

Piedmont Natural Gas Co:

2010: Sold a large portion of their stake in Southstar Energy Holdings.

2003: Completed the purchase of North Carolina Natural Gas.

Southern Co:

2005: Sold their retail gas market subsidiary Southern Company Gas.

2001: Formed Southern Power, a subsidiary to own, manage, and finance wholesale generation assets.

2001: Completed spinoff of Southern Energy Inc, an independent power producers and energy marketing company.

Vectren Corp:

2006: Purchased Duke Energy's interest in Miller Pipeline.

2000: Acquired the natural gas distribution assets of Dayton Power and Light.

2000: Vectren is formed by the merger of Indiana Energy and SIGCORP.

WGL Holdings:

2000: WGL Holdings is established as parent holding company for Washington Gas Light Company.

1996: Sold West Virginia distribution assets to Mountaineer Gas.

Wisconsin Energy Corp:

2010: Completes the sale of Edison Sault Electric Company.

2007: Completes the sale of Point Beach Nuclear Plant to FPL Energy.

2004: Sells WICOR Industries, a manufacturer of water systems.

2000: Wisconsin Gas becomes part of Wisconsin Energy Corporation.

1998: Buys ESELCO, parent company of Edison Sault Electric.

Xcel Energy Inc:

2005: Sells Seren Innovations Inc, a telecommunications company.

2003: Subsidiary NRG Energy declares Chapter 11 bankruptcy.

2000: Xcel Energy is created by the merger of Northern States Power and New Century Energies.

Attachment 47.5b

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR SAMPLE OF U.S. UTILITIES

Company Name	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
AGL Resources Inc.	11.9	11.1	11.6	4.9	13.2	12.7	12.6	11.3	11.1	13.8	14.9	16.4	13.1	13.4	13.6	12.9	13.1	12.9	13.0	6.7
Alliant Energy Corp.	13.9	12.5	11.1	9.8	11.9	10.1	8.7	10.5	18.2	9.4	5.7	9.0	5.9	-0.3	12.4	16.0	10.5	4.0	10.2	10.3
Atmos Energy Corp.	10.8	14.7	11.0	12.3	14.5	9.5	15.8	4.7	9.3	11.5	10.3	11.1	8.7	9.9	9.1	9.3	9.0	9.0	9.5	9.4
Consolidated Edison	13.6	13.2	13.5	12.7	12.2	11.9	11.9	12.3	10.7	12.3	11.5	8.5	8.0	10.0	9.6	10.9	12.7	8.7	9.3	9.3
Integrys Energy Group Inc.	16.1	14.8	12.0	12.2	10.3	11.4	9.4	11.3	12.4	12.3	14.6	10.2	13.3	13.3	11.0	10.5	4.0	-2.4	7.7	7.8
Northwest Natural Gas	6.1	14.4	12.2	11.8	13.1	11.3	6.4	10.2	10.8	10.4	8.7	9.2	9.4	10.1	10.7	12.5	11.4	11.7	10.7	9.1
Piedmont Natural Gas	14.0	13.7	12.1	12.3	13.1	13.4	13.7	12.3	12.6	12.0	10.8	12.2	12.8	11.6	11.0	11.9	12.5	13.5	15.0	11.6
Southern Company	16.4	14.8	12.5	13.0	12.5	10.3	10.0	13.4	13.2	13.5	15.8	16.1	15.4	15.2	14.3	14.6	13.6	11.7	12.7	13.0
Vectren Corp.	NA	NA	NA	NA	NA	NA	NA	NA	13.8	8.5	13.3	11.5	10.0	12.2	9.4	11.9	10.0	9.7	9.4	9.8
WGL Holdings Inc.	12.9	12.5	12.5	12.3	15.0	14.1	11.2	10.4	11.9	11.0	5.0	14.2	11.6	11.8	9.6	11.3	11.5	11.2	9.8	9.9
Wisconsin Energy Corp.	11.6	11.9	10.7	12.9	11.4	3.2	10.0	10.7	7.7	10.2	8.0	10.9	12.6	11.9	11.4	11.2	11.2	11.1	12.4	13.6
Xcel Energy Inc.	11.0	12.4	12.4	13.4	12.6	10.0	11.4	8.7	13.3	13.3	-40.9	12.6	6.8	9.6	10.1	9.5	9.7	9.5	9.8	10.1

Source: Standard and Poor's Research Insight.

Regulatory Decisions 1993-2012

Corporate Name	Subsidiary	State	Date of Decision	Docket Number	Type	ROE Allowed	Common Equity Ratio Allowed
AGL Resources Inc.	Atlanta Gas Light Co.	GA	03/11/2010	D-31647	Natural Gas	10.75	51.00
AGL Resources Inc.	Atlanta Gas Light Co.	GA	10/06/2005	D-18638-U	Natural Gas	10.90	NA
AGL Resources Inc.	Atlanta Gas Light Co.	GA	29/04/2002	D-14311-U	Natural Gas	11.00	47.00
AGL Resources Inc.	Atlanta Gas Light Co.	GA	30/06/1998	D8390-U	Natural Gas	11.00	43.88
AGL Resources Inc.	Atlanta Gas Light Co.	GA	29/09/1993	D-4451-U	Natural Gas	11.00	42.97
AGL Resources Inc.	Chattanooga Gas Co.	TN	24/05/2010	D-09-00183	Natural Gas	10.05	46.06
AGL Resources Inc.	Chattanooga Gas Co.	TN	05/12/2006	D-06-00175	Natural Gas	10.20	44.80
AGL Resources Inc.	Chattanooga Gas Co.	TN	20/10/2004	D-04-00034	Natural Gas	10.20	35.50
AGL Resources Inc.	Chattanooga Gas Co.	TN	07/10/1998	D-97-00982	Natural Gas	11.06	44.16
AGL Resources Inc.	Chattanooga Gas Co.	TN	25/01/1994	D-93-06946	Natural Gas	12.00	43.82
AGL Resources Inc.	Northern Illinois Gas Co.	IL	25/03/2009	D-08-0363	Natural Gas	10.17	51.07
AGL Resources Inc.	Northern Illinois Gas Co.	IL	30/09/2005	D-04-0779	Natural Gas	10.51	56.37
AGL Resources Inc.	Northern Illinois Gas Co.	IL	03/04/1996	D-95-0219	Natural Gas	11.13	58.08
AGL Resources Inc.	Pivotal Utility Holdings Inc.	FL	09/02/2004	D-030569-GU	Natural Gas	11.25	36.77
AGL Resources Inc.	Pivotal Utility Holdings Inc.	FL	05/02/2001	D-000768-GU	Natural Gas	11.50	37.39
AGL Resources Inc.	Pivotal Utility Holdings Inc.	FL	29/10/1996	D-960502-GU	Natural Gas	11.30	35.04
AGL Resources Inc.	Pivotal Utility Holdings Inc.	FL	29/11/1994	D-940276-GU	Natural Gas	11.30	29.33
AGL Resources Inc.	Pivotal Utility Holdings Inc.	NJ	17/12/2009	D-GR-09030195	Natural Gas	10.30	47.89
AGL Resources Inc.	Pivotal Utility Holdings Inc.	NJ	20/11/2002	D-GR-02040245	Natural Gas	10.00	NA
AGL Resources Inc.	Virginia Natural Gas Inc.	VA	20/12/2011	C-PUE-2010-00142	Natural Gas	10.00	45.36
AGL Resources Inc.	Virginia Natural Gas Inc.	VA	24/07/2006	C-PUE-2005-00057	Natural Gas	10.00	44.96
AGL Resources Inc.	Virginia Natural Gas Inc.	VA	28/04/1998	C-PUE-960227	Natural Gas	10.90	54.94
AGL Resources Inc.	Virginia Natural Gas Inc.	VA	31/01/1996	C-PUE-940054	Natural Gas	11.30	59.16
AGL Resources Inc.	Virginia Natural Gas Inc.	VA	22/06/1993	C-PUE-920031	Natural Gas	11.75	56.79
Alliant Energy Corp.	Interstate Power & Light Co.	IA	15/12/2010	D-RPU-2010-0001	Electric	10.44	44.24
Alliant Energy Corp.	Interstate Power & Light Co.	IA	04/01/2010	D-RPU-2009-0002	Electric	10.80	49.52
Alliant Energy Corp.	Interstate Power & Light Co.	IA	14/10/2005	D-RPU-05-1	Natural Gas	10.40	49.35
Alliant Energy Corp.	Interstate Power & Light Co.	IA	14/12/2004	D-RPU-04-1	Electric	10.97	47.89
Alliant Energy Corp.	Interstate Power & Light Co.	IA	15/05/2003	D-RPU-02-7	Natural Gas	11.05	47.84
Alliant Energy Corp.	Interstate Power & Light Co.	IA	15/04/2003	D-RPU-02-3	Electric	11.15	47.20
Alliant Energy Corp.	Interstate Power & Light Co.	IA	04/12/1995	D-RPU-95-1	Electric	11.35	45.39
Alliant Energy Corp.	Interstate Power & Light Co.	IA	12/05/1995	D-RPU-94-2	Electric	11.63	49.12
Alliant Energy Corp.	Interstate Power & Light Co.	IA	03/06/1994	D-RPU-93-6	Electric	11.00	44.30
Alliant Energy Corp.	Interstate Power & Light Co.	IA	01/09/1993	D-RPU-92-11	Natural Gas	11.25	44.26
Alliant Energy Corp.	Interstate Power & Light Co.	IA	03/05/1993	D-RPU-92-9	Natural Gas	11.75	43.59
Alliant Energy Corp.	Interstate Power & Light Co.	MN	12/08/2011	D-E-001/GR-10-276	Electric	10.35	47.74
Alliant Energy Corp.	Interstate Power & Light Co.	MN	03/03/2006	D-E-001-GR-05-748	Electric	10.39	49.10
Alliant Energy Corp.	Interstate Power & Light Co.	MN	05/04/2004	D-E-001/GR-03-767	Electric	11.25	47.15
Alliant Energy Corp.	Interstate Power & Light Co.	MN	08/04/1996	D-E-001-GR-95-601	Electric	11.00	41.06
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	15/06/2012	D-6680-UR-118	Electric	10.40	49.31
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	15/06/2012	D-6680-UR-118	Natural Gas	10.40	49.31
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	18/12/2009	D-6680-UR-117	Electric	10.40	50.38
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	18/12/2009	D-6680-UR-117	Natural Gas	10.40	50.38
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	19/01/2007	D-6680-UR-115	Electric	10.80	54.13
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	19/01/2007	D-6680-UR-115	Natural Gas	10.80	54.13
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	19/07/2005	D-6680-UR-114	Electric	11.50	61.75
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	19/07/2005	D-6680-UR-114	Natural Gas	11.50	61.75
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	19/12/2003	D-6680-UR-113	Electric	12.00	60.27
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	19/12/2003	D-6680-UR-113	Natural Gas	12.00	60.27
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	03/04/2003	D-6680-UR-112	Electric	12.00	51.72
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	03/04/2003	D-6680-UR-112	Natural Gas	12.00	51.72
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	12/09/2002	D-6680-UR-111	Electric	12.30	44.67
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	12/09/2002	D-6680-UR-111	Natural Gas	12.30	44.67
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	29/04/1997	D-6680-UR-110	Electric	11.70	52.00
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	29/04/1997	D-6680-UR-110	Natural Gas	11.70	52.00
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	08/12/1994	D-6680-UR-109	Electric	11.50	51.93
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	08/12/1994	D-6680-UR-109	Natural Gas	11.50	51.93
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	30/09/1993	D-6680-UR-108	Electric	11.60	50.31
Alliant Energy Corp.	Wisconsin Power and Light Co.	WI	30/09/1993	D-6680-UR-108	Natural Gas	11.60	50.31
Atmos Energy Corp.	Atmos Energy Corp.	GA	31/03/2010	D-30442	Natural Gas	10.70	47.70
Atmos Energy Corp.	Atmos Energy Corp.	GA	19/09/2008	D-27163-U	Natural Gas	10.70	45.00
Atmos Energy Corp.	Atmos Energy Corp.	GA	20/12/2005	D-20298-U	Natural Gas	10.13	45.00
Atmos Energy Corp.	Atmos Energy Corp.	KS	12/01/1993	D-181, 940-U	Natural Gas	10.64	12.00
Atmos Energy Corp.	Atmos Energy Corp.	LA	17/04/1996	D-U-21484	Natural Gas	10.77	53.25
Atmos Energy Corp.	Atmos Energy Corp.	TN	09/03/2009	D-08-00197	Natural Gas	10.30	48.12
Atmos Energy Corp.	Atmos Energy Corp.	TN	08/10/2007	D-07-00105	Natural Gas	10.48	44.20
Atmos Energy Corp.	Atmos Energy Corp.	TX	26/01/2010	D-GUD 9869	Natural Gas	10.40	48.91
Atmos Energy Corp.	Atmos Energy Corp.	TX	24/06/2008	D-GUD-9762	Natural Gas	10.00	48.27

Regulatory Decisions 1993-2012

Corporate Name	Subsidiary	State	Date of Decision	Docket Number	Type	ROE Allowed	Common Equity Ratio Allowed
Atmos Energy Corp.	Atmos Energy Corp.	TX	29/03/2007	D-GUD-9670	Natural Gas	10.00	48.10
Atmos Energy Corp.	Atmos Energy Corp.	TX	25/05/2004	D-GUD-9400	Natural Gas	10.00	49.80
Consolidated Edison	Consolidated Edison Co. of NY	NY	16/09/2010	C-09-G-0795	Natural Gas	9.60	48.00
Consolidated Edison	Consolidated Edison Co. of NY	NY	25/03/2010	C09-E-0428	Electric	10.15	48.00
Consolidated Edison	Consolidated Edison Co. of NY	NY	24/04/2009	C-08-E-0539	Electric	10.00	48.00
Consolidated Edison	Consolidated Edison Co. of NY	NY	25/03/2008	C-07-E-0523	Electric	9.10	47.98
Consolidated Edison	Consolidated Edison Co. of NY	NY	25/09/2007	C-06-G-1332	Natural Gas	9.70	48.00
Consolidated Edison	Consolidated Edison Co. of NY	NY	24/03/2005	C-04-E-0572	Electric	10.30	48.00
Consolidated Edison	Consolidated Edison Co. of NY	NY	27/09/2004	C-03-G-1671	Natural Gas	10.30	48.00
Consolidated Edison	Consolidated Edison Co. of NY	NY	17/04/2002	C-00-G-1456	Natural Gas	11.50	NA
Consolidated Edison	Consolidated Edison Co. of NY	NY	06/04/1995	C-94-E-0344	Electric	11.10	52.00
Consolidated Edison	Consolidated Edison Co. of NY	NY	29/09/1994	C-93-G-0996	Natural Gas	10.90	52.00
Consolidated Edison	Orange & Rockland Utilities Inc.	NY	14/06/2012	C-11-E-0408	Electric	9.40	48.00
Consolidated Edison	Orange & Rockland Utilities Inc.	NY	16/06/2011	C-10-E-0362	Electric	9.20	48.00
Consolidated Edison	Orange & Rockland Utilities Inc.	NY	16/10/2009	C-08-G-1398	Natural Gas	10.40	48.00
Consolidated Edison	Orange & Rockland Utilities Inc.	NY	16/07/2008	C-07-E-0949	Electric	9.40	48.00
Consolidated Edison	Orange & Rockland Utilities Inc.	NY	17/10/2007	C-06-E-1433	Electric	9.10	47.54
Consolidated Edison	Orange & Rockland Utilities Inc.	NY	20/10/2006	C-05-G-1494	Natural Gas	9.80	48.00
Consolidated Edison	Orange & Rockland Utilities Inc.	NY	12/08/1996	C-95E-0491, 93-M-0849	Electric	10.40	46.99
Consolidated Edison	Rockland Electric Co.	NJ	12/05/2010	D-ER-09080668	Electric	10.30	49.85
Consolidated Edison	Rockland Electric Co.	NJ	22/03/2007	D-ER-06060483	Electric	9.75	46.51
Consolidated Edison	Rockland Electric Co.	NJ	16/07/2003	D-ER-02100724	Electric	9.75	46.00
Integrys Energy Group Inc.	Michigan Gas Utilities Corp.	MI	16/12/2009	C-U-15990	Natural Gas	10.75	47.27
Integrys Energy Group Inc.	Michigan Gas Utilities Corp.	MI	13/01/2009	C-U-15549	Natural Gas	10.45	46.49
Integrys Energy Group Inc.	Michigan Gas Utilities Corp.	MI	12/03/2003	C-U-13470	Natural Gas	11.40	NA
Integrys Energy Group Inc.	Michigan Gas Utilities Corp.	MI	27/03/1997	C-U-10960	Natural Gas	10.75	42.44
Integrys Energy Group Inc.	Minnesota Energy Resources	MN	5/24/2012	D-G-007,011/GR-10-977	Natural Gas	9.70	50.48
Integrys Energy Group Inc.	Minnesota Energy Resources	MN	6/29/2009	D-G-007,011/GR-08-835	Natural Gas	10.21	48.77
Integrys Energy Group Inc.	Minnesota Energy Resources	MN	7/29/2003	D-G-007,011-GR-00-951	Natural Gas	11.71	49.99
Integrys Energy Group Inc.	Minnesota Energy Resources	MN	2/22/1993	D-G-011-GR-92-132	Natural Gas	11.60	50.66
Integrys Energy Group Inc.	North Shore Gas Co.	IL	10/01/2012	D-11-0280	Natural Gas	9.45	50.00
Integrys Energy Group Inc.	North Shore Gas Co.	IL	21/01/2010	D-09-0166	Natural Gas	10.33	56.00
Integrys Energy Group Inc.	North Shore Gas Co.	IL	05/02/2008	D-07-0241	Natural Gas	9.99	56.00
Integrys Energy Group Inc.	North Shore Gas Co.	IL	08/11/1995	D-95-0031	Natural Gas	11.30	57.04
Integrys Energy Group Inc.	Peoples Gas Light & Coke Co.	IL	10/01/2012	D-11-0281	Natural Gas	9.45	49.00
Integrys Energy Group Inc.	Peoples Gas Light & Coke Co.	IL	21/01/2010	D-09-0167	Natural Gas	10.23	56.00
Integrys Energy Group Inc.	Peoples Gas Light & Coke Co.	IL	05/02/2008	D-07-0242	Natural Gas	10.19	56.00
Integrys Energy Group Inc.	Peoples Gas Light & Coke Co.	IL	08/11/1995	D-95-0032	Natural Gas	11.10	51.08
Integrys Energy Group Inc.	Upper Peninsula Power Co.	MI	20/12/2011	C-U-16417	Electric	10.20	45.74
Integrys Energy Group Inc.	Upper Peninsula Power Co.	MI	21/12/2010	C-U-16166	Electric	10.30	50.42
Integrys Energy Group Inc.	Upper Peninsula Power Co.	MI	16/12/2009	C-U-15988	Electric	10.90	49.52
Integrys Energy Group Inc.	Upper Peninsula Power Co.	MI	27/06/2006	C-U-14745	Electric	10.75	47.12
Integrys Energy Group Inc.	Upper Peninsula Power Co.	MI	20/12/2002	C-U-13497	Electric	11.40	NA
Integrys Energy Group Inc.	Upper Peninsula Power Co.	MI	11/05/1993	C-U-10094	Electric	11.75	38.89
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	1/13/2011	D-6690-UR-120 (elec)	Electric	10.30	51.65
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	1/13/2011	D-6690-UR-120 (gas)	Natural Gas	10.30	51.65
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/30/2008	D-6690-UR-119 (elec)	Electric	NA	53.41
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/30/2008	D-6690-UR-119 (gas)	Natural Gas	NA	53.41
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	1/11/2007	D.6690-UR-118 (elec.)	Electric	10.90	57.46
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	1/11/2007	D.6690-UR-118 (gas)	Natural Gas	10.90	57.46
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/22/2005	D-6690-UR-117 (elec.)	Electric	11.00	59.73
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/22/2005	D-6690-UR-117 (gas)	Natural Gas	11.00	59.73
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/21/2004	D-6690-UR-116 (elec)	Electric	11.50	57.35
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/21/2004	D-6690-UR-116 (gas)	Natural Gas	11.50	57.35
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/19/2003	D-6690-UR-115 (elec)	Electric	12.00	56.00
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/19/2003	D-6690-UR-115 (gas)	Natural Gas	12.00	56.00
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	3/20/2003	D-6690-UR-114 (elec)	Electric	12.00	55.00
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	3/20/2003	D-6690-UR-114 (gas)	Natural Gas	12.00	55.00
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	6/20/2002	D-6690-UR-113 (elec.)	Electric	12.30	54.99
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	6/20/2002	D-6690-UR-113 (gas)	Natural Gas	12.30	54.99
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	11/30/2000	D-6690-UR-112 (elec.)	Electric	12.10	54.28
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	11/30/2000	D-6690-UR-112 (gas)	Natural Gas	12.10	54.28
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/17/1998	D-6690-UR-111 (elec.)	Electric	12.10	54.22
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/17/1998	D-6690-UR-111 (gas)	Natural Gas	12.10	54.22
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	2/20/1997	D-6690-UR-110 (elec)	Electric	11.80	54.80
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	2/20/1997	D-6690-UR-110 (gas)	Natural Gas	11.80	54.80
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/19/1994	D-6690-UR-109 (elec)	Electric	11.50	55.43
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/19/1994	D-6690-UR-109 (gas)	Natural Gas	11.50	55.43

