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December 18, 2015

Via Email
Original via Mail

Association of Major Power Customers of BC
c/o Bull, Housser & Tupper LLP
1800 – 510 West Georgia Street
Vancouver, BC V6B 0M3

Attention: Mr. Matthew Keen

Dear Mr. Keen:

Re: FortisBC Energy Inc. (FEI)

Application for its Common Equity Component and Return on Equity (ROE) for 2016 (the Application)

Response to the Association of Major Power Customers of BC (AMPC) Information Request (IR) No. 1 to Mr. James Coyne, Concentric Energy Advisors Inc. (Concentric)

On October 2, 2015, FEI filed the Application referenced above. In accordance with Commission Order G-177-15 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to AMPC-Concentric IR No. 1 from Mr. Coyne of Concentric.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)

First Topic: Concentric Evidence and Previous Testimony

Reference: Exhibit B-1, Appendix B, Mr. Coyne's evidence page 2 to page 7

Preamble:

Mr. Coyne indicates his qualifications at Concentric and the basis for his recommendation

Question 1:

1.1 Please confirm that previously, for example before the Alberta Utilities Commission, Mr. Coyne has filed testimony with Mr. Stephen Gaske also of Concentric and that they are both senior members of Concentric providing fair rate of return testimony

Response:

Confirmed. In Alberta, Mr. Coyne and Dr. Gaske filed testimony in the same proceeding, and served on the same panel in the 2008 Generic Cost of Capital proceeding. Mr. Coyne testified on business risk and ROE, and Dr. Gaske testified on capital structure. (Alberta Utilities Commission, 2009 Generic Cost of Capital Proceeding, Application No. 1578571 / Proceeding ID. 85).

1.2 Please confirm that Mr. Gaske filed testimony before the Régie in a recent intervention on behalf of Intragaz Limited Partnership (R-3807-2012) and that Mr. Gaske recommended an 11.50% fair ROE based on the ***median*** ROE of a proxy group of Canadian utilities ***supported by*** the DCF results from a proxy group of US utilities (page 5).

Response:

Mr. Coyne was not involved in this proceeding, and did not familiarize himself with Dr. Gaske's evidence, but has no reason to doubt the citation.

1.3 Please confirm that in recent testimony before the Régie for Hydro Quebec Transmission and Distribution (R- 3842-2013) Mr. Coyne used the same sample as Mr. Gaske except for the addition of Valener, but that he based his estimate on the ***mean*** rather than the median ROE.

Response:

Mr. Coyne's evidence on behalf of Hydro Quebec TransÉnergie and Hydro Quebec Distribution is attached. The Canadian and U.S. proxy groups that Mr. Coyne relied upon are shown on pages 23-25 of that testimony. The results shown in Table 1 on page 10 are based on average (mean) ROE estimates. Mr. Coyne has not compared his analysis or proxy groups to those of Dr. Gaske in Intragaz, but has no reason to doubt the citation. Please also refer to the response to AMPC-Concentric IR 1.1.6 on this topic.

1.4 Please confirm that in his HQT and HQD evidence Mr. Coyne placed principal weight on the US sample estimates, whereas Mr. Gaske placed primary emphasis on the Canadian sample's estimates?

Response:

Mr. Coyne confirms that in his evidence on behalf of HQT and HQD, he gave more weight to the results for the proxy group of U.S. electric utilities because Mr. Coyne determined that the companies in the U.S. proxy group were more risk comparable to HQT and HQD than were the companies in the Canadian proxy group. Mr. Coyne has not compared his weighting to Dr. Gaske's in Intragaz.

1.5 Please confirm that in his current evidence in this proceeding Mr. Coyne places **equal** weight on US and Canadian estimates (page 5).

Response:

Confirmed. See pages 5-6 of Mr. Coyne evidence for the rationale supporting his decision to place equal weight on the Canadian and U.S. estimates.