Regulatory Decisions 1993-2012

Corporate Name	Subsidiary	State	Date of Decision	Docket Number	Type	ROE Allowed	Common Equity Ratio Allowed
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/21/1993	D-6690-UR-108 (elec)	Electric	11.30	55.61
Integrys Energy Group Inc.	Wisconsin Public Service Corp.	WI	12/21/1993	D-6690-UR-108 (gas)	Natural Gas	11.30	55.61
Northwest Natural Gas	Northwest Natural Gas Co.	OR	8/22/2003	D-UG-152	Natural Gas	10.20	49.50
Northwest Natural Gas	Northwest Natural Gas Co.	OR	11/12/1999	D-UG-132	Natural Gas	10.25	47.71
Northwest Natural Gas	Northwest Natural Gas Co.	WA	12/26/2008	D-UG-08-0546	Natural Gas	10.10	50.74
Piedmont Natural Gas	Piedmont Natural Gas Co.	NC	10/24/2008	D-G-9, Sub 550	Natural Gas	10.60	51.00
Piedmont Natural Gas	Piedmont Natural Gas Co.	NC	10/28/2002	D-G-9,SUB461	Natural Gas	11.30	52.66
Piedmont Natural Gas	Piedmont Natural Gas Co.	NC	10/5/2000	D-G-9, SUB 428	Natural Gas	11.30	52.71
Piedmont Natural Gas	Piedmont Natural Gas Co.	SC	11/1/2002	D-2002-63-G	Natural Gas	12.60	54.90
Piedmont Natural Gas	Piedmont Natural Gas Co.	SC	11/7/1995	D-95-715-G	Natural Gas	12.50	54.19
Piedmont Natural Gas	Piedmont Natural Gas Co.	TN	1/23/2012	D-11-00144	Natural Gas	10.20	52.71
Piedmont Natural Gas	Piedmont Natural Gas Co.	TN	12/17/1996	D-96-00977	Natural Gas	11.50	49.60
Southern Company	Georgia Power Co.	GA	12/29/2010	D-31958	Electric	11.15	NA
Southern Company	Georgia Power Co.	GA	12/31/2007	D-25060-U	Electric	11.25	NA
Southern Company	Georgia Power Co.	GA	12/21/2004	D-18300-U	Electric	11.25	NA
Southern Company	Georgia Power Co.	GA	12/20/2001	D-14000-U	Electric	12.50	51.67
Southern Company	Gulf Power Co.	FL	2/27/2012	D-110138-EI	Electric	10.25	38.50
Southern Company	Gulf Power Co.	FL	6/10/2002	D-010949-EI	Electric	12.00	41.02
Southern Company	Mississippi Power Co.	MS	12/3/2001	D-01-UN-0548	Electric	12.88	53.68
Southern Company	Mississippi Power Co.	MS	1/4/1994	C-93-UA-0302	Electric	10.07	NA
Southern Company	Savannah Electric & Power Co.	GA	5/25/2005	D-19758-U	Electric	10.75	NA
Vectren Corp.	Indiana Gas Co.	IN	2/13/2008	Ca-43298	Natural Gas	10.20	48.99
Vectren Corp.	Indiana Gas Co.	IN	11/30/2004	Ca-42598	Natural Gas	10.60	50.06
Vectren Corp.	Southern Indiana Gas & Elec Co	IN	4/27/2011	Ca-43839	Electric	10.40	43.46
Vectren Corp.	Southern Indiana Gas & Elec Co	IN	8/15/2007	Ca-43111	Electric	10.40	47.05
Vectren Corp.	Southern Indiana Gas & Elec Co	IN	8/1/2007	Ca-43112	Natural Gas	10.15	47.05
Vectren Corp.	Southern Indiana Gas & Elec Co	IN	6/30/2004	Ca-42596	Natural Gas	10.50	44.00
Vectren Corp.	Southern Indiana Gas & Elec Co	IN	7/3/1996	Ca-40283	Natural Gas	11.25	38.38
Vectren Corp.	Southern Indiana Gas & Elec Co	IN	6/21/1995	Ca-39871	Electric	12.25	36.60
Vectren Corp.	Southern Indiana Gas & Elec Co	IN	7/21/1993	Ca-39539	Natural Gas	11.90	38.70
Vectren Corp.	Vectren Energy Delivery Ohio	OH	4/13/2005	C-04-571-GA-AIR	Natural Gas	10.60	48.10
WGL Holdings Inc.	Washington Gas Light Co.	DC	11/10/2003	FC-1016	Natural Gas	10.60	50.30
WGL Holdings Inc.	Washington Gas Light Co.	DC	10/30/2002	FC-989	Natural Gas	10.60	54.00
WGL Holdings Inc.	Washington Gas Light Co.	DC	10/8/1993	FC-922	Natural Gas	11.50	54.00
WGL Holdings Inc.	Washington Gas Light Co.	MD	11/14/2011	C-9267	Natural Gas	9.60	57.88
WGL Holdings Inc.	Washington Gas Light Co.	MD	11/15/2007	C-9104	Natural Gas	10.00	53.02
WGL Holdings Inc.	Washington Gas Light Co.	MD	10/31/2003	C-8959	Natural Gas	10.75	51.49
WGL Holdings Inc.	Washington Gas Light Co.	MD	10/18/1994	C-8660	Natural Gas	11.50	54.90
WGL Holdings Inc.	Washington Gas Light Co.	MD	7/29/1993	C-8545	Natural Gas	11.50	54.00
WGL Holdings Inc.	Washington Gas Light Co.	VA	7/2/2012	C-PUE-2010-00139	Natural Gas	9.75	59.63
WGL Holdings Inc.	Washington Gas Light Co.	VA	4/21/2011	C-PUE-2010-00087	Natural Gas	10.00	55.70
WGL Holdings Inc.	Washington Gas Light Co.	VA	9/19/2007	C-PUE-2006-00059	Natural Gas	10.00	NA
WGL Holdings Inc.	Washington Gas Light Co.	VA	9/27/2004	C-PUE-2003-00603	Natural Gas	10.50	50.96
WGL Holdings Inc.	Washington Gas Light Co.	VA	12/18/2003	C-PUE-2002-00364	Natural Gas	10.50	50.96
WGL Holdings Inc.	Washington Gas Light Co.	VA	9/29/1995	C-PUE-940031	Natural Gas	11.50	51.61
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	MI	6/26/2012	C-U-16830	Electric	10.10	43.51
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	MI	7/1/2010	C-U-15981	Electric	10.25	47.61
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	MI	11/13/2008	C-U-15500	Electric	10.55	NA
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	12/18/2009	D-5-UR-104 (WEP-EL)	Electric	10.40	53.02
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	12/18/2009	D-5-UR-104 (WEP-GAS)	Natural Gas	10.40	53.02
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	1/17/2008	D-5-UR-103 (WEP-EL)	Electric	10.75	54.36
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	1/17/2008	D-5-UR-103 (WEP-GAS)	Natural Gas	10.75	54.36
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	1/25/2006	D-05-UR-102 (WEP-GAS)	Natural Gas	11.20	56.34
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	7/20/2000	D-6630-UR-111 (gas)	Natural Gas	12.20	53.45
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	7/18/2000	D-6630-UR-111 (elec.)	Electric	12.20	53.45
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	4/30/1998	D-6630-UR-110 (elec.)	Electric	12.20	53.14
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	4/30/1998	D-6630-UR-110 (gas)	Natural Gas	12.20	53.14
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	2/13/1997	D-6630-UR-109 (elec)	Electric	11.80	53.35
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	9/11/1995	D-6630-UR-108	Electric	11.30	53.96
Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	2/15/1993	D-6630-UR-106	Electric	12.30	51.19
Wisconsin Energy Corp.	Wisconsin Gas LLC	WI	12/18/2009	D-5-UR-104 (WG)	Natural Gas	10.50	46.62
Wisconsin Energy Corp.	Wisconsin Gas LLC	WI	1/17/2008	D-5-UR-103 (WG)	Natural Gas	10.75	46.64
Wisconsin Energy Corp.	Wisconsin Gas LLC	WI	1/25/2006	D-05-UR-102 (WG)	Natural Gas	11.20	50.20
Wisconsin Energy Corp.	Wisconsin Gas LLC	WI	11/12/1993	D-6650-GR-111	Natural Gas	11.80	48.43
Xcel Energy Inc.	Northern States Power Co - WI	WI	12/22/2011	D-4220-UR-117 (elec)	Electric	10.40	52.59
Xcel Energy Inc.	Northern States Power Co - WI	WI	12/22/2011	D-4220-UR-117 (gas)	Natural Gas	10.40	52.59
Xcel Energy Inc.	Northern States Power Co - WI	WI	12/22/2009	D-4220-UR-116 (elec)	Electric	10.40	52.30
Xcel Energy Inc.	Northern States Power Co - WI	WI	1/8/2008	D-4220-UR-115 (elec)	Electric	10.75	52.51

Regulatory Decisions 1993-2012

Corporate Name	Subsidiary	State	Date of Decision	Docket Number	Type	ROE Allowed	Common Equity Ratio Allowed
Xcel Energy Inc.	Northern States Power Co - WI	WI	1/8/2008	D-4220-UR-115 (gas)	Natural Gas	10.75	52.51
Xcel Energy Inc.	Northern States Power Co - WI	WI	1/5/2006	D-4220-UR-114 (elec.)	Electric	11.00	53.66
Xcel Energy Inc.	Northern States Power Co - WI	WI	1/5/2006	D-4220-UR-114 (gas)	Natural Gas	11.00	53.66
Xcel Energy Inc.	Northern States Power Co - WI	WI	9/15/1998	D-4220-UR-110 (elec.)	Electric	11.90	55.00
Xcel Energy Inc.	Northern States Power Co - WI	WI	9/15/1998	D-4220-UR-110 (gas)	Natural Gas	11.90	55.00
Xcel Energy Inc.	Northern States Power Co - WI	WI	11/26/1996	D-4220-UR-109 (elec)	Electric	11.30	55.00
Xcel Energy Inc.	Northern States Power Co - WI	WI	11/26/1996	D-4220-UR-109 (gas)	Natural Gas	11.30	55.00
Xcel Energy Inc.	Northern States Power Co - WI	WI	12/14/1995	D-4220-UR-108 (gas)	Natural Gas	11.30	54.99
Xcel Energy Inc.	Northern States Power Co - WI	WI	9/27/1995	D-4220-UR-108 (elec)	Electric	11.30	54.99
Xcel Energy Inc.	Northern States Power Co - WI	WI	1/12/1993	D-4220-UR-106 (elec)	Electric	12.00	56.94
Xcel Energy Inc.	Northern States Power Co - WI	WI	1/12/1993	D-4220-UR-106 (gas)	Natural Gas	12.00	56.94
Xcel Energy Inc.	Northern States Power Co. - MN	MN	3/29/2012	D-E-002/GR-10-971	Electric	10.37	52.56
Xcel Energy Inc.	Northern States Power Co. - MN	MN	12/6/2010	D-G-002/GR-09-1153	Natural Gas	10.09	52.46
Xcel Energy Inc.	Northern States Power Co. - MN	MN	10/23/2009	D-E-002/GR-08-1065	Electric	10.88	52.47
Xcel Energy Inc.	Northern States Power Co. - MN	MN	9/10/2007	D-G-002-GR-06-1429	Natural Gas	9.71	51.98
Xcel Energy Inc.	Northern States Power Co. - MN	MN	9/1/2006	D-E-002-GR-05-1428	Electric	10.54	51.67
Xcel Energy Inc.	Northern States Power Co. - MN	MN	8/11/2005	D-G-002-GR-04-1511	Natural Gas	10.40	50.24
Xcel Energy Inc.	Northern States Power Co. - MN	MN	9/3/1998	D-G-002-GR-97-1606	Natural Gas	11.40	45.86
Xcel Energy Inc.	Northern States Power Co. - MN	MN	9/29/1993	D-E-002-GR-92-1185	Electric	11.47	48.39
Xcel Energy Inc.	Northern States Power Co. - MN	MN	9/1/1993	D-G-002-GR-92-1186	Natural Gas	11.47	48.39
Xcel Energy Inc.	Northern States Power Co. - MN	ND	2/29/2012	C-PU-10-657	Electric	10.40	NA
Xcel Energy Inc.	Northern States Power Co. - MN	ND	12/31/2008	C-PU-07-776	Electric	10.75	51.77
Xcel Energy Inc.	Northern States Power Co. - MN	ND	6/13/2007	C-PU-06-525	Natural Gas	10.75	51.59
Xcel Energy Inc.	Northern States Power Co. - MN	SD	6/19/2012	D-EL11-019	Electric	9.25	53.04
Xcel Energy Inc.	Public Service Co. of CO	CO	4/26/2012	D-11AL-947E	Electric	10.00	56.00
Xcel Energy Inc.	Public Service Co. of CO	CO	9/1/2011	D-10AL-963G	Natural Gas	10.10	56.00
Xcel Energy Inc.	Public Service Co. of CO	CO	12/3/2009	D-09AL-299E	Electric	10.50	58.56
Xcel Energy Inc.	Public Service Co. of CO	CO	7/3/2007	D-06S-656G	Natural Gas	10.25	60.17
Xcel Energy Inc.	Public Service Co. of CO	CO	12/1/2006	D-06S-234EG	Electric	10.50	60.00
Xcel Energy Inc.	Public Service Co. of CO	CO	2/3/2006	D-05S-264G	Natural Gas	10.50	55.49
Xcel Energy Inc.	Public Service Co. of CO	CO	6/26/2003	D-02S-315E	Electric	10.75	51.40
Xcel Energy Inc.	Public Service Co. of CO	CO	6/26/2003	D-02S-315G	Natural Gas	11.00	51.40
Xcel Energy Inc.	Public Service Co. of CO	CO	3/15/2001	D-00S-422G	Natural Gas	11.25	50.40
Xcel Energy Inc.	Public Service Co. of CO	CO	6/8/1999	D-98S-518G	Natural Gas	11.25	52.36
Xcel Energy Inc.	Public Service Co. of CO	CO	1/31/1997	D-96S-290G	Natural Gas	11.25	52.79
Xcel Energy Inc.	Public Service Co. of CO	CO	11/26/1993	D-93S-001E	Electric	11.00	44.62
Xcel Energy Inc.	Public Service Co. of CO	CO	11/26/1993	D-93S-001G	Natural Gas	11.00	44.62
Xcel Energy Inc.	Southwestern Public Service Co	NM	8/26/2008	C-07-00319-UT	Electric	10.18	51.23

Source: Regulatory Research Associates

S&P Credit Ratings

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
AGL RESOURCES INC	BBB+	BBB+	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-	BBB+
ALLIANT ENERGY CORP	NA	A+	A+	A-	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
ATMOS ENERGY CORP	A-	A-	A-	A-	A-	A-	BBB	BBB	BBB	BBB	BBB+	BBB+	BBB+	BBB+
CONSOLIDATED EDISON INC	NA	A	A	A	A+	A	A	A	A	A	A-	A-	A-	A-
INTEGRYS ENERGY GROUP INC	NA	NA	NA	NA	A	A	A	A	A	A-	A-	BBB+	BBB+	BBB+
NORTHWEST NATURAL GAS CO	A	A	A	A	A	A	A	A+	AA-	AA-	AA-	AA-	A+	A+
PIEDMONT NATURAL GAS CO	A	A	A	A	A	A	A	A	A	A	A	A	A	A
SOUTHERN CO	A	A	A	A	A	A	A	A	A	A	A	A	A	A
VECTREN CORP	A+	A+	A	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-	A-
WGL HOLDINGS INC	NA	NA	AA-	AA-	AA-	AA-	AA-	AA-	AA-	AA-	AA-	AA-	AA-	A+
WISCONSIN ENERGY CORP	NA	AA	A+	A-	A-	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	A-
XCEL ENERGY INC	NA	NA	A-	A-	BBB	BBB	BBB	BBB	BBB	BBB+	BBB+	BBB+	A-	A-

Moody's Credit Ratings [1/]

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
AGL RESOURCES INC	Baa1	Baa1	Baa2	Baa2	Baa2	Baa2	Baa2	Baa2	Baa2	Baa2	Baa2	Baa2	Baa2	Baa2
ALLIANT ENERGY CORP	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Baa1	Baa1
ATMOS ENERGY CORP	A3	A3	A3	A3	A3	A3	Baa3	Baa3	Baa3	Baa3	Baa3	Baa3	Baa2	Baa1
CONSOLIDATED EDISON INC	NA	NA	NA	NA	A2	A2	A2	A2	A2	A2	A2	Baa1	Baa1	Baa1
INTEGRYS ENERGY GROUP INC	NA	Aa3	Aa3	Aa3	Aa3	Aa3	A1	A1	A1	A3	A3	Baa1	Baa1	Baa1
NORTHWEST NATURAL GAS CO	A3	A3	A3	A3	A3	A3	A3	A3	A3	A3	A3	A3	A3	A3
PIEDMONT NATURAL GAS CO	A2	A2	A2	A2	A2	A3	A3	A3	A3	A3	A3	A3	A3	A3
SOUTHERN CO	NA	NA	NA	NA	NA	NA	NA	NA	NA	A3	A3	A3	Baa1	Baa1
VECTREN CORP	NA	NA	A3	A2	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1	A3	A3
WGL HOLDINGS INC	Aa3	Aa2	Aa2	Aa2	A2	A2	A2	A2	A2	A2	A2	A2	A2	A2
WISCONSIN ENERGY CORP	NA	NA	A1	A2	A2	A3	A3	A3	A3	A3	A3	A3	A3	A3
XCEL ENERGY INC	NA	NA	A3	A3	Baa3	Baa3	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1

[1/] Ratings for Vectren Corp. is for Vectren Utility Holdings. Rating for WGL Holdings is Washington Gas Light.

Attachment 54.2

Regulatory Method	Typical Canadian Practice	Typical U.S. Practice	Impact on Regulatory Lag, Attrition, Business Risk
Test Year	Forward	Mix of Forecast, Partial Forecast, Historic adjusted for known and measurable changes	All other things equal, historic test year entails most regulatory lag and potential for attrition
Revenue Decoupling & Adjustment for Average Customer Use [1/]	Implemented for some utilities	Widespread use	Reduces regulatory lag and attrition, as accounts for declining average customer use
Weather Normalization	Implemented for some utilities	Widespread use	No impact on regulatory lag or attrition, but reduces variability of earnings
Rate Stabilization Mechanism (Automatic Rate Adjustment)	Not used	Implemented in several states	Mechanism adjusts rates to achieve ROE in allowed range; reduces regulatory lag and attrition
Flat Monthly Fee Rate Design	Used predominantly by pipelines	Implemented in a number of states for gas	Provides higher assurance of recovery of fixed costs than rates with significant portion of fixed costs recovered in variable rate
Rate Trackers for Gas Costs	Used by all gas utilities who sell gas	Used by virtually all gas utilities who sell gas	Reduces regulatory lag, as provides for timely recovery of actual gas costs
Variance Accounts for Fuel Costs/Purchased Power	Predominant practice for investor-owned electric utilities who generate electricity and/or purchase power	Predominant practice for investor-owned electric utilities who generate electricity and/or purchase power	Reduces regulatory lag, as provides for timely recovery of actual fuel and purchased power costs
Rate Trackers for Bad Debt Costs/Deferral Accounts for Lost Margin	Implemented for some utilities	Widespread use	Reduces regulatory lag
New Infrastructure Cost Tracker	Not used	Widespread for gas utilities	Reduces regulatory lag and potential for attrition, as provides for timely rate base treatment of capital expenditures
CWIP in Rate Base	Has been used in limited circumstances	Allowed for many gas utilities where facilities to be in rate base within next year, for many electric utilities for large scale and environmental compliance projects and for inter-state electric transmission by FERC	Reduces regulatory lag as allows cash returns earlier than AFUDC
Tracker/Regulatory Assurance of Pension/OPEB Expense Recovery	Trackers allowed for a few utilities; all have regulatory asset for pension/OPEB	Trackers allowed for some utilities; all have regulatory asset for pension/OPEB	Tracker reduces regulatory lag; timely recovery of actual pension expense. Regulatory asset for pension/OPEB indicates regulatory assurance costs are recoverable in rates

Regulatory Method	Typical Canadian Practice	Typical U.S. Practice	Impact on Regulatory Lag, Attrition, Business Risk
Frequency of Revenue Requirements Applications	Variable depending on jurisdiction and form of regulation (PBR versus cost of service). Annual to five-year interval	Overall, less frequent than in Canada, but wide variation. Except where rate freeze agreed to, can file at utility's option. Frequency has increased in past five years	All other things equal, more frequent rate cases reduce regulatory lag and potential attrition.
Frequency of Capital Structure/ROE applications	Wide variation, ranging from annual/bi-annual to five year intervals	Same frequency as revenue requirements applications	Indeterminate relative impact, as widespread use of formula approach to ROE in Canada produced high sensitivity of ROEs to interest rates and relatively low ROEs
Plant Accounts	Mid-year of forecast test year	Depends on type of test year. Most historic test years use end of year balances, adjusted for known and measurable changes	Generally, impacts similar to test year. The use of test year-end plant balances, with adjustments for known and measurable changes, where a historic test year is used, reduces regulatory lag and potential for attrition relative to mid-year or beginning of test year values
Interim Rates	Widely allowed	Widely allowed	Reduces regulatory lag
Expense Adjustments	N/A, as Canadian utilities operate with forward test years	N/A for forward test years; for historic test years, adjustments typically made for known and measurable changes	For historic test years, adjustments to incurred costs for known and measurable changes reduces regulatory lag
Deferral Accounts	Widespread use	Widespread use	Deferral Accounts generally provide better assurance that costs incurred will be recoverable from customers. Deferral accounts reduce the potential for attrition.
Income Tax Methodology	Predominantly income taxes payable	Predominantly normalized/future income tax methodology	Future income tax approach provides growing utilities better cash flow than the income taxes payable and better assurance that, when the taxes actually come due, there is less risk that they will need to be recovered from the then available customer base.

[1/] Includes partial decoupling for demand side management effects only. The term "conservation savings adjustment", which appears in the WUTC decision (Exhibit A2-16), and referenced in the question, was a company-specific proposed revenue decoupling mechanism.

Note: The term "equity share (thickness) upward adjustment for attrition", which appears in the WUTC decision (Exhibit A2-16), is not a practice that Ms. McShane has seen discussed elsewhere.

Attachment 73.2

	Moody's		S&P	
	Issuer Rating	**Debt Rating**	**Corporate Credit**	**Debt Rating**
AGL Resources Inc.		Baa1 (Senior Unsecured Shelf)	BBB+	BBB+ (Senior Unsecured)
Atlanta Gas Light		A3 (Senior Unsecured)	BBB+	BBB+ (Senior Unsecured)
Nicor (Northern Illinois) Gas	A3	A1 (First Mortgage)	BBB+	A (Senior Secured)
Pivotal Utility Holdings			BBB+	
Alliant Energy Corp.	Baa1	Baa1 (Senior Unsecured)	BBB+	BBB (Senior Unsecured)
Interstate Power and Light	A3	A3 (Senior Unsecured)	BBB+	BBB+ (Senior Unsecured)
Wisconsin Power and Light	A2	A2 (Senior Unsecured)	A-	A- (Senior Unsecured)
Atmos Energy Corp.		Baa1 (Senior Unsecured)	BBB+	BBB+ (Senior Unsecured)
Consolidated Edison	Baa1	Baa1 (Senior Unsecured Shelf)	A-	
ConEd of New York	A3	A3 (Senior Unsecured)	A-	A- (Senior Unsecured)
Orange & Rockland	Baa1	Baa1 (Senior Unsecured)	A-	A- (Senior Unsecured)
Rockland Electric			A-	
Integrys Energy Group Inc.		Baa1 (Senior Unsecured)	A-	
North Shore Gas	A3	A1 (First Mortgage)	A-	A (Senior Secured)
Peoples Gas Light & Coke	A3	A1 (First Mortgage)	A-	A- (Senior Secured)
Wisconsin Public Service Corp.	A2	Aa3 (Senior Secured)	A-	A (Senior Secured)
Northwest Natural Gas		A3 (Senior Unsecured)	A+	A+ (Senior Unsecured)
Piedmont Natural Gas		A3 (Senior Unsecured)	A	A (Senior Secured)
Southern Company		Baa1 (Senior Unsecured)	A	A- (Senior Unsecured)
Alabama Power Company	A2	A2 (Senior Unsecured)	A	A (Senior Unsecured)
Georgia Power	A3	A3 (Senior Unsecured)	A	A (Senior Unsecured)
Gulf Power	A3	A3 (Senior Unsecured)	A	A (Senior Unsecured)
Mississippi Power	A3	A3 (Senior Unsecured)	A	A (Senior Unsecured)
Savannah Electric & Power		A3 (Backed Senior Unsecured)		
Southern Elec. Generating	A2	A2 (Backed Senior Unsecured)	A	A (Senior Unsecured)
Southern Power	Baa1	Baa1 (Senior Unsecured)	BBB+	BBB+ (Senior Unsecured)
Vectren Corp.			A-	
Indiana Gas Co		A3 (Senior Unsecured)	A-	A- (Senior Unsecured)
Southern Indiana Gas & Electric	A3	A1 (Senior Secured)	A-	A- (Senior Unsecured)
Vectren Utility Holdings		A3 (Senior Unsecured)	A-	A- (Senior Unsecured)
WGL Holdings Inc.			A+	
Washington Gas Light		A2 (Senior Unsecured)	A+	A+ (Senior Unsecured)
Wisconsin Energy Corp.	A3	A3 (Senior Unsecured)	A-	
Wisconsin Electric Power	A2	A2 (Senior Unsecured)	A-	A- (Senior Unsecured)
Wisconsin Gas		A2 (Senior Unsecured)	A-	A- (Senior Unsecured)
Xcel Energy Inc.	Baa1	Baa1 (Senior Unsecured)	A-	BBB+(Senior Unsecured)
Northern States Power (MN)	A3	A3 (Senior Unsecured Shelf)	A-	
Northern States Power (WI)		A3 (Senior Unsecured Shelf)	A-	A (Senior Secured)
Public Service Co. of Colorado	Baa1	Baa1 (Senior Unsecured Shelf)	A-	A (Senior Secured)
Southwestern Public Service Co.	Baa1	Baa1 (Senior Unsecured)	A-	A- (Senior Unsecured)

Source: www.dbrs.com, www.moodys.com, Standard and Poor's

DEBT RATINGS OF SAMPLE OF CANADIAN UTILITIES USED TO ESTIMATE DCF COSTS OF EQUITY
INCLUDING RATINGS OF REGULATED SUBSIDIARIES

	DBRS		Moody's		S&P	
Company/Regulated Sub	**Issuer Rating**	**Debt Rating**	**Issuer Rating**	**Debt Rating**	**Corporate Credit Rating**	**Debt Rating**
Canadian Utilities Limited		A			A	A (Senior Unsecured)
CU Inc.		A(high) (Unsecured)			A	A (Senior Unsecured)
ATCO Electric						
ATCO Gas						
ATCO Pipelines						
Emera Inc.		BBB(high) (Med. Term Notes)	1/	1/	BBB+	BBB+ (Senior Unsecured)
Nova Scotia Power		A(low) (Unsecured)	1/	1/	BBB+	BBB+ (Senior Unsecured)
Enbridge Inc.		A(low) (Unsecured)	Baa1	Baa1 (Senior Unsecured)	A-	A- (Senior Unsecured)
Enbridge Gas Distribution		A (Unsecured)			A-	A- (Senior Unsecured)
Enbridge Pipelines Inc.		A (Unsecured)			A-	A- (Senior Unsecured)
Fortis Inc.		A(low)			A-	
Caribbean Utilities Company		A(low) (Senior Notes)			A-	A- (Senior Unsecured)
FortisAlberta Inc.		A(low) (Senior Unsecured)		Baa1 (Senior Unsecured)	A-	A- (Senior Unsecured)
FortisBC Holdings Inc.		BBB(high) (Med. Term Debentures)		Baa2 (Senior Unsecured)		
FortisBC Energy Inc.		A (Unsecured)		A3 (Senior Unsecured)		2/
FortisBC Energy Inc. (VI)		BBB(high) (Debentures)		A3 (Senior Unsecured)		
FortisBC Inc.		A(low) (Unsecured)		Baa1 (Senior Unsecured)		
Maritime Electric					BBB+	A- (Senior Secured)
Newfoundland Power		A (First Mortgage)	Baa1	A2 (First Mortgage)		
TransCanada Corp			Baa1			
TransCanada PipeLines Ltd.		A (Unsecured)	A3	A3 (Senior Unsecured)	A-	A- (Senior Unsecured)
ANR Pipeline Co.				A3 (Senior Unsecured)	A-	A- (Senior Unsecured)
NOVA Gas Transmission Ltd.		A (Unsecured)		A3 (Senior Unsecured)	A-	A- (Senior Unsecured)
Gas Transmission Northwest LLC				A3 (Senior Unsecured)		
TC Pipelines LP				Baa2 (Senior Unsecured)		

1/ Ratings withdrawn at request of company March 2010; Emera and NSPI unsecured debt previously rated Baa2 and Baa1.
2/ S&P ratings affirmed at AA- for Senior Secured Debt and A for Unsecured Debt, then withdrawn September 23, 2010.

Source: www.dbrs.com, www.moodys.com, Standard and Poor's

Attachment 76.2

FILED CONFIDENTIALLY

Attachment 80.4

Decision **2004-052**

Generic Cost of Capital

AltaGas Utilities Inc.
AltaLink Management Ltd.
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
EPCOR Distribution Inc.
EPCOR Transmission Inc.
FortisAlberta (formerly Aquila Networks)
NOVA Gas Transmission Ltd.

July 2, 2004

Alberta Energy and Utilities Board

Table 13. Board Approved Equity Ratios

	Last Board-Approved Common Equity Ratios (%)	2004 Board Approved Common Equity Ratios (%)	Change in Approved Common Equity Ratio (%)
ATCO TFO	32.0	33.0	1.0
AltaLink	34.0[133]	35.0	1.0
EPCOR TFO	35.0	35.0	0.0
NGTL	32.0	35.0	3.0
ATCO Electric DISCO	35.0	37.0	2.0
FortisAlberta (Aquila)	N/A [134]	37.0	N/A
ATCO Gas	37.0	38.0	1.0
ENMAX DISCO	N/A [135]	39.0	N/A
EPCOR DISCO	N/A [125]	39.0	N/A
AltaGas	41.0	41.0	0.0
ATCO Pipelines	43.5	43.0	(0.5)

5.6 ATCO Utilities Preferred Shares

In earlier sections, the Board noted that the 2004 approved common equity ratios in this Decision for the ATCO utilities were not adjusted to reflect any impact of ATCO's use of preferred shares. The Board notes that there was essentially no evidence presented regarding the impact of preferred shares on the required common equity ratios.

The Board has recognized in previous decisions that during the period of time when income tax rebates were in place, it was prudent to utilize preferred share financing in place of debt.

However, the Board considers that there may be merit in further consideration of the appropriateness of the continuing use of preferred shares as a form of financing, to understand the redemption options and to fully explore the related implications and options.

The Board directs ATCO to address the appropriateness of the continuing use of preferred shares as a form of financing, in the next Phase 1 GRA/GTA for ATCO Gas, ATCO Pipelines or ATCO Electric, whichever comes first.

5.7 Process to Adjust Capital Structure

The Board notes that all parties, except for CG, considered that it would be appropriate to address any future changes in capital structure in utility-specific GRA/GTAs. CG proposed a scheduled review of the capital structures of all Applicants.

The Board agrees with the general consensus that it would be more appropriate to address any future changes in capital structure in utility-specific GRA/GTAs. The Board also agrees with the general consensus that such changes should only be pursued if parties perceive that there has

133 In Decision 2003-061, the Board approved an equity ratio for AltaLink of 32%, plus an additional 2% to offset the impact on the interest coverage ratio of a partial allowance of income taxes in the revenue requirement.

134 The Board did not specifically approve this ratio; it was part of a negotiated settlement approved in Decision 2003-019, which included a deemed 40% equity ratio as one of many settled parameters of the revenue requirement.

135 Both EPCOR and ENMAX Distribution were subject to Board jurisdiction effective January 1, 2004.

ATCO Utilities

2005-2007 Common Matters Application

October 11, 2006

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2006-100: ATCO Utilities
2005-2007 Common Matters Application
Application No. 1407946

October 11, 2006

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Contents

List of Tables

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

ATCO UTILITIES **Decision 2006-100**
2005-2007 COMMON MATTERS APPLICATION **Application No. 1407946**

1 INTRODUCTION

By letter dated June 30, 2006, ATCO Utilities filed an application (Application) with the Alberta Energy and Utilities Board (EUB or the Board) to address certain common matters for three of its utilities, ATCO Gas (North and South), ATCO Electric (transmission and distribution) and ATCO Pipelines (North and South) (collectively the ATCO Utilities or AU).

The Application seeks approval for common matters relating to:

- pension costs
- head office rent
- the use of preferred shares in capital structure; and
- executive compensation.

The above will be collectively referred to as the Common Matters.

The Board's notice of hearing was posted on the Board's web site and distributed by email on July 25th, 2005 to the parties on the ATCO Electric 2005-2006 GTA distribution list, the ATCO Pipelines 2004 GRA Phase II distribution list and the ATCO Gas 2005-2007 GRA distribution list.

By letter dated September 7th, 2005, the Board set out a process schedule for this proceeding which included an oral hearing commencing May 2, 2005. By letter dated March 31, 2006 the Board notified parties that the commencement of the hearing was changed to May 9, 2006 and that the issue of executive compensation would be heard on May 31, 2006.

The public hearing was convened in Calgary from May 9-11, 2006 with an additional day on May 31, 2006 before Board members Mr. B. T. McManus Q.C. (Chair), Mr. J. I. Douglas, FCA (Member), and Mr. M. L. Asgar-Deen, P.Eng (Acting Member).

In accordance with the schedule established by the Board, parties filed written argument and reply on June 21, 2006 and July 14, 2006, respectively. Accordingly, the Board considers that July 14, 2006, was the close of record for this proceeding.

Appendix 1 lists the parties who participated in the hearing.

2 BACKGROUND

In planning the 2005-2007 General Rate Application (GRA) (Application No. 1400690) for ATCO Gas (AG) and the General Tariff Application (GTA) (Application 1399997) for ATCO Electric (AE), the ATCO Utilities proposed that the Common Matters listed above would be addressed in a separate Common Matters application to be made jointly by the ATCO Utilities jointly. Placeholders for each of the Common Matters were inserted into the applied for revenue requirement for each of ATCO Gas and ATCO Electric. ATCO Pipelines had not filed a Phase I rate application for the 2005 test year.

In response to an undertaking to Board Counsel, AU revised Board Hearing Exhibit 30-006, and provided Exhibit 02-038 (ATCO Utilities Placeholder and Revenue Requirement Summary) clarifying both the existing revenue requirement placeholder amounts for each of the ATCO Utilities and the amounts applied for by AU in substitution for these placeholders. Exhibit 02-038 is provided as Appendix 2 to this Decision.

This Common Matters Application responds to directions made in the following Board Decisions:

Decision 2003-071 ATCO Electric 2003-2004 GTA, October 2, 2003;
Decision 2004-014 ATCO Electric 2003-2004 GTA Phase I Refiling, February 17, 2004;
Decision 2003-072 ATCO Gas 2003/04 GRA Phase I, October 1, 2003;
Decision 2003-100 ATCO Pipelines 2003/2004 GRA - Phase I, December 2, 2003;
Decision 2004-049 ATCO Utilities Review of ATCO Executive Compensation Allocated to the ATCO Utilities, June 24, 2004; and
Decision 2004-052 Generic Cost of Capital, July 2, 2004

3 PENSION AND POST EMPLOYMENT EXPENSE

AU is seeking to recover a deferred pension asset totaling $22.993 million (Deferred Pension Asset) over a period of nine years. During the recovery period AU seeks to continue to collect a return on this asset through its inclusion as necessary working capital or as a reduction to no-cost capital.

AU first identified the Deferred Pension Asset amounts, including the breakdown by utility, in its 2001 Pension Negotiated Settlement Agreement (Pension NSA), which the Board approved in Decision 2001-105.[1] In its evidence,[2] AU indicated that $2.564 million (Over-Funding Component) of the pension asset arose due to over-funding under accrual pension accounting. AU explained that in the period prior to the end of 1999 it had paid more cash into the pension plan than was charged for accounting purposes as a pension expense. AU indicated that the remaining $20.429 million (Restructuring Component) arose as a result of several corporate restructurings when many employees left the pension plan. The Board understands that when the employees left the pension plan, accounting rules required the creation of a deferred pension asset of $20.429 million to recognize the reduction in pension liabilities net of amounts transferred out of the pension plan with the departing employees.

[1] Decision 2001-105 ATCO Electric Ltd, ATCO Gas and Pipelines Ltd. and Northwestern Utilities Limited (ATCO Companies) Pension Filing – Negotiated Settlement, dated December 31, 2001

[2] AU Evidence, pages 6 and 7

The Pension NSA indicated that the deferred pension balances would be dealt with in future regulatory proceedings.[3] Subsequently components of the Deferred Pension Asset were dealt with in a number of proceedings and the Board directed AU to provide additional information. The Application listed three Board decisions (Decisions 2003-071, 2003-072 and Decision 2003-100 as referenced above) where the Board had last provided directions regarding the Deferred Pension Asset and other pension matters. The Application responded to all outstanding Board Directions regarding the Deferred Pension Asset.