1.6 Please explain in detail why Concentric witnesses would switch between using averages (means) and medians and why they have been inconsistent in their emphasis on US versus Canadian estimates over the last three years? If Concentric feels there is no inconsistency please clarify.

<u>Response:</u>

Mr. Coyne cannot speak for the methodology used by other cost of capital witnesses. Mr. Coyne has been consistent in his reliance on mean results from the various financial models used to estimate the cost of equity. Mr. Coyne presumes that Dr. Gaske may have been influenced by FERC's preference for the use of medians in deriving cost of capital estimates for interstate gas pipelines and electric transmission. Mr. Coyne has consistently testified that it is reasonable to establish the ROE recommendation for a Canadian electric or natural gas utility based on the results for both Canadian and U.S. proxy groups. Mr. Coyne has consistently observed that there are very few publicly traded utilities in Canada, making it difficult to rely exclusively on a Canadian comparator group. Mr. Coyne has also consistently indicated that it is possible to select a group of risk comparable U.S. utilities to estimate the cost of equity for a Canadian electric or gas utility. Further, Mr. Coyne has provided evidence that the business risk and the regulatory environment for utilities in the U.S. is very similar to the business risk and regulatory environment faced by utilities in Canada. Finally, in recent years, several utility holding companies in Canada have acquired electric and gas operating utilities in the U.S., lending support to the notion that an integrated North American proxy group is appropriate.

Mr. Coyne has not provided an integrated North American proxy group in his FEI testimony because only one Canadian company, Valener, would have satisfied the proxy group screening criteria as a regulated gas distribution company. Though Mr. Coyne believes that a North American proxy group containing only one Canadian company would still have produced a fair ROE estimate for FEI, in Mr. Coyne's opinion, Mr. Coyne has allowed equal weighting of his U.S. and Canadian proxy group results to afford as much of a Canadian perspective as Mr. Coyne determines is appropriate, given the limitations of the Canadian proxy group companies in terms of comparability to FEI.

Second Topic: Business and Economic Conditions in the US and Canada

Reference: Exhibit B-1, Appendix B, Mr. Coyne's evidence page 14-28

Preamble:

Mr. Coyne discusses current conditions.

Question 2:

2.1 Mr. Coyne discusses the change in recent market conditions. Please provide a table with the average values for GDP growth, inflation, the long Canada bond yield, the credit spread for A issuers, the level of the TSX composite index and the yield spread (long Canada minus 91 day Treasury Bill yield) as of October 2012 and October 2015.

Response:

Mr. Coyne has provided 2012 as of the end of the year and 2015 data is as of November 30, 2015. See table below:

	Canada Real GDP Growth	**Canada Consumer Price Index**	**30-Year Canada Gov't Bond**	**Canadian Corporate Utility A Index**	**Spread: Corp Utility A Index to 30-year Canada Gov't Bond**	**SPTSX Index**	**3-Month Canada Gov't Bond**	**Spread: 30-year Canada Gov't Bond to 3 Month Canada Gov't Bond**
2012	1.80	1.50	2.36	3.82	1.46	12290.25	0.95	1.41
2015	2.3 [2]	1.0 [2]	2.35	4.17	1.82	13424.19	0.45	1.90
Notes:								
(1) All data for 2015 are as of November 30, except as otherwise noted. (2) Through Sept 30, 2015 per National Bank of Canada.								

2.2 Please fully explain what Mr. Coyne means by "stalled" Chinese growth (page 14). Is it his judgement that Chinese economy has plateaued with no growth?