Schedule 1 to the Pension NSA, which is attached to this Decision as Appendix 3, lists the deferred pension asset balances as of January 1, 2000, as follows:

- ATCO Gas (South) - $9.934 million
- ATCO Pipelines (South) - $2.094 million
- ATCO Gas (North) - $6.094 million
- ATCO Pipelines (North) - $2.111 million
- ATCO Electric - $2.760 million

The Board notes that the $9.934 million relating to ATCO Gas (South) as well as $2.094 million relating to ATCO Pipelines (South) were identified as being subject to the Board's determination in Application 2000350. However, Decision 2001-096[4] ATCO Gas South GRA Phase 1 which dealt with Application 2000350 referred the pension issue to the Pension Application which was dealt with in Decision 2001-105. Further the $6.094 million relating to ATCO Gas (North) as well as $2.111 million relating to ATCO Pipelines (North) were identified as being for information purposes only. The $2.76 million related to ATCO Electric does not have a similar note. Although Deferred Pension Asset amounts were included in a number of subsequent proceedings, and most recently the three decisions referenced above by AU, the Board has not yet ruled in respect of these amounts.

AU argued that Schedule 1 to the Pension NSA detailed the amounts of the Deferred Pension Asset for each of the ATCO Utilities. AU submitted that this was confirmation of the outstanding receivable and the understanding that some action would be required in the future to address this receivable.

CG submitted that the Pension NSA indicated that "The ATCO Companies' Deferred Pension Balance existing at January 1, 2000 will be dealt with in future regulatory proceedings."[5] In reply argument CG maintained that there was a lack of direction in the Pension NSA despite the fact that these amounts were both known and quantifiable at the time the Pension NSA was filed. CG submitted that the Board had yet to consider and rule on the appropriateness of amounts accumulated in the Deferred Pension Accounts. CG submitted that AU had waited, for reasons only known to AU, until June 30, 2005 to file the Application for recovery of the Deferred Pension Asset.

[3] Exhibit 02-010 IW-AU-4, Attachment 2, Pension Negotiated Settlement, page 6
[4] Decision 2001-096, ATCO Gas South 2001/2002 GRA Phase I, December 12, 2001
[5] CG Argument, page 52, which referenced Exhibit 02-10, Response IW-AU-4, Attachment 4, Decision 2001-105, page 4

In the Pension NSA Decision 2001-105, the Board noted at page 4 that neither the Negotiated Settlement nor the Decision dealt with the Deferred Pension Balances.[6] In the Board's view the terms of the Pension NSA, and particularly the notes on Schedule 1 thereof, indicate that the parties saw the disposition of the Deferred Pension Asset as being subject to further Board process.

AU argued that the requirement for Board permission to collect the Deferred Pension Asset arose because AU switched to the cash basis of pension accounting in the year 2000. AU submitted that had it remained on the accrual basis of accounting, the Deferred Pension Asset would have been amortized and collected in due course.

The Board will discuss separately below, the two components of the Deferred Pension Asset, being the Over-Funding Component and the Restructuring Component. Firstly, however, the Board will deal with an item that affects both components.

3.1 Relevance of Working Capital Treatment

AU and CG both referred to the fact that the Deferred Pension Asset had earned a return as working capital or as a reduction to no cost capital since 2000.

AU submitted that the Deferred Pension Asset has been the subject of working capital treatment on the books of each of its utilities and that this occurred in order to provide AU with a return on this outstanding receivable until it was recovered. AU submitted that the creation of the Deferred Pension Asset and its associated working capital treatment provide an explicit recognition of the amount owed to the AU.

Clause 9 of the NSA provides for the deferred balances related to pension costs to be included in necessary working capital. The Board considers that the working capital treatment agreed to in the Pension NSA is, in isolation, an indication that parties viewed the Deferred Pension Asset amounts as assets of AU and therefore as amounts to be collected in the future by AU. However, given that the amounts were subject to further Board determination, the Board is of the view that the working capital treatment is not sufficient, on its own, to conclude definitively that parties viewed the Deferred Pension Asset amounts as assets of AU and therefore as amounts to be collected in the future by AU.

3.2 Disposition of Over-Funding Component

In its evidence, at page 7 and 8, AU indicated that the Over-funding Component of $2.564 million had been recorded on the books of its utility subsidiaries as a result of AU's over-funding of the pension plan. AU explained that through to the end of 1999, AU had paid more (cash) into the pension plan than was charged for accounting purposes as a pension expense. AU noted that this asset would have been, but for the change to the cash basis of accounting, recovered from customers in future years when the over-funding reversed itself.

AU also indicated that the Over-Funding Component meant that AU had paid, in the period prior to 2000, more into the pension plan than it had collected in rates.

[6] See page 5 of the ATCO Companies Pension Filing Negotiated Settlement attached to Decision 2001-105

3.2.1 Contribution Holiday and Pension Surplus Prior to 2000

AU commenced a pension contribution holiday on April 1, 1996. The contribution holiday is projected to last until 2013.[7] During the contribution holiday none of the ATCO Utilities are required to contribute cash to the pension plan which is projected to remain sufficiently funded during that period.

Since 2000, in accordance with the Pension NSA, the ATCO Utilities have been operating on a cash basis of pension accounting. Under the cash basis of accounting, no pension expense would be forecast or collected from customers during a pension contribution holiday. Had AU remained on the accrual basis of accounting, the Deferred Pension Asset would have been amortized and collected in rates over time, despite the contribution holiday, until such time as the Deferred Pension Asset had been amortized to zero.

CG submitted that AU should be directed to refund the Defined Contribution and Defined Benefit pension plan expenses included in customer rates from April 1, 1996 to December 31, 1999. CG argued that the rates in place during this period allowed AU to continue to collect pension expense revenues, but this revenue was not contributed to the pension plan to cover forecast pension expenses because of the contribution holiday. CG argued that this amounts to an over-collection of revenue which should be refunded to customers. CG's concern regarding the contribution holiday did not appear to apply to periods after January 1, 2000 because of the switch to the cash basis of accounting at that time under which no further pension expense revenue was collected in respect of those pension plans which were operating under a contribution holiday.

The Board understands that, under the accrual system of pension accounting, pension expense revenues collected during this time would have been properly used to amortize the existing Deferred Pension Asset. The amortization of the Deferred Pension Asset allowed the utility to convert a portion of any Deferred Pension Asset to cash but did not result in an accounting gain or profit to the utilities. Had the actuaries determined that no pension expense was required during this period, any pension expense revenue would have been an accounting gain to the utility and its shareholders, but this does not appear to have been the case.

Figures referenced in CG's argument at page 41 indicate that the Over-Funding Component of the Deferred Pension Asset declined from $10.843 million at the end of 1995 to $2.564 million at the end of 1999. The Board understands that this reflects the effect of the pension expense exceeding the forecasted funding requirements for pension contributions, which were zero after April 1, 1996 for the main pension plan due to the contribution holiday, thereby causing the Deferred Pension Asset to be properly amortized during that period. Therefore, despite the contribution holiday, AU still faced a pension expense. Therefore, the Board finds that there is no basis to conclude that pension amounts collected from April 1, 1996 to December 31, 1999, during the contribution holiday, should be returned to customers.

3.2.2 Approval of Deferral Treatment and Forecast versus Actual Pension Expense

CG argued that there had been no explicit Board approval to collect the difference between pension funding and pension expense in a deferral-type account. CG noted that this lack of approval also applied to the supplemental pension plan introduced, April 1, 1996 (which also

[7] AU Evidence Section 6, Appendix A, page A-2

impacted the Deferred Pension Asset). CG argued that such differences prior to 2000 were at the risk of shareholders and the Board-approved return on equity was adequate compensation for this risk. CG also argued that if over-funding was to be treated as a deferral item (despite the lack of pre-approval) then it should be calculated as the difference between pension funding and the *forecast* pension expense in the revenue requirement rather than as the difference between the pension funding and the *actual* pension expense ultimately booked for each year. CG submitted that the forecast pension expense included in rates each year for each utility had not been provided by AU.

AU submitted that CG was wrong to characterize the Over-Funding Component of the Deferred Pension Asset as a typical utility deferral account that required Board approval. AU maintained that the Over-Funding Component did not arise because of a variance between forecasts and actuals which are typically included in deferral accounts for utility purposes. Rather, this balance arose as a natural result of the difference between accounting expense and cash funding under the accrual method of pension accounting. AU further submitted that, despite CG's contention to the contrary, it was inappropriate to include variances between the forecast pension expense and the actual pension expense for consideration in this Application.

The Board does not view the difference between the pension funding and the pension expense as a matter that would be subject to a traditional deferral account treatment. Rather, the Board views such differences to be caused by the nature of pension accounting and funding regulations. Therefore, the Board considers that AU has properly excluded variances between forecast pension expense and actual pension expense in its determination of the Over-Funding Component of the Deferred Pension Asset. Accordingly the Board finds that no adjustment to the $2.564 million Over-Funding Component amount is warranted despite CG's concern that this was an unapproved deferral treatment.

The Board understands that this funding versus expense difference would have been expected to reverse in future years under accrual accounting. The Board agrees with AU's position that the change from the accrual method of pension accounting to the cash basis of accounting prevented the Over-Funding Component of the Deferred Pension Asset from continuing to amortize towards zero as it had been doing prior to 2000.

3.2.3 Funding Discretion

CG argued that AU had on its own accord maximized the funding contributions in a period when it had an option to reduce these contributions, due to the pension surplus. CG argued that the creation of the Over-Funding Component was caused solely by the inappropriate actions of AU.

AU submitted that it only had a small measure of discretion regarding funding, which was within the range recommended by the actuary. AU further submitted that the evidence confirms that AU utilized the mid-point of the range for the assumptions into which it had any input. AU maintained that the important point with respect to the Over-Funding Component is that this funding reduces future funding that would otherwise be required from customers at some point.

The Board recognizes that pension funding amounts are determined largely by actuaries, although the company has some discretion. In the Board's view there is no evidence that AU did anything improper in making the funding contributions that it did. The Board also agrees with AU that, in any event, any excess past funding associated with any discretion that AU had regarding contributions will reduce future funding requirements. Therefore the Board finds that no adjustment to the $2.564 million Over-Funding Component amount is warranted despite CG's concern about AU's discretion as to funding amounts in each year prior to 2000.

3.2.4 Income Tax

CG argued that AU has benefited from an income tax deduction equal to the Over-Funding Component and that this should be refunded to customers if the Board allows the collection of the Over-Funding Component.

AU submitted in reply argument that CG's argument was inappropriately based on new evidence introduced in argument and was incorrect because a significant portion of the impact on income tax has been deferred by AU.[8]

The Board notes that CG-AU-38 addressed income tax and in its response, AU indicated that contributions to a registered pension plan by a company are tax deductible. The Board also notes with concern that AU did not define what it meant by significant and did not explain the implications of CG's assertions.

The Board directs AU, in the Refiling called for in Section 7 hereof, to provide further details on any income tax benefits associated with the Over-Funding Component and indicate how such income tax benefits have or will eventually benefit customers, or to explain why customers should not benefit from any income tax benefits.

3.2.5 Summary of Over-Funding Component Findings

CG submitted that AU has not made an adequate case for recovery of the Over-Funding Component. CG submitted that recovery should be denied based on lack of explicit approved deferral treatment, AU's failure to prudently reduce funding in past years, the fact the funding excess should have been calculated relative to forecast expense included in rates not relative to actual pension expense, and consideration of the income tax benefit to AU.

The Board has dealt with each of CG's concerns above and has not found any reason to change the Over-Funding Component amount.

The Board finds that the evidence indicates that on the accrual basis of accounting AU would have expected to "realize" the deferred pension asset at some point in the future when pension expenses collected exceeded cash funding requirements. There is no evidence to suggest that this was intended to change with the adoption of the cash method.

The Board also finds that AU has adequately established that the Over-Funding Component is in effect a receivable from customers and that under the cash method of pension accounting special action such as a rider is required in order for AU to collect this receivable. However, in the Board's view the receivable should be net of any associated income tax benefits that have not been or will not be eventually credited to customers, but which should have been.

Therefore, the Board considers, subject to a final determination regarding any associated income tax benefits, it is appropriate for AU to collect this Over-Funding amount.

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[8] AU Reply Argument, page 5

The Board notes that paying the Over-Funding Component will put customers in the same position they would have been in had the accounting for pensions continued on an accrual basis.

3.3 Disposition of Restructuring Component

AU submitted that that it should be allowed to collect the $20.429 million Restructuring Component arising from corporate restructurings from 1996-1999 as a pension expense from customers. AU argued that the Restructuring Component should be collected so that customers do not benefit twice from the same amount.[9] AU argued that at the time of the restructuring, customers benefited from a lump-sum cost offset equal to the Restructuring Component. AU argued that it would have collected the Restructuring Component as a natural result of accrual accounting had it not changed to a cash basis of accounting beginning in the year 2000.[10] AU's argument is that by collecting the Restructuring Component, this would offset AU's earlier payment of restructuring costs, leaving AU whole. Meanwhile customers would properly benefit (once) from the pension gain through the restructuring costs paid by AU.

AU submitted that customers will improperly benefit (a second time) from the pension gain via a reduction in pension expenses of $20.429 million unless AU is allowed to collect this amount to offset the benefit of the reduced pension expenses.

In argument CG listed five components of restructuring as identified by AU that totaled the $20.429 million Restructuring Component. CG submitted that it appears customers have received, on a forecast basis, the benefit of the $20.429 million pension gain, either as an offset to restructuring costs, severance costs or as a reduction to prior year's revenue requirement.[11]

In its response to BR-AU-6, AU reviewed certain Board Decisions that, in AU's view, contained support for its position that the Board had approved the various components of the $20.429 million restructuring costs and that those costs were offset by the pension gain. The Board finds that AU's response generally supports AU's position. However, the Board notes that in some cases it appears that the Board explicitly approved the net restructuring costs, but did not explicitly state that the total restructuring costs would otherwise have been approved for recovery from customers. Nonetheless, by approving the use of the pension asset to offset restructuring costs it is not unreasonable to assume that there was an implicit acknowledgement that the restructuring costs were valid customer costs. The Board notes that CG has acknowledged that customers have received the $20.429 million benefit.

Accordingly the Board finds that customers have received a benefit of $20.429 million through an offset to restructuring costs.

3.3.1 Value of Pension Savings

CG noted that the pension funding excess (surplus) had declined by 55% from $423.5 million at the end of 2001 to $189.4 million at the end of 2004. CG argued that, with the continuing absence of employer contributions, the excess suffered a further decline during 2005. CG submitted that the decline in the excess indicated that the value associated with the Restructuring

[9] AU Argument, page 8
[10] AU Argument, page 3
[11] CG Argument, page 51

Component has been significantly eroded due to the decline in the pension excess. CG argued that any hope or expectation that the Restructuring Component gain is still residing in the pension plan and will somehow defray the cost of future contributions appears unrealistic.[12] CG therefore submitted that there was no substance in AU's assertion that, absent AU's collection of the deferred pension amount, customers will get the pension gain twice. CG submitted that AU should not be allowed to recover the $20.429 million pension gain.

CG argued that AU had refused to provide details in support of the Restructuring Component pension gain. CG submitted that the Board should direct AU to provide an independent third party report as to the reasonableness and accuracy of the $20.429 million pension gain.

In reply argument[13] AU submitted that the pension surplus is $20.429 million higher than it would have been absent the actions of AU and that the effect is permanent and simply cannot be undone.

In the Board's view the amount of the pension gain was determined by AU's auditors and actuaries and is not something that need be re-examined by the Board. In addition, the Board understands that the pension gain caused by the departing employees will be or has been realized by customers through lower pension funding requirements and has contributed to the continuing pension contribution holiday.

The Board notes that CG does not dispute that customers received a benefit of $20.429 million as an offset to restructuring expenses. The Board also notes that the amount was equal to the actuarial estimate of the pension gain and was therefore intended to provide the pension gain to customers. In the Board's view customers will benefit from the pension gain through lower contributions. Any error in the original actuarial estimate of the pension gain is not relevant because customers will receive the actual amount of the pension gain in due course. Also, there is no evidence that the value of the pension gain has diminished. With the significant decline in interest rates that has occurred since the late 90's the Board would expect that the value of the savings resulting from not having to pay the pensions associated with the departing employees is more likely to have risen than fallen.

The Board finds no merit in CG's argument that the, originally estimated, pension gain of $20.429 million has diminished and therefore has not been or will not be realized by customers.

3.3.2 Potential Double Counting of Working Capital Return

CG argued that AU has earned a return on the Restructuring Component through its inclusion in necessary working capital. CG asserted that this return was much higher on a forecast basis than the return on the assets in the pension plan accruing to customers.

CG also argued that AU would have either borrowed funds or raised equity to carry out its operations and would have earned a return on such debt or equity. In reply argument, CG submitted that there was little if any substantiation for AU's assertion that it paid out $20.429 million "out of shareholder funds". CG submitted that it was arguable that AU received both a return on necessary working capital and a return on the associated debt and equity. CG

[12] CG Argument, page 53
[13] AU Reply Argument, page 6

argued that AU should be directed to refund amounts collected as a return on necessary working capital to avoid the problem of over-compensation.

In reply AU submitted that it was puzzled by the CG’s suggestion that AU may have received a return both on working capital and on the associated debt or equity as there was no evidence that AU was compensated for the financing cost other than through working capital/no cost capital treatment.

The Board notes CG’s argument that AU may have earned a return on the Restructuring Component both as return on working capital and on the debt or equity financing the asset. However, in the Board’s view it is a basic feature of rate regulation that utilities earn a return on rate base, including necessary working capital, by virtue of an allowed return on debt and equity capital. In effect provision of a “return on rate base” is accomplished by providing a “return on capital invested in rate base”. There is no double counting involved.

The Board also notes CG’s argument regarding the differential between the return on working capital and the return on pension assets. However, the return on pension assets does not determine the return on rate base. In the Board’s view, to the extent that it was proper to include the Restructuring Component in working capital, then it was also proper to provide the Board’s approved debt and equity return on (capital invested in) such working capital.

The Board finds no merit in CG’s concerns relating to return on working capital.

3.3.3 Summary of Restructuring Component Findings

The Board found above that customers have previously received the $20.429 million benefit of the pension gain as an offset to restructuring costs. The Board also found above that customers have or will receive once again the benefit of the pension gain through reduced pension expenses. The Board dismissed CG’s concern regarding a double counting of return related to working capital and its concern regarding the level of return on working capital versus the return received in the pension plan. The Board agrees with AU’s submission that under accrual accounting, AU rather than customers would have received the benefit of the $20.429 Deferred Pension Asset in due course.

For all of the above reasons, the Board finds that AU is entitled to collect the $20.429 million Restructuring Component of the Deferred Pension Asset.

In the Board’s view the $20.429 million to be collected from customers is essentially a repayment of the $20.429 million that AU used to offset restructuring costs. Customers have and or will realize the full benefit, through lower pension expenses which have contributed to the pension contribution holiday that has been benefiting customers since 2000.

3.4 Nine Year Proposed Amortization Period

In its Application, AU proposed to recover the Deferred Pension Asset over a nine year period, corresponding with the time remaining for the pension contribution holiday. AU indicated that the goal was to fully recover the Deferred Pension Asset prior to the time when costs to customers will increase due to the resumption of contributions following the depletion of the plan surpluses.

CG was not opposed to the nine year amortization period proposed by AU for the collection of any approved amounts.

The Board agrees with AU's view that it would be logical to collect the Deferred Pension Asset during the period when customers are not paying regular contributions to the pension plans due to the continuing pension holiday.

The Board accepts the nine year amortization period. However, the Board directs AU to propose changes to the amortization period in future GRA/GTA applications, if necessary, to achieve the goal of collecting the Deferred Pension Asset amount by the time the contribution holiday ends.

3.5 Other Pension Related Matters

CG submitted that the 19% increase in Other Post Employment Benefits (OPEB) for AE in each of 2005 and 2006 did not appear reasonable relative to the 2% increase forecast for AG and that therefore AE should be limited to a 2% increase in each year.

CG indicated that the future liability associated with OPEB for all of the ATCO Utilities was $46.6 million in 2004 and was forecast to increase to $48.1 million in 2005. CG recommended that AU be directed to provide detailed information as to these forecasts in the next GTA/GRA.

CG submitted that the Board should direct AU to file the number of members in the Supplemental Employee Retirement Plan (SERP) and the current unfunded liability allocated to each utility. CG also submitted that AU should be directed to file the formula used to assign the SERP costs to the Utilities for 2005-06. AU should also be directed to file details in future GRAs/GTAs including the number of members in the plan and any changes or enhancement to the supplemental pension plans or post-retirement benefits.

AU explained that AE's higher forecast increase in OPEB was based upon a review of historical increases while AG had relied upon its (general) forecast for inflation. AU submitted that given Alberta's booming economy, it was AG's forecast that was too low, rather than AE's being too high. AU also submitted that CG's argument on this point was inappropriate as it was not supported by any evidence that AE's forecast was unreasonable or inappropriate.

AU submitted that no action of the Board regarding OPEB was required in the current proceeding. AU argued that support for the liability regarding OPEB was not relevant at this time given that any future expenses associated with this would be justified in future proceedings.

The Board does not agree with CG that AE's forecast should be cut simply because AG had a lower percentage increase forecast. The Board finds AU's arguments in this area to be credible and is of the view that a change to AE's placeholder related to OPEB is not required.

The Board finds that no changes are required to AU's proposals regarding OPEB or SERP.

4 HEAD OFFICE RENT

AU has applied for approval to include head office rent costs in the revenue requirements of the respective AG and AE GRA and GTA applications commencing in 2005 based on a lease rate of $16.95 per square foot (psf). AU is also seeking approval of 2003 and 2004 rent expense amounts for AE based on a rental rate of $13.70 psf. The applied-for amounts for head office rent costs are as follows:

Table 1. Applied-for Rent Expenses to be included in Revenue Requirement in $000

	2003	2004	2005	2006	2007
ATCO Electric	1223	1225	1577	1577	N/A
ATCO Gas (North)	N/A	N/A	791	791	791
ATCO Gas (South)	N/A	N/A	755	755	755

In Decision 2003-071 the Board directed AE to provide, at the time of its next GTA, an independent 3rd party report demonstrating that the head office lease rates being paid by AE were at or below market value when they were renewed. The Board also directed AG, in Decision 2003-072 to provide evidence in its next GRA to confirm that the head office rental rates were market based.

Pending consideration of the applied-for head office lease amounts in this Proceeding, AE and AG utilized placeholders in the AG 2005-2007 GRA Phase I Application[14] and in the AE 2005-2006 GTA Phase I Application.[15] In this section the Board will determine the revenue requirement amounts to replace or confirm these placeholder amounts. Amounts relating to AP are deferred until its next GRA proceeding.

4.1 Introduction

The original lease for the ATCO Center was held by the AU parent company, Canadian Utilities Limited, with subleases to the predecessors of AG and AE. The lease and subleases were for a period of 20 years expiring on November 30, 2003. A rental rate of $16.95 psf was established in the 1980's and was mirrored down to the regulated utilities AG, AE and AP.[16] The renewals of the subleases were to be for a five year period commencing after November 30, 2003.[17]

In March of 2002 the ATCO Center was sold to EDCAL 2002 Holdings Limited. In April 2002 sublease renewal agreements were signed between CU and the ATCO utilities for a time period commencing April 1, 2002 and ending November 30, 2003 at a rate of $16.95 psf.

For revenue requirement purposes AE and its predecessor have proposed a rental rate of $13.70 psf for 2003 and 2004. The Board approved a rental rate of $13.58 psf for 2003 and 2004 for AG in Decision 2003-072. From 2003, AG and AE have used a placeholder amount of $16.95 psf as established in Decision 2006-024 and Decision 2006-004.

The average square footage amounts underpinning the Application are as follows:

Table 2. Average Square Footage

	2003	2004	2005	2006	2007
ATCO Electric	92,009	92,260	93,036	93,036	N/A
ATCO Gas (North and South)	N/A	N/A	91,226	91,226	91,226

14 AG 2005-2007 GRA Phase I, Application 1400690, Resulting Decision 2006-004
15 AE 2005-2006 GTA Application 1399997, Resulting Decision 2006-024
16 Transcript, Volume 2, pages 183, 184
17 Transcript, Volume 2, page 174

4.2 Square Footage

When determining the appropriate amount of rent expense to be included in the revenue requirement of the AU companies, the Board must review the appropriateness of both the square footage and the rental rate charged per square foot (psf) as signed by the ATCO utilities in the April 2002 time frame.

The square footage amounts included by the individual ATCO utilities were not challenged by interested parties. The Board notes that the square footage amounts have not changed with any significance from 2003 to 2006 for AE. The square footage for AG has not changed for the years 2005 – 2007. For these reasons the Board will accept the square footage amounts and will focus its review on the reasonableness of the lease rate per square foot used in the calculation of the rent expense for the ATCO Utilities.

4.3 Lease Rate for Years 2005-2007

In its Application, AU presented a market lease report for the downtown Edmonton area prepared by Colliers International (the Colliers Report). The Colliers Report proffers the opinion that market rates for a 185,000 square foot tenant in the City of Edmonton during the 2001/02 time frame would be between \$15psf and \$16psf.[18]

The evidence of the CG relied on the services of CB Richard Ellis for its report (CBRE Report) on an appropriate renewal rate for the ATCO subleases. The CBRE Report concluded that an appropriate market lease rate for ATCO Centre, effective April 2002, would be in the range of \$10psf to \$12psf.[19]

Both the Colliers Report and the CBRE Report reach similar conclusions with regard to vacancy rates and a tightening of the commercial rental market in the downtown Edmonton market. The Colliers Report noted that in general, vacancies were dropping and rental rates were firming towards equilibrium and eventually towards a landlord's market.[20] The CBRE Report noted the downtown market was tighter than it had been in a number of years.[21]

The CG agreed that a tenant in downtown Edmonton would have recognized that rental rates were increasing slightly. The CG submitted, however, that this tightening of the market did not justify AU's early lease renewal and an increase in the lease rate from \$13.58-\$13.70 psf to \$16.95 psf.

The Board considers that in order to arrive at a decision on an appropriate lease rate in the context of establishing the revenue requirement for the applicable test years described above, it must evaluate the prudence of the decision of each of the ATCO Utilities to renew its head office sublease at a rate of \$16.95 in April 2002. The Board recognizes that the ATCO Utilities preferred to remain co-located in the ATCO Centre building. In such circumstances, it is fair to assume that during lease renewal negotiations a landlord and a prudent tenant would be aware of, and would consider, the options available to the tenant in determining an appropriate lease rate. Notwithstanding AU's preference for the status quo, the Board considers that relocation from the

[18] Colliers International Report; ATCO Gas and ATCO Electric Market Lease Rate Study, page 18
[19] CB Richard Ellis Report, 2002 Market Lease Rate Survey, page 11
[20] Common Matters Application 1407946, Colliers International Report, page 6
[21] CBRE Report, 2002 Market Lease Rate Survey, page 2

existing premises should be one of the options to be considered in the renewal negotiations and, accordingly, must form part of the test to be applied by the Board when determining an appropriate lease rate for revenue requirement purposes.

The Board considers that there were a number of options available to AU at the time of its lease renewal. These included:

(1) build in another location and relocate (build to suit),
(2) lease in another location and relocate (relocate and lease), and
(3) renew the existing lease.

The Board will now review each of these options and provide it conclusions.

4.3.1 Build to Suit

Mr. Bradley, as the expert witness supporting the Colliers Report filed by AU, noted that a new building had not been constructed in downtown Edmonton since 1990.[22] The Colliers Report stated that a rental rate would have to be in the range of $18psf-$19psf, with lease terms at a minimum of 10 years in order to justify the building of a new office building. The Board accepts the view of the Colliers Report that the Ford Call Center, with an occupancy date of November 1, 2001 was in the time frame to make an appropriate benchmark for a new suburban building in Edmonton's northwest. The rental rates for the 80,000sf Ford Call Center ranged from $14.95 to $15.95 plus operating costs and taxes over its ten-year lease term. The Board considers that a build to suit option in a downtown location for a larger contiguous floor space could attract a higher lease rate. The Board accepts the Colliers Report that showed proposed buildings in both downtown Edmonton as well as suburban areas ranged from approximately $15psf to $30psf through a ten-year period.

The CBRE Report noted that anticipated lease costs for a build to suit option would be in the mid-to-high teens. The CG submitted that the build to suit option was priced out of the market for rental of existing space in downtown Edmonton. As such, the CG stated that the build to suit option need only be considered as an unavailable option. During cross examination with Board Counsel, Mr. Menon, the expert witness supporting the CBRE Report, stated that a build to suit option was not a realistic option as AU had existing options at much lower prices.[23]

The Board agrees with AU that the inclusion of build to suit options forms part of the range of options for AU's consideration. The Board is willing to accept the view of the Colliers Report that a build to suit option, excluding moving costs, would be well in excess of $15psf over a ten-year period. With moving costs included, the Board finds that this option would be an unacceptable alternative for AU based on cost.

4.3.2 Relocate and Lease

AU submitted that leasing in another location was not a practical option because there were no 185,000 square feet of conventional contiguous office space in the City of Edmonton at the material time. The Colliers Report noted that the ATCO Centre allowed for the cost savings related to expansion or contraction of space requirements and the sharing of common facilities,

[22] Transcript, Volume 2, page 207
[23] Transcript, Volume 2, page 262

such as main frame computer, network and IT infrastructure, security, meeting rooms, halls and office services. The Colliers Report submitted that these advantages could be worth as much as $2.00 - $3.00psf. AU submitted that co-location of the three utilities, AG, AE and AP was more efficient for management purposes and allowed AU to share its services, a common culture and assisted with employee recruitment and retention.[24]

AU submitted that the extra benefits provided by the ATCO Center are worth $2psf to $3psf but that these costs were not included in the rental cost of $16.95.[25] The CG submitted that avoided costs, moving costs and benefits of relative locations are more properly the subject of discussion and analysis in a cost benefit analysis.[26] The Board agrees with the CG and finds that AU did not provide sufficient evidence to support or quantify these amounts. The Board considers that each building will have its own unique benefits to its tenants and would have to be considered in evaluating the prospect of a lease renewal or re-location.

The CG expressed concern with regulated companies being co-located with other regulated companies, such as AG and AE. The CG also submitted that ratepayers may be paying greater rent for AU to locate close to non-regulated affiliates without evidence of possible benefits. The Board agrees with the CG that benefits or costs of co-location for the utilities are more appropriately found within a cost benefit analysis or business case.

The Board accepts AU's position that no comparable space could be found in downtown Edmonton that would provide AU with a situation that provided similar benefits that existed in their current space within the ATCO Center. Although the Board is prepared to accept ATCO's position that co-location of the utilities provides certain benefits, the completion of a business case which analyzed the benefits of remaining co-located at the ATCO Centre at the applied for rental rates versus the overall cost impacts of separating the utilities would have greatly assisted parties and the Board. The Board expects to see a cost/benefit analysis of co-location with respect to any further lease renewal, term extension or new lease arrangement.

The Board notes CG's submission that 44 Capital Blvd. could have accommodated the space requirements of ATCO, however, the Board is not convinced that the amount of space or the timing of the space available would have suited ATCO's requirements. The Board also accepts that the Manulife Phase II building did not provide a suitable office environment and therefore was not appropriate for AU's needs. The Collier Report used the example of the conversion of Manulife Phase II as indicative of the costs of converting non-typical facilities to office use. The lease of Manulife Phase II to Dynacare Kasper Medical Labs, commencing in June 2002, had a 15 year term ranging from $13psf to $15psf, with $2,000,000 of Dynacare's own money towards tenant improvements.[27] The Board accepts that the costs of converting office space into an acceptable business environment are significant and would likely put such an option out of the market even before moving costs and business interruptions are considered.

The Board considers that having few options available, and no realistic options in downtown Edmonton, the ATCO Utilities would have less leverage at the time of negotiating the lease renewals. The Board considers that it is reasonable to assume that this lack of leverage would be reflected in any lease renewal rate.

[24] Transcript, Volume 2, page 200, 211, 212
[25] Transcript, Volume 2, page 214
[26] CG Argument, page 12
[27] Colliers Report, page 11

4.3.3 Renew the Existing Lease

The Board agrees with AU, that in the case of leased space, potential tenants can be more aggressive if there are many options on the market for space in the required space range, and conversely, the landlord can be more aggressive if options are limited. The Board accepts that AU had few options in regard to its space requirements.

The Board understands that the lease renewals were undertaken at a time of a third party transaction involving the sale of the ATCO Centre building. When considering a new lease term that extended beyond the present term, a tenant would be expected to evaluate a proposed lease rate that took into account the market range in light of the term of the new lease. A prudent tenant would also be expected to consider all of its options of retaining the current lease and negotiating a possible lease renewal at a later date.

As a proxy for the market value of the ATCO Centre, the Board agrees with AU that the Telus Plaza and the Enbridge Tower, as well as Manulife Phase II, 44 Capital Blvd, and build to suit must be considered in a full market evaluation. The Board disagrees with the CBRE Report that fully discounts the Enbridge Tower as a relevant comparable.[28] The Board accepts the Colliers Report and its market range. The Board considers that the authors of the report evaluated the full market and made appropriate adjustments for the unique factors of each situation when they determined the market range contained in the report. Therefore, the Board finds that an appropriate market range for an 185,000sf tenant, in the City of Edmonton during the 2001/2002 time frame, for the years 2005, 2006 and 2007 would be in the $15 – 16psf range stated in the Colliers Report.

However, the Board agrees with the CG that the ATCO Utilities did not have sufficient market information prior to the signing of the lease renewals. The evidence demonstrates that a complete market study like the Colliers Report was not undertaken by AU at the time that the utilities entered into their lease renewal agreements. Had AU had the benefit of such an independent market study at the time of the lease renewals, AU would have found that $16psf was at the highest end of the range for a lease signed in 2002 for the years 2005 – 2007. Signing a lease that went above the highest lease amount shows a lack of thoroughness on the part of AU.

Accordingly, based on the evidence before it in this proceeding, including the Colliers Report, the Board is not prepared to approve a lease rate that is greater than $16psf, which in the Board's view represents the highest end of the range for a lease signed in 2002 for the years 2005 – 2007.

4.3.4 Conclusion

For the reasons discussed above, the Board allows AU to incorporate a lease rate amount based on the rate of $16psf into the revenue requirement of AG from 2005 to 2007 inclusive, and the revenue requirement of AE for 2005 and 2006. $16psf is the high point of the market range specified by the Colliers Report filed by AU. The record discloses insufficient evidence to support a market rental amount in excess of the $16psf. The Board is of the view that $16psf, which represents the high point of the market range specified in the Colliers Report is appropriate to be included in revenue requirement given the relevant circumstances that give context to the

[28] CBRE Report, page 10

options faced by AU, options which the Board has considered to be limited at the time of the lease renewals.

With respect to the future, given the concerns expressed by the Board with the timing and thoroughness of the evidence filed in this proceeding, the Board directs AU, in **the next proceeding which considers new leasing arrangements** (including extensions or renewals of existing arrangements), to provide an independent market study examining the build to suit option, the alternative locations option and the option of remaining at the ATCO Centre (if that is the preferred course).

In addition, the Board would expect the ATCO Utilities to prepare a business case in support of the applied for lease amount. Such a business case should discuss, and numerically quantify, the rationale for the rental decision of the ATCO Utilities, and should include a cost/benefit analysis of the build/relocation options. The business case must also address and quantify the costs and benefits of retaining the ATCO Utilities in the same building versus different locations.

4.4 Lease Rate for Years 2003 and 2004

In the Application the Board was requested to approve the current placeholders for AE’s rent expense amount of $1,223,000 and $1,225,000 for the years 2003 and 2004 respectively based on a lease rate of $13.70psf.

The Board finds that the amounts as applied for in these years to be appropriate and therefore approves the inclusion of rent expenses in AE’s revenue requirement in the amount of $1,223,000 for 2003 and $1,225,000 for 2004.

5 PREFERRED SHARES

The preferred shares issue in this Application results from a Board Direction (Preferred Shares Direction) in the Generic Cost of Capital Decision 2004-052. In that Decision the Board stated as follows:

> In earlier sections, the Board noted that the 2004 approved common equity ratios in this Decision for the ATCO utilities were not adjusted to reflect any impact of ATCO’s use of preferred shares. The Board notes that there was essentially no evidence presented regarding the impact of preferred shares on the required common equity ratios.
>
> The Board has recognized in previous decisions that during the period of time when income tax rebates were in place, it was prudent to utilize preferred share financing in place of debt.
>
> However, the Board considers that there may be merit in further consideration of the appropriateness of the continuing use of preferred shares as a form of financing, to understand the redemption options and to fully explore the related implications and options.

> The Board directs ATCO to address the appropriateness of the continuing use of preferred shares as a form of financing, in the next Phase 1 GRA/GTA for ATCO Gas, ATCO Pipelines or ATCO Electric, whichever comes first.[29]

While AU and the CG held different views as to the exact meaning and intent of the Board's Preferred Shares Direction, there appeared to be agreement among the parties that this Application should include an assessment of the cost effectiveness of continuing to include preferred shares as a form of financing for the ATCO Utilities as opposed to the conversion of all or some of the preferred shares to debt. The Board concurs with this view. The Board considers that the Preferred Shares Direction contemplated that the Board would review further evidence and submissions in a future proceeding, such as this Application, to review the appropriateness, including the cost effectiveness, of continuing to use preferred shares.

However, the parties differed on the extent of the cost effectiveness assessment. AU submitted that it was not asking for a specific target range to be approved at this time but was simply requesting that the Board permit the continued use of preferred shares. On the other hand, the CG considered if there is to be a preferred component in the capital structure, the Board should also determine what proportion of the capital structure equity preferred shares should constitute.

The Board considers that a proper cost effectiveness assessment of the continued used of preferred shares would by necessity involve consideration of the existing amount of preferred shares in AU's capital structure. Therefore, the Board will provide its views on target preferred shares ratios with reference to AU's existing preferred shares should the Board determine that it is cost effective to continue to use such financial instruments.

5.1 Cost Effectiveness of Equity Preferred Shares

AU submitted that its preferred shares have ensured that its customers have enjoyed the benefits of the lowest cost financing on the most flexible terms available in the Canadian financial market because AU's existing preferred shares provide support to its credit rating.[30] The Board acknowledges that the preferred shares represent a subordinate claim on cash flows and assets versus senior debt and accordingly assist the AU credit rating. The Board also understands that a basic characteristic of debt markets is that directionally, interest rates for borrowers rise as credit ratings fall. The Board therefore accepts that AU's interest rates on new debt would be expected to rise by some amount if AU's preferred shares were replaced by debt. The Board also understands that while the interest rates payable on existing debt would not rise, the market value of existing debt would be expected to be negatively impacted if AU's credit rating declined. This in turn could potentially have a future negative impact on the capital markets as it may relate to the availability of capital from the existing debt holders.

The Board notes that AU provided an analysis[31] indicating that replacing preferred shares with debt would provide initial savings but the cumulative savings would become negative within four years due to the cumulative higher costs of new debt issued each year. In contrast CG provided an analysis[32] which it submitted illustrated that preferred shares are not cost effective

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[29] Decision 2004-052 Generic Cost of Capital, page 55
[30] AU Evidence, page 5-5, lines 23-24
[31] AU Updated Evidence, Exhibit 02-033
[32] Exhibit 02-035-001, CG-AU-70, Schedule 1

over the period 2006-2011 assuming that debt costs increase by 10 basis points due to replacement of preferred shares with debt.

The Board notes that the approach used by both AU and CG to determine the cost effectiveness of preferred shares is dependent on AU's specific debt requirement needs, with a focus on the next four to six years. However, all debt would eventually be refinanced and accordingly would be affected by any lower credit rating. In the Board's view, the cost effectiveness of using preferred shares should be evaluated on a more generic basis that considers the long-run steady-state impacts and that is not dependent on the particular immediate borrowing needs of AU. This can best be accomplished by comparing the total yearly cost of non-common equity financing with and without preferred shares at current market rates for debt and preferred shares. In this context "current" refers to the most current market figures available on the record of this proceeding.

AU's updated evidence indicated that preferred shares had a current market cost of 4.60% and that AU's income tax rate was currently 31.37%. This translates to a pre-tax cost of (4.60/ (1-0.3137)) 6.70%. AU's updated evidence indicated that the current market cost for long-term debt was 5.75%. As a result, preferred shares were estimated to have a current market cost that was 95 basis points higher than the current market cost of debt, at the time of that estimate.

The ATCO Utilities proposed a preferred equity ratio of 6% and a debt ratio that approximates 57% across the four ATCO Utilities, which would then approximate 63% if the preferred shares were replaced with debt. In these proportions, the debt portion of capital is approximately 10 times larger than the preferred equity portion of capital. On this basis, the Board calculates that if the debt costs were to rise by any more than approximately 10 (i.e. 95/10) basis points, due to the replacement of preferred shares with debt, then the added cost of the (then) approximately 63% debt component would outweigh the approximate 95 basis points savings on the current 6% preferred share component. The Board notes that, in keeping with its steady-state approach, this calculation assumes that the added cost would apply to both existing and new debt.

AU's expert, Mr. Neysmith indicated[33] that replacing AU's preferred shares with debt would lead to a debt credit rating downgrade of at least one to two notches. AU estimated that this would increase its debt interest costs by 30 to 60 basis points.[34] AU also provided a letter[35] from a financial market advisor, Mr. Engen, which indicated that AU's interest costs would rise by 5 to 10 basis points if the market viewed CU's regulatory environment to be largely unchanged and 20 to 40 basis points if the market viewed CU's regulatory environment as having worsened because of the Board's decision to remove the preferred shares. Both of these estimates were based on current market conditions. Mr. Engen indicated that in a less attractive spread environment, the differential could be expected to widen.

CG did not appear to agree that the elimination of AU's preferred shares would necessarily lead to higher debt costs. CG noted that the fixed charge ratio remains essentially unchanged with or without preferred shares, indicating no increase in financial risk. CG submitted[36] that AU's evidence indicated that higher impacts on the debt costs would only occur if the Board failed to provide solid reasons for any decision to replace preferred shares with debt and the market

33 AU Evidence, page 2-11
34 AU Evidence, page 5-22 and 5-23
35 AU Evidence, Exhibit 6
36 CG Argument, page 68

formed a negative perception of such a Board Order rather than from any significant increase in financial leverage. CG submitted that if the reason for any change in the preferred component is based on the principle of cost effectiveness, then investors are more likely to perceive the change as a positive one, rather than a negative one.[37] However, CG then stated that the presence of some preferred shares could conceivably impact debt costs positively.[38] Specifically, CG indicated that, based on its interpretation AU's evidence establishes a minimal financial risk impact of 5 to 10 basis points,[39] and therefore the proportion of preferred shares should be closer to the low end of the historical range of 2% to 10%, rather than the existing 6% level.

In the Board's view, CG is less than clear in its position as to the number of basis points, if any, by which new debt issue costs would rise with the removal of preferred shares or whether or not preferred shares are cost effective.

It is not clear how many basis points would be added to AU's debt costs if preferred shares were replaced with debt. However, the Board accepts that directionally it should expect some increase in debt costs in such a scenario. The Board accepts AU's submission that the debt cost impact would vary depending on market conditions. In the Board's view, a 10 basis points or greater increase in debt costs for AU resulting from the discontinuance of the use of preferred shares in AU's capital structure would be sufficient to demonstrate the continued cost effectiveness of employing preferred shares. The Board considers the evidence provided by AU and its experts persuasive that the discontinuance of the use of preferred shares could be expected in the present market conditions to increase AU's debt costs by approximately 10 basis points. The Board also notes that AU's evidence indicated that the impact could be as high as 60 basis points. Therefore the Board finds that the continued use of preferred shares is cost effective at this time.

Therefore, the Board accepts that some level of preferred shares can to be utilized by AU at this time.

5.2 Target Ratio of Preferred Shares if Retained

AU stated that it was not asking that a specific target range, for the percentage use of preferred shares, be approved at this time. AU asked that the Board permit the continued issuance of preferred shares as is dictated by management in light of financing needs and financial market conditions.

CG submitted that the Board should address what proportion of the capital structure, if any, equity preferred shares should constitute. CG further submitted that the Board should direct AU to redeem the series Q, R and S preferred shares which are open for redemption and that this would result in the preferred share level falling to a more appropriate level of about 3%.

In reply Argument, AU submitted that the scope of this proceeding included determining whether preferred shares are cost effective but did not include a determination of what proportion of the capital structure preferred shares should constitute. AU submitted that there was no evidence, information requests or intervener cross-examination on this issue in the current proceeding.

[37] GG Argument, page 68
[38] CG Argument, page 70
[39] CG Argument, page 71

Under cross-examination by Board Counsel, AU indicated the optimum amount of preferred shares had been estimated by AU to be within a range of 5% to 10%.[40]

In Section 5.1 above, the Board concluded that the 6% level of preferred shares was cost effective. This 6% falls within the range identified by AU as being optimum. The Board accepts the evidence of AU on this point at this time.

Accordingly, the Board accepts AU's position that there is no need to alter the status quo regarding AU's use of preferred shares.

6 EXECUTIVE COMPENSATION

6.1 Overview

In Decision 2004-049, the Board issued the following direction with respect to Executive Compensation:

> Consequently, the Board directs the ATCO Utilities to file an updated executive compensation study, as described in the following direction that includes the following information:
>
> (i) Comprehensive information respecting total compensation benchmarking for the ATCO/CUL/CU Inc. positions allocated in part to the ATCO Utilities and the ATCO Utility executives.
>
> (ii) Justification for the Board of Director fees and fees and compensation payable to the non-executive Chairman
>
> (iii) Explanation of the value to customers provided for the costs incurred. More detailed information must be provided to demonstrate what services are performed and the absence of redundancy between positions in the Office of the Chairman and Corporate Office compared to the ATCO Utilities
>
> (iv) Demonstration that the costs allocated to the ATCO Utilities are reflective of the services provided and the corporate changes following the sale to Direct Energy
>
> (v) Justification of the appropriateness of salary costs compared to market and allocated to the ATCO Utilities including an analysis of the compensation structure and mix of salary and long term benefits chosen by the company. Identify costs that should be shareholder costs vs. allocated costs
>
> (vi) Justification of any long term incentive or bonus compensation payable to members of Office of the Chairman, the Corporate Office and the Utility executives that is being allocated to any of the ATCO Utilities
>
> (vii) Details respecting pension expensing and funding arrangements for the Office of the Chairman, the Corporate Office and the Utility Executives. Clearly identify how these costs are allocated to customers now and any future liabilities faced by customers. Clearly disclose any supplemental benefits available to specific employee groups, officers, or executives that could have cost implications for customers

[40] Transcript, Volume 3, page 411

(viii) Justification if the Inflation and Progression factor, for the Office of the Chairman and Corporate Office and for ATCO Utility executives, if any, that is being used for cost allocation purposes, is different from the general wage inflation factor used in the GRAs/GTAs

In response to the Board direction, AU engaged Towers Perrin to prepare a comprehensive report respecting total compensation including benefits for the executives in the utilities, Office of the Chairman and the Corporate Office (collectively the Executive Group). Total Target Cash (TTC[41]) and Total Direct Compensation (TDC[42]) were compared to a significant number of comparable corporations. The report included an examination of salary, target bonus, and expected value of long term incentives. The number of ATCO executives in the Executive Group totaled thirty-one; five in the Office of the Chairman, six in the Corporate Office, seven in ATCO Electric, eight in ATCO Gas and five in ATCO Pipelines. This Application requested the Board to confirm the existing executive compensation placeholders within the revenue requirements for ATCO Gas for the test years 2005 - 2007 and for ATCO Electric for the test years 2005 and 2006. The Application did not include an amount in respect of the revenue requirement of ATCO Pipelines for years subsequent to its last test year in 2004.

6.2 Towers Perrin Report – Methodology and Scopings

AU submitted that Towers Perrin was a recognized expert in preparing executive compensation reviews and benchmarking and that it used its standard approach to the selection of comparator groups for assessment of the Executive Group's compensation. Towers Perrin found it appropriate to use a slightly different group for the operating companies than for the Office of the Chairman and the CU Corporate Office. This approach is typical in such compensation reviews regardless of whether the companies were regulated or non-regulated.

AU noted that the Towers Perrin study concluded that on the average the TDC for the Executive Group was at 91% of the market 50th percentile, but was still within the plus or minus 10% range of reasonableness identified by Towers Perrin. AU was also of the view that the data presented by Towers Perrin confirmed that individual components of TTC (salary and target bonus) was also reasonable.[43] AU submitted that as long as the overall compensation for the Executive Group was at a reasonable level collectively, the Board should not focus on any sub-group or combination of groups within the Executive Group.

In addition, AU submitted, and Towers Perrin confirmed, that revenues for AG were reduced for certain items to reflect the impact of commodity flow-through revenues (Commodity Flow-Through Revenues) for the purposes of its assessment.[44] However, for AE or AP, Towers Perrin did not exclude, any Commodity Flow-Through Revenues, being energy or transmission charge revenues, as such revenues were not significant for those companies. Towers Perrin did not exclude costs or revenues paid by a utility to a non-utility affiliate (Flow-Through Revenues). Towers Perrin indicated that other companies in the study have Flow-Through Revenues included in the data; however, Towers Perrin had no way of segregating such revenue out of the comparator group. Towers Perrin confirmed that excluding all Flow-Through Revenues within the AU Group would not have a significant impact on pay since the empirical relationship of pay

41 TTC = Salary plus target bonus
42 TDC = TTC plus Expected Value of Long Term Incentives
43 AU Argument, page 29
44 AU Argument, page 32

to the total revenue for the comparator group at the revenue levels of the ATCO Group produced a gently sloping line.[45]

The CG noted that, collectively, the salaries for the Office of the Chairman and ATCO Corporate Office exceeded the 50th percentile according to the Towers Perrin study. In addition, CG argued that the revenues used by Towers Perrin in the study were overstated in excess of $1 billion due to double counting of Flow-Through Revenues, primarily revenues paid by the utilities to ATCO I-Tek/ITBS for information technology, and customer care and billing services. CG submitted that when the double counting was removed, the Office of the Chairman salaries would be 117% of the 50th percentile and urged the Board to reduce the Office of the Chairman salaries to no more than 110% of the 50th percentile after excluding two positions that CG considered were redundant.

The Board agrees with CG that AU's total revenues appear to be over-stated due to some amount of double counting of Flow-Through Revenues. However, the Board notes that the Towers Perrin survey provided evidence that the TDC reflected that a certain amount of Flow-Through Revenues were also double counted in the overall data in the comparator group. In addition, Towers Perrin advised that for the AU Group, the relationship of changes in pay levels to changes in total revenues was insignificant at the ATCO Group levels, and therefore pay would not be significantly impacted. The Board finds appropriate Towers Perrin's consideration of Flow-Through Revenues for purposes of determining a reasonable TDC level for the Executive Group.

The Board notes CG's recommendation that the market competitiveness of the total compensation package should be based on a consistent group of meaningful comparator organizations. Furthermore, the CG recommended that in the alternative, should the Board accept that the compensation market comparison can be conducted in the separate components using differing comparator groups, then AU should be required to augment the report findings by including the dollar value of the comparator groups' average salary and other components.

The Board accepts that the Towers Perrin report was developed utilizing a standard approach and that this approach was the basis for Towers Perrin's findings regarding the TTC and TDC for the Executive Group. Therefore, the Board will not require a revision to the Towers Perrin report to provide a consistent group of corporations for all elements of compensation. The Board notes, however, that an indication of the dollar value of the comparator group's average salary, TTC and TDC would have been of assistance to the Board and would expect that that information would be supplied in any future compensation review analysis.

The Board accepts the Towers Perrin study and analysis and the Towers Perrin conclusion that TDC for the ATCO utility executives, the Office of the Chairman and the Corporate Office is within a reasonable range. The Board does not view it as appropriate to look at the individual executive sub-groups in circumstances where the group as a whole is within a reasonable range and issues of redundancy[46] and efficiency are not at issue. The Board recognizes that salaries within a particular sub-group will be variable and dependent upon experience and level in the organization. Therefore, the Board considers that a reduction to the Office of the Chairman

[45] Transcript Volume 4, page 471
[46] The issue of redundancy is addressed Section 6.5.

salaries to no more than 110% of the 50th percentile, as suggested by the CG, is not warranted at this point in time.

For all of the foregoing reasons, the Board finds, subject to the provisions of Section 6.6, that no adjustment to the TDC for the Executive Group is necessary at this point in time.

6.3 Benefits

AU requested Towers Perrin to assess the market competitiveness of benefits for employees to support inclusion in revenue requirement of existing placeholders for the utility executives. The assessment shows that the AU benefit program (excluding employee contributions) is 89.4% of the 50th percentile. The assessment can be found in Appendix 4.4 of the Application.

CG urged the Board to note that the Senior Executive Retirement Plan (SERP) component of executive benefits was at approximately the 60th percentile of the median. Towers Perrin conducted a comparison of the AU Pension Plan and has confirmed[47] that the overall Executive Pension plan did not stand out in any material way.[48]

The Board notes that no other party raised concerns with respect to the utility placeholders relating to benefits or SERP.

Consistent with the views of the Board expressed with respect to TDC above, the Board views it as appropriate to consider the benefits portion of executive compensation in the aggregate. Given that the AU group benefits were assessed by Towers Perrin to be at the 89.4% of the 50th percentile, the Board finds that placeholders relating to Supplemental Pensions and OPEB to be reasonable and approves their final inclusion in revenue requirement for the applicable utility test years.

6.4 Board of Directors Fees

The Towers Perrin report included a review of Directors Compensation which showed that total compensation for directors of Canadian Utilities Limited and CU Inc. was between the 25th and 50th percentile of the comparator group. The Board notes that no parties objected to the level of total compensation for directors.

The Board considers that the level of total compensation for directors of Canadian Utilities Limited and CU Inc. is reasonable and therefore, approves the amounts included in the revenue requirements as forecast in the Applications.

6.5 Redundant Positions and Allocation of Costs of Non-Utility Executive Positions

Redundant Positions

AU provided job descriptions for each of the 31 executive positions included in the Towers Perrin report.[49] AU argued that the overall corporate structure and executive staffing was appropriate to address the governance and functional responsibilities of its organization.

[47] Transcript, pages 554 - 560
[48] Transcript , page 558
[49] BR-AU-12 Attachment

AU claimed that in the current climate of increased scrutiny and related reporting requirements, its structure and processes are needed to address the added responsibilities associated with ensuring completeness and accuracy of all financial disclosure. In addition, AU claimed that its organizational structure provides for continuity of performance through succession planning. AU submitted that the utilization of Head Office personnel to perform a variety of key responsibilities for all of the regulated utilities resulted in benefits due to economies of scale that reduce the overall costs to the ratepayers. AU submitted that any overlap in the present organizational structure was minimal and was required to ensure that the responsibilities of the overall group were carried out in a prudent fashion.

The Board agrees with AU that a certain amount of executive overlap is necessary to provide for continuity of business in a prudent fashion and to generally provide for a measure of operational flexibility. The Board finds no redundancy within the Executive Group.

CG suggested that two positions within the Corporate Head Office, the Managing Director Global Enterprises and Vice President Project Development provided no direct benefit to the utilities and their allocated costs should be removed from revenue requirement.

ATCO maintained that the entire Corporate Head Office group had oversight responsibilities for all companies in the group including both regulated and unregulated. Furthermore, AU explained that all individuals within the Corporate Head Office have a portion of their salary allocated to all ATCO companies, with the result that executives working solely for the utilities have a portion of their costs allocated to non-regulated entities.

The Board notes the CG's argument that there was no direct benefit provided to the utilities by the Managing Director Global Enterprises and Vice President Project Development positions. The Board also notes AU's testimony[50] that while theses positions may not provide a direct operational benefit to the utilities, employees occupying those positions participated in the management of the utility and non-utility companies in the group.

The Board recognizes that each member of a management group provides some benefit to the entities it is charged with managing. The Board considers that the positions held by senior executives include expansive scope of influence and authority such that from time to time, those positions will be required to provide strategic direction for the entire group of companies to meet the changing market and service requirements in a dynamic economic climate.

Allocation of Costs of Non-Utility Executive Positions

The Board notes that the allocation of the Corporate Head Office costs to the utilities is based upon a long-standing Board approved formula that attributes a portion of the costs of management within the Corporate Head Office group who perform utility and non-utility functions. The formula is based upon ratios of revenues, total assets and capital expenditures amongst the ATCO and CU companies in the group. The Board considers that the aforementioned allocation method which results in executives working solely for the utilities having a portion of their costs allocated to non-regulated entities provides a counter balancing or averaging effect to the lack of direct benefits from the Managing Director Global Enterprises and Vice President Project Development positions.

[50] Transcript, Volume 4, pages 463-465

Additionally, the Board also notes CG's concern with the inputs to the formula used to allocate Office of the Chairman and ATCO Corporate Office costs to the utilities. The CG submitted that any allocation should be adjusted so as to reflect the exclusion of Commodity Flow-Through Revenues. Furthermore, Flow-Through Revenues (affiliate revenues) should be removed for purposes of allocating costs to the utilities. The Board notes with agreement AU's submission that it has already implemented in these proceedings a prior direction of the Board to remove Commodity Flow-Through Revenues from the allocation of head office costs and that AU considered that Flow-Through Revenues were reasonable and appropriate. Therefore, the Board considers that the adjustment to the allocation process as proposed by the CG is not required.

Accordingly, the Board does not agree with CG that the exclusion of the costs associated with the Managing Director Global Enterprises and Vice President Project Development are appropriate.

Conclusion

For all of the foregoing reasons, the Board approves the number of executives in the Executive Group and except for a portion of the utility executive variable pay program (Utility Executive VPP) bonus addressed in Section 6.6 below, the Board approves the allocation of the costs for the Executive Group, in the manner described in the Application. The Board expects that in future GRAs / GTAs, each regulated entity will file the organizational chart for its entity and the charts for the Offices of the Chairman and the Corporate Head office and that any modification of existing positions or the addition or deletion of positions would be explained.

6.6 Utility Executive Variable Pay Program

The Utility Executive VPP provides a variable pay amount for utility executives based upon achieving a minimum threshold in operations and financial metrics. AU indicated that no forecast for incentive compensation for executives within the ATCO Corporate Office or the Office Chairman had been included within the revenue requirement forecasts for ATCO Gas or ATCO Electric.

AU submitted that the Utility Executive VPP, was reasonable and should be approved because performance based incentive pay was a well established compensation principle. AU argued that the Utility Executive VPP represented a prudent approach to executive compensation since the utility executives have a much greater opportunity to impact and influence utility efficiencies. AU claimed that the current Utility Executive VPP program is different from the program recently addressed in the ATCO Gas and ATCO Electric rate cases. AU argued that CG inappropriately quoted from argument presented in the ATCO Gas 2005-2007 proceeding and the CG evidence presented therein. AU argued that no such evidence was presented in this proceeding and therefore, any reliance on this untested evidence which was presented for a different purpose has no validity in this proceeding.

The Board notes CG's argument that only the portion of Utility Executive VPP related to operational metrics should be included in the revenue requirements in relation to utility executives and that the portion of Utility Executive VPP related to incremental earnings should be borne by the shareholders. CG submitted that this treatment would provide ATCO with the necessary funding to be competitive in the market.

CG did not oppose AU's proposed deferral accounting treatment for the Utility Executive VPP.

In the ATCO Gas 2005-2007 GRA Phase 1 decision, Decision 2006-004, the Board denied the inclusion of VPP for non-executives related to financial performance and approved the inclusion of VPP for non-executives related to operational metrics.[51] The Board came to a similar result in the ATCO Electric 2005-2006 GTA Phase 1 decision, Decision 2006-024.[52]

The Board has reviewed the structure of the Utility Executive VPP program in this Application and is not persuaded that the 50% portion of the Utility Executive VPP related to achievement of increased returns to shareholders will translate into improved utility operational efficiency or other utility benefits. Therefore, the portion of the Utility Executive VPP related to achievement of increased returns is not approved for inclusion in utility revenue requirement. The Board agrees with CG[53] that the portion of the Utility Executive VPP related to the achievement of operational metrics should be included in revenue requirements.

Accordingly, the Board directs AU in the Refiling provided for in Section 7, to revise the placeholder amounts for Utility Executive VPP in revenue requirement to reflect only the portion of the Utility Executive VPP related to the achievement of operational metrics.

In addition, the Board approves the use of a deferral account to reconcile the Utility Executive VPP for the operational component.

6.7 Inflation and Progression factor, for the Office of the Chairman, Corporate Office and for AU Executives

An inflation factor of 3% per year was used to develop the forecast for labor costs for the Office of the Chairman and ATCO Corporate Office. Progression factors were not included in addition to inflation.

AU submitted that the 3% inflation factor was not materially different from the wage inflation factors used by AG and AE which ranged from 3.25% to 3.75%. Progression factors were also not included in these numbers.

The Board notes that parties did not comment on the inflation factors used to adjust the TDC for the Executive Group. The Board considers that the 3% inflation factor used to develop the labor costs for the Executive Group is reasonable and hereby approves the amounts reflected in revenue requirements as adjustments for inflation.

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51 EUB Decision 2006-004 AG 2005-2007 GRA, page 63: “However, where the benefit is increased return to AG, the Board does not view funding that portion of the VPP through rates to be appropriate. This would be consistent with previous Board decisions. Therefore, the Board denies inclusion of the 50% of the VPP that focuses on financial returns, but approves the 50% that will be awarded for operational targets.”

52 EUB Decision 2006-024 AE 2005-2006 GTA, page74: “However, where the benefit primarily provides an increased return to AE, the Board considers that it is not appropriate to fund the portion of the variable program through rates. Therefore, the Board denies inclusion of the 50% of the variable pay program that focuses on financial returns.”

53 CG Argument, page 33 June 21, 2006

6.8 Compensation Mix

Decision 2004-049 directed AU to provide a justification of the compensation mix. Specifically, the Board stated its expectation[54] of AU to justify the proportionate level of salaries to be allocated to ratepayers relative to other elements of total compensation.

The Board notes the key findings in the Towers Perrin study wherein the salary, TTC and TDC were at 98%, 106% and 91% respectively as a percent of the market 50th percentile. Furthermore, the Board notes that the Towers Perrin evaluation of the AU group benefits compared to a group of fifteen companies showed that the AU group was at 89.4% of the median. The Board also received further evidence on this matter through AU's responses to IRs[55] and during cross examination of the AU witnesses by Board Counsel.[56]

Towers Perrin responded to cross-examination by Board Counsel on the issue[57] of mix between the compensation elements paid by the ratepayer and shareholder by indicating that the issue fell within management's discretion and involved balancing internal versus external competitiveness and that the different levels of compensation elements were not a concern in their evaluation.

Consistent with Board's approach in Section 6.2 of considering the Executive Group as a unit for purposes of determining whether the TDC for the group is reasonable, the Board has evaluated the compensation for the Executive Group as a single group and finds reasonable the mix of TDC and TTC and benefits for the test years applied for in this Application.

Notwithstanding the information provided on the record of this Application, the Board finds that AU has not fully complied with the Board's directions. The Board expects that subsequent studies include a section that compares the mix of the TDC and that portion of the incentives to executives that would be provided by the shareholder. Furthermore, the Board notes that the Towers Perrin study compared AU 2005 annualized compensation to 2004 benchmark data. The Board directs AU, in the next proceeding in which executive compensation is reviewed to provide additional evidence on the matter regarding mix to fully comply with the Board's directions and that future studies report comparisons be adjusted, where possible, for the same year as the data.

6.9 Placeholders

The Board also directed the following in Decision 2004-49, in Directive No. 5:

> The Board directs the ATCO Utilities to file the aforementioned updated executive compensation application, in the next ATCO Gas GRA; ATCO Pipelines GRA or the ATCO Electric GTA, whichever comes first. All of the ATCO Utilities should use placeholders so that the one GRA or GTA handles the executive compensation issues for the allocated costs and the ATCO Utilities executive compensation for all utilities.

Placeholders in the ATCO Gas 2005-2007 GRA and ATCO Electric 2005-2006 GTA were identified in those proceedings and the placeholder amounts were part of the revenue requirements subject to final approval in compliance filings subsequent to Decision 2006-004 for

[54] Decision 2004-049, page 36
[55] Response to IR CG-AU-32
[56] Transcript, pages 565 - 568
[57] Transcript, page 567

AG and Decision 2006-024 for AE. These placeholders were summarized in Exhibit 02-038 (Appendix 2 attached hereto). In Section 6.6 above, the Board has determined that the amounts for AG and AE placeholders require revision for the reasons stated therein.

ATCO Pipelines did not file a GRA in respect of the years 2005-2006. The placeholders for executive compensation for ATCO Pipelines 2003-2004 GRA were adjusted in the revenue requirements approved in Board Decisions 2004-049 and Compliance Filing Order U2004-389.[58]

6.10 Future Executive Compensation Reviews

Having accepted the Towers Perrin study in this Application in respect of the AG and AE placeholders for 2005-2007 and 2005-2006, respectively, the Board will not require a similar study to be filed in respect of executive compensation for the test years 2007 or 2008 for any of the ATCO Utilities unless a material structural change should occur in any of the Office of the Chairman, the Corporate Office or in the executive team of the applicable utility. The Board would expect to see a similar study prepared and submitted in respect of test years subsequent to 2008 and should take into account the comments and directions of the Board set out in the above sections.

7 REFILING

The Board directs AU to file a Compliance Filing Application (Refiling) addressing the matters directed herein to the Board and all parties on or before November 22, 2006.

Further, the Board directs AU, in its Refiling, to include a detailed revenue requirement reconciliation (including all calculations) for the applicable test years for each utility (AE Transmission and Distribution, AG North and South and AP North and South).reflecting the changes from existing placeholders as a result of the Board's determinations in this Decision.

Further, the Board directs AU, in its Refiling, to attach an updated version of Exhibit 02-038 (Appendix 2 attached hereto) which shall supplement the existing document by the addition of the amounts established in substitution for the placeholders by this Decision.

8 APPROACH TO COMMON MATTERS GENERALLY

The parties are aware that the Board is continually seeking ways in which to streamline its proceedings to improve efficiencies, reduce costs and expedite decision making.

The Board appreciates the efforts of the ATCO Utilities and interveners to achieve process and cost efficiencies by identifying matters common to each of the ATCO Utilities and dealing with these matters through a common matters filing rather than in separate and duplicative GRA/GTA proceedings. The use of placeholders in the individual utility proceedings greatly enhanced process time, ensuring that regulatory lag with respect to rate and other customer impacts was minimized.

[58] Order U2004-389 dated October 20, 2004 Re: Compliance Filing

The Board encourages this approach in future to the particular common matters dealt with in this Decision and would support such an approach to other matters that may be common to two or more of the ATCO Utilities when timing and circumstances so warrant. For illustrative purposes, these matters might include one or more of the following:

- consideration of the continued appropriateness of the corporate allocation formula;
- cost of debt;
- corporate reorganizations;
- outsourcing of utility functions; and
- material changes in legislation, common methodical approaches, accounting, financial disclosure, or tax.

9 ORDER

IT IS HEREBY ORDERED THAT:

(1) AU shall comply with all Board directions in this Decision.

(2) AU shall re-file its 2005 - 2007 Common Matters Application as a Compliance Filing Application, on or before November 22, 2006, incorporating the findings in this Decision.

(3) In the Compliance Filing Application, AU shall include all of the supporting schedules necessary for the Board to make its final determination respecting AU's Common Matters, subject to the replacement of placeholder amounts. The Compliance Filing Application shall be at a level of detail sufficient to reconcile with the original Application, and to demonstrate compliance with the Board's findings.

Dated in Calgary, Alberta on October 11, 2006.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

B. T. McManus Q.C.
Presiding Member

(original signed by)

J. I. Douglas, FCA
Member

(original signed by)

M. L. Asgar-Deen, P.Eng.
Acting Member

APPENDIX 1 – HEARING PARTICIPANTS

Name of Organization (Abbreviation) Counsel or Representative (APPLICANTS)	Witnesses
ATCO Utilities L. E. Smith L. Keough K. Beattie	J. Beckett I. Bradley O. Edmondson J. Lindsay F. MacDonald J. Murta R. Neumann B. Neysmith D. Wilson A. Witts W. Wright
Canadian Federation of Independent Business M. Stauft	
Consumer Group (CG) – Comprising of: Consumers Coalition of Alberta (CCA) J. A. Wachowich City of Edmonton and Alberta Urban Municipalities Association of Alberta (AUMA) J. A. Bryan Public Institutional Consumers of Alberta (PICA) N. McKenzie Utilities Consumer Advocate (UCA) R. Henderson	A. Menon

Alberta Energy and Utilities Board Board Panel B. T. McManus, Q.C., Presiding Member J. I. Douglas, FCA, Member M. L. Asgar-Deen, P.Eng., Acting Member Board Staff B. McNulty (Board Counsel) L. Kelly D. Popowich S. Allen A. Laroiya	

APPENDIX 2 – EXHIBIT 02-038

Exhibit 02-038 -
Appendix 2

(Consists of 10 pages)

APPENDIX 3 – SCHEDULE 1 TO THE PENSION NSA

IW-AU-4
Attachment 3

Schedule 1

The ATCO Companies
Deferred Pension Balances - (on a Cash Basis)
At January 1, 2000
$'000's

	Deferred Pension Asset		
ATCO Electric			
Transmission	662		
Distribution	2,098		
		2,760	
ATCO Gas (South)		9,934	Note 1
ATCO Pipelines (South)		2,094	Note 2
ATCO Gas (North)		6,094	Note 3
ATCO Pipelines (North)		2,111	Note 3

Note 1: As filed in General Rate Application 2000-350 and subject to the Board's determination.

Note 2: As filed in General Rate Application 2000-365 and subject to the Board's determination.

Note 3: These Balances are provided for information purposes only.

APPENDIX 4 – SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

9. Further, the Board directs AU, in its Refiling, to attach an updated version of Exhibit 02-038 (Appendix 2 attached hereto) which shall supplement the existing document by the addition of the amounts established in substitution for the placeholders by this Decision. 29

May 19, 2006

Via EAS

EX 02-038 AU's Revised Response to Board Exhibit 30-006
2006-05-19

Alberta Energy and Utilities Board
640 – 5 Avenue S.W.
Calgary, Alberta
T2P 3G4

Attention: Ms. Lisa Kelly
Application Officer

Dear Ms. Kelly:

Re: ATCO Utilities 2005 – 2007 Common Matters Filing
Application No. 1407946
Revised Response to Board Exhibit 30-006

Attached please find the Revised ATCO Utilities' response to the Board's Exhibit 30-006 – Placeholder and Revenue Requirement Summary.

This attachment replaces the Summary filed as Exhibit 02-037 on May 19, 2006.

Yours truly,

Original Signed by W. James Beckett

W. JAMES BECKETT, P. ENG.
EXECUTIVE VICE PRESIDENT, REGULATORY

WJB/pc
Att.
2006-05-19_AU__Revised_Response_Board_EX-30-006_EX-02-038.doc

ATCO Utilities 2005-2007 Common Matters
Application No. 1407946

ATCO Utilities Placeholder and Revenue Requirement Summary

Exhibit No. 30-06
(Revised)

- Please include and reference all applicable Board Decisions including adjustments from Decision 2006-004 and Decision 2006-024.
- Please break out revenue requirement adjustment and current placeholders, if any, by type of pension expense (i.e. deferred pension asset, supplemental pension plan, return on net pension asset and other as required).

Note: ATCO Gas amounts applied for in this application as shown below include the impact of the change in working capital based on the weighted average cost of capital as included in the 2005-2007 GRA filing. These amounts will need to be updated once the final weighted average cost of capital for those test years is known.

Pension

Applied for Amount in the Respective Revenue Requirements:

($000)	2005 Trans.	2005 Dist.	2005 Total	2006 Trans.	2006 Dist.	2006 Total	2007 Trans.	2007 Dist.	2007 Total
Deferred Asset Amort[1]									
ATCO Electric	90	260	350	83	245	328	N/A	N/A	N/A
Suppl. Pension & OPEB[2]									
ATCO Electric	210	500	710	210	490	700	N/A	N/A	N/A
Deferred Asset Amort[1]									
ATCO Gas (North)			642			577			511
ATCO Gas (South)			1050			941			836
Suppl. Pension & OPEB[3]									
ATCO Gas (North)			701			722			743
ATCO Gas (South)			590			607			624
ATCO Pipelines			N/A			N/A			N/A

[1] 2005-2007 Common Matters Application 1407946 Section 6-3, 6-4
[2] These amounts are different than the Company Pension totals disclosed in Schedule 2-1 of ATCO Electric's Response to issues raised at the June 20th workshop filed with the Board July 8, 2006 due to the impact of amounts included in capital.
[3] 2005-2007 ATCO Gas GRA Application 1400690 Table 4.3.30

ATCO Utilities 2005-2007 Common Matters
Application No. 1407946

ATCO Utilities Placeholder and Revenue Requirement Summary

Exhibit No. 30-06
(Revised)

Current Placeholders:

($000)	2005 Trans.	2005 Dist.	2005 Total	2006 Trans.	2006 Dist.	2006 Total	2007 Trans.	2007 Dist.	2007 Total
Deferred Asset Amort:									
ATCO Electric[1]	< 30>	<100>	<130>	<100>	<280>	<380>	N/A	N/A	N/A
Suppl. Pension & OPEB[2]									
ATCO Electric	210	500	710	210	490	700	N/A	N/A	N/A
Deferred Asset Amort:									
ATCO Gas (North)			-			-			-
ATCO Gas (South)			-			-			-
Suppl. Pension & OPEB[2]									
ATCO Gas (North)			701			722			743
ATCO Gas (South)			590			607			624
ATCO Pipelines			N/A			N/A			N/A

(1) ATCO Electric 2005-2006 GTA April 28, 2006 Refiling, Board Direction No. 43
(2) Compliance Filing Application 1452948 to Decision 2006-004, Placeholder Summary Pages 1-3

ATCO Utilities 2005-2007 Common Matters
Application No. 1407946

ATCO Utilities Placeholder and Revenue Requirement Summary
Exhibit No. 30-06
(Revised)

- Please include and reference all applicable Board Decisions including adjustments from Decision 2006-004 and Decision 2006-024.
- Please note the average square footage amounts for each of the ATCO Utilities.

Rent Expense

Applied for Amounts in the Respective Revenue Requirements:

($000)	2003 Trans.	2003 Dist.	2003 Total	2004 Trans.	2004 Dist.	2004 Total
ATCO Electric	550 (2)	673 (2)	1,223(1)	551 (2)	674 (2)	1,225(1)

(1)2005-2007 Common Matters Application 1407946 Section 3 page 3 of 3
(2)The % split for 2003 and 2004 was indicated in Schedule 27-B-2 of the 2005-2006 GTA.

($000)	2005 Trans.	2005 Dist.	2005 Total	2006 Trans.	2006 Dist.	2006 Total	2007 Trans.	2007 Dist.	2007 Total
ATCO Electric (1)	710 (2)	867 (2)	1,577 (1)	710 (2)	867 (2)	1,577 (1)	N/A	N/A	N/A
ATCO Gas (North)			791			791			791
ATCO Gas (South)			755			755			755
ATCO Pipelines			N/A			N/A			N/A

(1)2005-2007 Common Matters Application 1407946 Section 3 page 3 of 3
(2)ATCO Electric 2005-2006 GTA April 28, 2006 Refiling, Board Direction No. 43. The Transmission/Distribution split % was provided on Schedule 27-B-2 of the Application.

Average Square Footage:

($000)	2005 Trans.	2005 Dist.	2005 Total	2006 Trans.	2006 Dist.	2006 Total	2007 Trans.	2007 Dist.	2007 Total
ATCO Electric			93,036			93,036			N/A
ATCO Gas			91,226			91,226			91,226
ATCO Pipelines			N/A			N/A			N/A

ATCO Utilities 2005-2007 Common Matters
Application No. 1407946

ATCO Utilities Placeholder and Revenue Requirement Summary

Exhibit No. 30-06
(Revised)

Current Placeholders:

($000)	2003 Trans.	2003 Dist.	2003 Total	2004 Trans.	2004 Dist.	2004 Total
ATCO Electric* (1)	550 (2)	673 (2)	1,223 (1)	551 (2)	674 (2)	1,225 (1)

ATCO Electric	2003	2004
Square Footage	92,009	92,260

(1) 2005-2007 Common Matters Application 1407946 Section 3 page 3 of 3
(2) ATCO Electric 2005-2006 GTA April 28, 2006 Refiling, Board Direction No. 43. The Transmission/Distribution split % was provided on Schedule 27-B-2 of the Application.

($000)	2005 Trans.	2005 Dist.	2005 Total	2006 Trans.	2006 Dist.	2006 Total	2007 Trans.	2007 Dist.	2007 Total
ATCO Electric(1)	710	870	1,580	710	870	1,580			
ATCO Gas (North)(2)			630			644			658
ATCO Gas (South)(2)			633			647			661
ATCO Pipelines									

(1) Compliance Filing Application 1458743 to Decision 2006-024, Placeholder and other Outstanding Matters Summary Pages 1 of 1.
(2) Compliance Filing Application 1452948 to Decision 2006-004, Placeholder Summary Pages 1-3. Represents rent expense account 721 revised placeholders.

ATCO Utilities 2005-2007 Common Matters
Application No. 1407946

ATCO Utilities Placeholder and Revenue Requirement Summary
Exhibit No. 30-06
(Revised)

Please include and reference all applicable Board Decisions including adjustments from Decision 2006-004 and Decision 2006-024.

Note: Amounts shown below do not include the income tax effect.

Preferred Share Amount

Applied For and Current Placeholder Amounts:

ATCO Electric ($000)	2005 Trans.	2005 Dist.	2005 Total	2006 Trans.	2006 Dist.	2006 Total
Mid Year Preferred Amount (1)	50,100	43,300	93,400	50,100	43,300	93,400
Return on Preferred Shares (2)	2,610	2,140	4,750	2,600	2,150	4,750

(1)Per ATCO Electric 2005-2006 GTA. Schedule 29-B-1

(2)Per ATCO Electric 2005-2006 GTA April 28, 2006 Refiling, Board Direction No. 43

Applied For and Current Placeholder Amounts:

ATCO Gas North ($000)	2005	2006	2007
Mid Year Preferred Amount	36,584	36,584	36,584
Return on Preferred Shares	1,986	1,992	1,999

* Compliance Filing Application 1452948 to Decision 2006-004, Sched 3.1A, line 10 (North)

Applied For and Current Placeholder Amounts

ATCO Gas South ($000)	2005	2006	2007
Mid Year Preferred Amount	29,157	29,157	29,157
Return of Preferred Shares	1,585	1,592	1,599

* Compliance Filing Application 1452948 to Decision 2006-004, Sched 3.1B, line 10 (South)

Executive Compensation

Please show for each ATCO Utility, all compensation and benefit amounts including incentive pay forecast for operating and capital accounts for each of (a) utility executives, (b) office of the Chairman of the Board and (c) the corporate office.

Note: Amounts shown below include Directors fees as shown in Appendix 4.5 of the application.

Applied for Amounts in the Respective Revenue Requirements:

($000)	2005 Trans.	2005 Dist.	2005 Total	2006 Trans.	2006 Dist.	2006 Total	2007 Trans.	2007 Dist.	2007 Total
ATCO Electric (1)	895.9	1326	2221.9	920.1	1362.3	2282.4	N/A	N/A	N/A
Utility Executive Compensa									
ATCO Gas (North) (2)			937			960			985
ATCO Gas (South)			936			960			984
Corporate Office:									
ATCO Gas (North) (3)			482			498			511
ATCO Gas (South)			523			540			556
ATCO Pipelines			N/A			N/A			N/A

(1)See attached schedule
(2)2005-2007 Common Matters Application 1407946 Appendix 4.5
(3)2005-2007 Common Matters Application 1407946, Appendix 4.5

ATCO Utilities 2005-2007 Common Matters
Application No. 1407946

ATCO Utilities Placeholder and Revenue Requirement Summary

Exhibit No. 30-06
(Revised)

Current Placeholders:

($000)	2005 Trans.	2005 Dist.	2005 Total	2006 Trans.	2006 Dist.	2006 Total	2007 Trans.	2007 Dist.	2007 Total
ATCO Electric	895.9	1326	2221.9	920.1	1362.3	2282.4	N/A	N/A	N/A
Utility Executive Compensa									
ATCO Gas (North)(1)			516			528			538
ATCO Gas (South)			516			527			538
Corporate Office:									
ATCO Gas (North)(2)			482			498			511
ATCO Gas (South)			523			540			556
ATCO Pipelines*			N/A			N/A			N/A

(1) ATCO Gas Compliance Filing March 17, 2006 Placeholder Summary Page 2 & 3
(2) 2005-2007 Common Matters Application 1407946, Appendix 4.5

Applied For and Current Placeholders:

($000)	2003 North	2003 South	2003 Total	2004 North	2004 South	2004 Total
ATCO Pipelines(1)	267	75	342	276	77	353

(1) Reference: Decision 2004-059, pages 16 and 17

ATCO Pipelines

Please confirm what ATCO Pipelines is seeking from the Board in this Application in respect of Pension, Rent Expense, Executive Compensation and Preferred Shares matters and if ATCO Pipelines is seeking the replacement of any placeholders.

Response: ATCO Pipelines requests that the Board approve amounts for Executive Compensation for its 2003 and 2004 revenue requirement. Any changes to the 2003 and 2004 placeholders for this matter will be incorporated into the next GRA for ATCO Pipelines. In addition, the Board's ruling on all Common Matters will be incorporated into the forecasts for the test years of ATCO Pipelines next GRA.

ATCO Utilities 2005-2007 Common Matters
Application No. 1407946

ATCO Utilities Placeholder and Revenue Requirement Summary

Exhibit No. 30-06
(Revised)

Executive Compensation – Attachment

ATCO Electric

($000)	2005 Trans.	2005 Dist.	2005 Total	2006 Trans.	2006 Dist.	2006 Total
1 (a) Utility Executive Compensation						
2 O&M	318	621	939	327	637	964
3 G&A	105	129	234	106	129	235
4 Capital	72	88	160	74	91	165
5 Capital Impact on Revenue Requirement*	6.9	8.0	14.9	7.1	8.3	15.4
6 Total Impact on Revenue Requirement (L2 + L3 + L5)	429.9	758	1,187.9	440.1	774.3	1,214.4

*Based on capital cost multiplied by the before tax return on rate base provided in Attachment 7 for Board Direction No. 43 of the ATCO Electric 2005-2006 GTA April 28, 2006 Refiling (9.53% for 2005 and 9.11% for 2006).

	2005 Trans.	2005 Dist.	2005 Total	2006 Trans.	2006 Dist.	2006 Total
(b) Office of the Chairman – Executive Compensation						
Head Office	324	395	719	334	408	742
Directors' Fees						
ATCO Electric	14	17	31	14	18	32
Head Office	128	156	284	132	162	294

	2005 Trans.	2005 Dist.	2005 Total	2006 Trans.	2006 Dist.	2006 Total
(c) Total Executive Compensation including Directors Fees	895.9	1,326	2,221.9	920.1	1,362.3	2,282.4

Attachment 92.1

INVESTOR GROWTH EXPECTATIONS

Summer 2004

A study done by Vander Weide and Carleton in 1988[1] suggests that consensus analysts' forecast of future growth is superior to historically oriented growth measures in stock valuation process for domestic companies. We worked with one of the original authors of the study, Dr. James H. Vander Weide, and closely followed his suggestions and methodology to investigate whether the results still hold in more recent times (2001- 2003).

We used the following equation to determine which estimate of future growth (g) best predicts the firm's P/E ratio when combined with the dividend payout ratio, D/E, and risk variables, B, Cov, Stb, and Sa.

$$P/E = a_0(D/E) + a_1 g(\text{Growth}) + a_2 B(\text{Beta}) + a_3 Cov(\text{Interest Coverage Ratio}) + a_4 Stb(\text{Stability}) + a_5 Sa(\text{Std Dev}) + e$$

Data Description

Earnings Per Share: IBES consensus analyst estimate of the firm's earnings for the unreported year.

Price/Earnings Ratio: Closing stock price for the year divided by the consensus analyst earnings per share for the forthcoming year.

Dividends: Ratio of common dividends per share to the consensus analyst earnings forecast for the forthcoming fiscal year (D/E).

Historical Growth measures

- EPS Growth Rate: Determined by a log-linear least squares regression for the latest year, two years, three years, …, and ten years.
- Dividend per Share Growth Rate: Determined by a log-linear least squares regression for the latest year, two years, three years, …, and ten years.
- Book Value per Share Growth Rate: Common equity divided by the common shares outstanding. Determined by a log-linear least squares regression for the latest year, two years, three years, …, and ten years.
- Cash Flow per Share Growth Rate: Ratio of gross cash flow to common shares outstanding. Determined by a log-linear least squares regression for the latest year, two years, three years, …, and ten years.
- Plowback Growth: Firm's retention ratio for the current year times the firm's latest annual return on equity.
- 3yr Plowback Growth: Firm's three-year average retention ratio times the firm's three-year average return on equity.

Consensus Analysts' Forecasts

- Five-Year Earnings Per Share Growth: Mean analysts' forecast compiled by IBES.

[1] Vander Weide, J. H., and W. T. Carleton. "Investor Growth Expectations: Analysts vs. History." *The Journal of Portfolio Management*, Spring 1988, pp. 78-82.

Risk Variables

B: Beta, the firm's beta versus NYSE from Value Line.

Cov: The firm's pretax interest coverage ratio from Compustat.

Stb: Five-year historical earnings per share stability. Average absolute percentage difference between actual reported EPS and a 5yr historical EPS growth trend line from IBES.

Sa: The standard deviation of earnings per share estimate for the fiscal year from IBES.

We set five restrictions on the companies included in the study in order to be consistent with the original study and to obtain more meaningful results.

- Excluded all firms that IBES did not follow.
- Eliminated companies with:
  - Negative EPS during any of the years 1991-2003.
  - No dividend during any one of the years 1991-2003.
  - P/E ratio greater than 60 in years 2001-2003.
  - Less than five years of operating history.

The final universe consisted of 411 US firms, fifty-nine of which are utility companies.

Results

The study was performed in two stages.

Stage 1

In order to determine which historically oriented growth measure is most highly correlated with each firm's end-of-year P/E ratio, we computed spearman (rank) correlations between all forty-two historically oriented future growth measures and P/E.

The result of the stage 1 study is displayed in Table 1. Three-year plowback ratio has the highest correlation with P/E in 2001 and 2002, and five-year EPS growth rate has the highest correlation with P/E in 2003.

Table 1

Stage1 Results for Utility and Non-Utility Companies Combined

Correlations between Historically Based Growth Estimates by Year with P/E

Current Year		y1	y2	y3	y4	y5	y6	y7	y8	y9	y10
2001	EPS	0.232	0.210	0.145	0.122	0.059	0.034	-0.007	-0.076	-0.117	-0.154
	DPS	-0.243	-0.297	-0.296	-0.293	-0.313	-0.316	-0.336	-0.334	-0.329	-0.333
	BVPS	0.059	-0.017	-0.098	-0.138	-0.150	-0.182	-0.219	-0.259	-0.271	-0.273
	CFPS	0.092	0.092	0.087	0.042	-0.063	-0.102	-0.141	-0.193	-0.237	-0.262
	plowback	0.203									
	plowback3	0.308									
2002	EPS	-0.007	0.147	0.076	0.080	0.083	0.050	0.030	-0.018	-0.060	-0.089
	DPS	-0.126	-0.202	-0.251	-0.224	-0.215	-0.239	-0.232	-0.233	-0.211	-0.198
	BVPS	-0.036	-0.036	-0.078	-0.115	-0.114	-0.127	-0.152	-0.162	-0.175	-0.171
	CFPS	0.056	0.045	0.017	0.021	0.030	-0.024	-0.050	-0.080	-0.125	-0.162
	plowback	0.093									
	plowback3	0.180									
2003	EPS	0.073	0.084	0.214	0.231	0.244	0.228	0.182	0.158	0.104	0.049
	DPS	0.120	0.054	-0.001	-0.078	-0.090	-0.126	-0.152	-0.165	-0.183	-0.185
	BVPS	0.097	0.076	0.067	0.036	-0.045	-0.062	-0.063	-0.083	-0.105	-0.131
	CFPS	0.146	0.196	0.243	0.239	0.206	0.178	0.107	0.089	0.039	-0.022
	plowback	-0.017									
	plowback3	0.038									

We also independently examined utility and non-utility firms. Table 2 shows the result for the fifty-nine utility firms. Two-year growth in EPS has the highest correlation with P/E in 2001, four-year EPS has the highest correlation in 2002, and six-year EPS has the highest correlation in 2003.

Table 3 exhibits the result for the remaining non-utility firms. EPS one-year growth, two-year growth, and five-year growth has the highest correlation with P/E in 2001, 2002, and 2003, respectively.

Table 2

Stage1 Results for Utility Companies

Correlations between Historically Based Growth Estimates by Year with P/E

Current Year		y1	y2	y3	y4	y5	y6	y7	y8	y9	y10
2001	EPS	0.305	0.330	0.305	0.319	0.238	0.157	0.129	0.107	0.079	0.048
	DPS	-0.215	-0.321	-0.302	-0.294	-0.316	-0.281	-0.332	-0.414	-0.435	-0.429
	BVPS	0.164	0.137	0.147	-0.027	-0.072	-0.135	-0.117	-0.104	-0.106	-0.140
	CFPS	0.194	0.135	0.020	-0.018	-0.122	-0.157	-0.135	-0.134	-0.103	-0.219
	plowback	-0.143									
	plowback3	-0.027									
2002	EPS	-0.065	0.044	0.069	0.119	0.071	0.004	-0.038	-0.069	-0.061	-0.070
	DPS	-0.333	-0.327	-0.278	-0.313	-0.280	-0.321	-0.277	-0.226	-0.203	-0.210
	BVPS	-0.325	-0.239	-0.182	-0.177	-0.230	-0.237	-0.250	-0.247	-0.235	-0.235
	CFPS	-0.205	-0.132	-0.172	-0.166	-0.216	-0.289	-0.285	-0.265	-0.227	-0.218
	plowback	-0.151									
	plowback3	-0.133									
2003	EPS	0.010	0.136	0.186	0.263	0.365	0.367	0.344	0.343	0.309	0.302
	DPS	0.151	-0.029	-0.014	-0.022	-0.054	-0.117	-0.142	-0.137	-0.105	-0.092
	BVPS	0.212	0.060	0.047	0.019	0.003	0.040	0.022	0.005	0.003	-0.002
	CFPS	0.222	-0.046	0.173	0.115	0.165	0.100	0.017	0.077	0.057	0.077
	plowback	-0.365									
	plowback3	-0.403									

Table 3

Stage1 Results for Non-Utility Companies

Correlations between Historically Based Growth Estimates by Year with P/E

Current Year		y1	y2	y3	y4	y5	y6	y7	y8	y9	y10
2001	EPS	0.1843	0.1660	0.1293	0.1218	0.0873	0.0829	0.0618	0.0106	-0.0194	-0.0412
	DPS	-0.2036	-0.2211	-0.2042	-0.1935	-0.2098	-0.2066	-0.2186	-0.2155	-0.2046	-0.1975
	BVPS	0.0757	0.0084	-0.0791	-0.0997	-0.0916	-0.1146	-0.1388	-0.1783	-0.1866	-0.1823
	CFPS	0.0864	0.0710	0.0956	0.0704	-0.0033	-0.0162	-0.0366	-0.0747	-0.1186	-0.1325
	plowback	0.0781									
	plowback3	0.1781									
2002	EPS	0.0762	0.1767	0.0755	0.0817	0.0936	0.0757	0.0708	0.0316	-0.0011	-0.0254
	DPS	-0.0804	-0.1693	-0.2103	-0.1672	-0.1519	-0.1720	-0.1645	-0.1636	-0.1394	-0.1226
	BVPS	0.0527	0.0236	-0.0363	-0.0777	-0.0710	-0.0753	-0.0953	-0.1019	-0.1118	-0.1061
	CFPS	0.0905	0.0488	0.0143	0.0237	0.0563	0.0246	0.0097	-0.0079	-0.0458	-0.0821
	plowback	0.0634									
	plowback3	0.1306									
2003	EPS	0.1254	0.1783	0.2788	0.2689	0.2791	0.2622	0.2219	0.2039	0.1559	0.1090
	DPS	0.1810	0.1290	0.0655	-0.0128	-0.0101	-0.0400	-0.0630	-0.0772	-0.0930	-0.0952
	BVPS	0.1555	0.1740	0.1534	0.1056	0.0127	-0.0069	-0.0054	-0.0218	-0.0416	-0.0636
	CFPS	0.1479	0.2200	0.2512	0.2429	0.2004	0.1839	0.1349	0.1286	0.0892	0.0388
	plowback	-0.1109									
	plowback3	-0.0402									

Stage 2
We compared the multiple regression model of historical growth rate with the highest correlation to the P/E ratio from stage 1 to the five-year earnings per share growth forecast.

$$P/E = a_0(D/E) + a_1 g + a_2 B + a_3 Cov + a_4 Stb + a_5 Sa + e$$

The regression results are displayed in table 4. The results show that the consensus analysts' forecast of future growth better approximates the firm's P/E ratio, which is consistent with the results found by Vander Weide and Carleton. In both regressions, R^2 in the regression with the consensus analysts' forecast is higher than the R^2 in the regression with the historical growth.

Table 4
Stage2 Results for Utility and Non-Utility Companies Combined
Multiple Regression Results
P/E = a0 + a1 **D/E** + a2 **g** + a3 **B** + a4 **Cov** + a5 **Stb** + a6 **Sa**

Historical

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	10.43	8.46	10.79	6.79	0.02	-0.03	-18.83	0.20	13.90
	4.73	5.53	2.93	3.54	3.05	-3.06	-3.32		
2002	12.36	7.60	6.66	1.01	0.00	0.01	-32.48	0.15	9.46
	7.21	6.18	2.61	0.66	1.57	1.48	-4.04		
2003	13.34	5.96	9.87	5.27	0.01	-0.01	-20.46	0.24	17.61
	7.29	4.04	2.95	3.39	3.62	-1.31	-4.25		

Analysts' Forecasts

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	-1.26	16.14	144.75	-0.64	0.01	-0.03	-10.76	0.47	48.00
	-0.62	11.63	13.22	-0.38	3.07	-4.04	-2.29		
2002	3.37	13.37	106.07	-3.60	0.00	0.01	-21.85	0.35	29.73
	1.93	10.97	10.59	-2.57	1.25	1.50	-3.06		
2003	4.77	12.76	61.93	4.38	0.01	0.00	-19.41	0.33	26.38
	2.65	9.48	7.25	3.01	2.45	-0.81	-4.33		

*T-stats below the coefficients in smaller font

For utility companies shown in table 5, consensus analysts' forecast of future growth is superior to historically oriented growth in 2002 and 2003. R^2 is lower in the regression with the consensus analysts' forecast in 2001. For non-utility companies, we found that consensus analysts' forecast of future growth is superior to the alternative in all three years (table 6).

Table 5
Stage2 Results for Utility Companies
Multiple Regression Results
P/E = a0 + a1 **D/E** + a2 **g** + a3 **B** + a4 **Cov** + a5 **Stb** + a6 **Sa**

Historical

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	7.90	11.07	-11.19	-3.00	0.29	0.00	-9.37	0.44	6.38
	2.16	4.80	-5.71	-0.86	0.88	0.64	-1.51		
2002	13.87	7.00	-3.80	-6.89	0.56	0.00	-29.89	0.38	5.11
	4.02	3.54	-0.66	-2.01	1.48	0.42	-2.70		
2003	11.29	7.74	-1.65	-1.40	0.32	0.00	-5.69	0.25	2.68
	3.22	3.30	-0.23	-0.43	1.05	-0.73	-0.75		

Analysts' Forecasts

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	9.61	9.20	66.61	-7.92	0.50	-0.01	-12.83	0.27	2.95
	2.31	3.45	3.66	-1.86	1.31	-1.33	-1.76		
2002	12.43	7.86	50.74	-9.61	0.50	0.00	-24.94	0.48	7.56
	3.89	5.29	3.10	-2.94	1.50	0.17	-2.41		
2003	5.81	11.06	101.12	-1.69	-0.19	0.00	-4.75	0.50	7.81
	1.89	6.32	4.80	-0.58	-0.74	-0.22	-0.74		

*T-stats below the coefficients in smaller font

Table 6
Stage2 Results for Non-Utility Companies
Multiple Regression Results
P/E = a0 + a1 **D/E** + a2 **g** + a3 **B** + a4 **Cov** + a5 **Stb** + a6 **Sa**

Historical

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	15.90	8.39	2.82	3.53	0.02	-0.03	-21.05	0.21	12.45
	6.57	4.13	1.96	1.68	2.97	-2.14	-3.40		
2002	17.76	8.46	6.02	-3.06	0.00	0.02	-36.97	0.27	16.78
	9.39	5.19	3.28	-1.88	1.37	2.52	-4.31		
2003	14.24	9.86	8.85	3.46	0.01	0.00	-19.00	0.30	19.89
	7.49	5.89	2.49	2.11	3.23	-0.15	-3.73		

Analysts' Forecasts

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	-0.51	17.28	140.84	-1.06	0.01	-0.03	-8.63	0.44	36.00
	-0.22	11.21	10.73	-0.59	2.88	-2.62	-1.63		
2002	5.05	15.67	91.22	-4.06	0.00	0.02	-22.93	0.38	27.65
	2.48	11.23	7.66	-2.74	1.18	2.33	-2.87		
2003	7.25	14.47	45.60	3.47	0.01	0.00	-19.09	0.33	22.30
	3.56	9.42	4.68	2.20	2.36	-0.12	-3.89		

*T-stats below the coefficients in smaller font

Attachment 126.1

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Attachment 135.1

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