Response:

No, but growth has slowed considerably. Mr. Coyne is referring to the July 2015 downturn in China's factory activity which has sent ripple effects throughout the global economy. China is the second largest world economy and experienced a weakening in manufacturing in July, 2015 when the Chinese economy moved from expansion to contraction. The weakening is primarily attributable to weak demand overseas and at home, a battered property sector and added pressure from a swooning stock market.[1] There was a subsequent surprise devaluation of the Yuan on August 11, 2015. World stocks reacted later in August prompted by fears of the health of China's economy. These concerns over China's economic slowdown have continued throughout the Fall, and in December, 2015 China exports fell for a 5th straight month, and imports fell for a 13th consecutive month. Clearly, China's economy has slowed, though government sponsored investment is expected to continue to support the economy through this downturn. The stall in Chinese growth is impacted by weak demand overseas and as global economies strengthen, Mr. Coyne would expect China's economy to strengthen as well.

2.3 Please fully explain how the Canadian economy benefits from a strong US $. Does Mr. Coyne mean a weak Canadian $ (page 15) or that both currencies are strong?

Response:

The Canadian economy benefits from a strong U.S. dollar by exporting resources to the U.S. (Canada's largest trading partner) where the U.S. dollar has greater purchasing power than the Canadian dollar at present. Exports are a significant driver of the Canadian economy and benefit by the positive difference between the U.S. and the Canadian dollar. As pointed out in the June 20, 2015 Economic Commentary by the Alberta Government, "Since mid-year 2014 the Canadian dollar has lost about 15% against the U.S. dollar. This would translate into an 18% gain for Alberta exports that are priced in U.S. dollars and will allow other exporters that price their products in Canadian dollars to become more competitive and sell more product into the U.S." Consensus Forecasts estimates that Canada has technically ended its recession with positive economic growth for the 3rd and 4th quarters of 2015, following the declines in Q1 and Q2, primarily due to greater exports due to the weakness in the Canadian dollar and firm U.S. growth.[2]

2.4 Please provide the current and the relied on Blue Chip and Consensus Economics periodicals (page 17).

[1] Kazer, William, Wall Street Journal, *China Manufacturing Growth Stalls* (July 2015)
[2] Consensus Forecasts Survey Date (December 7, 2015) p. 17

Response:

Please refer to Attachment 2.4.

2.5 Please provide the support for the statement that in 2012 "the economy" had begun to recover from the global financial crisis. Is this meant to refer to the US or Canadian economies? If Canada, when does Mr. Coyne estimate that all the Canadian jobs lost in the recession were recovered? Please explain how the external factors listed by the Bank of Canada at that time affect whether or not Canada had recovered?

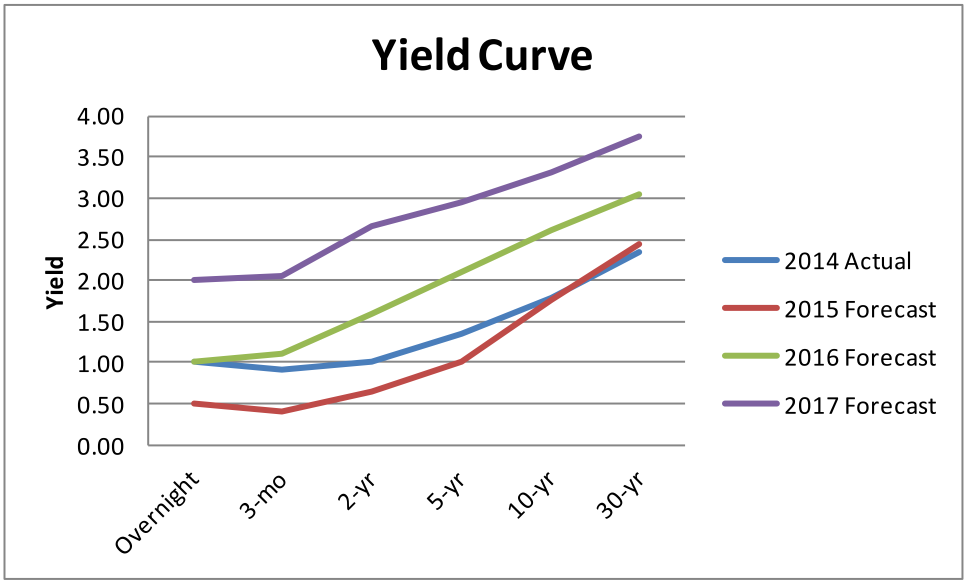
Response:

Mr. Coyne is referring to the Canadian economy at the time evidence was developed for the August 2012, Stage 1 GCOC proceeding, in the referenced statement. As shown on Exhibit JMC-2, real GDP growth in Canada and the U.S. resumed in 2010, although economic growth in both countries remained weaker than normal after the financial crisis. Similarly, the unemployment rate in Canada had fallen to 6.3 percent in 2012 from its height of 7.3 percent in 2009. Mr. Coyne has not estimated when all the Canadian jobs lost in the recession were recovered, nor does his statement imply that Canada has completed its recovery or that all jobs lost have been recovered. He notes that Exhibit JMC-1 shows that unemployment levels in Canada have remained above those prior to the recession, but that is not a measure of the absolute number of jobs. Mr. Coyne has not conducted an in-depth analysis of how the external factors listed by the Bank of Canada at that time have affected whether or not Canada has recovered, although he notes that the Bank of Canada continues to list stalled growth in the euro area and China as continuing to hamper the Canadian economic recovery.

2.6 Please provide any support for the idea that a steeper yield spread (long Canada minus Treasury Bill Yield) indicates that interest rates will remain low (page 18-19). Please fully explain what Mr. Coyne understands by the unbiased expectations theorem of the term structure and what a steeper yield curve means.

Response:

Mr. Coyne believes the author is referencing his statements on pp. 18-19, where Mr. Coyne refers to both lower 30 year bond yields and increases in spreads of government bond yields since 2012, indicating that an "expectation that bond yields will remain low in the near term, but will move higher during later economic growth periods." This is reflected in the yield curve today and the projected upward shift in the level of interest rates in 2016 and 2017 from 2015's very low levels as shown below:



Source: RBC Economics - Research, Financial Market Forecasts, December 8, 2015

	Overnight	3-mo	2-yr	5-yr	10-yr	30-yr
2014 Actual	1.00	0.91	1.01	1.34	1.79	2.34
2015 Forecast	0.50	0.40	0.65	1.00	1.75	2.45
2016 Forecast	1.00	1.10	1.60	2.10	2.60	3.05
2017 Forecast	2.00	2.05	2.65	2.95	3.30	3.75

Source: RBC Economics - Research, Financial Market Forecasts, December 8, 2015

The "unbiased expectations theory" is one of several theories used to interpret the term structure of interest rates. Other theories include the "market segmentation theory" and "liquidity premium theory". According to the expectations hypothesis, you would earn the same amount of interest by investing and rolling over a series of one-year bonds as you would making a term investment of the same maturity. If the future interest rates are expected to rise, then the yield curve slopes upward, with longer term bonds paying higher yields. When interpreting the yield curve, it must be understood that it is not static; it shifts over time in response to macroeconomic conditions, the supply and demand for bonds of varying terms, money supply, and other factors. That is why it is common practice in Canada and the U.S. to consider forecasts of long-term bond yields, especially when these factors are in a state of flux, as they are in North America.

2.7 Please confirm that the State Street investor confidence index refers to the US and not the Canadian capital markets (page 21). If not confirmed, please fully explain why not.

Response:

Confirmed. Figure 5 on page 22 of Mr. Coyne's direct testimony also shows the North American Institutional Investor Confidence Index, which focuses exclusively on institutional investors domiciled in the U.S. and Canada. The movement on both indexes has been very similar.

2.8 In reference to the data on page 23:

2.8.1 Can Mr. Coyne provide the support for the 13.82% long term growth rate and explain what this is for? Would Mr. Coyne accept that 13.82% earnings growth exceeds any prospective growth in GDP and is unsustainable.

Response:

According to Bloomberg, the 13.82 percent long term growth rate for the S&P/TSX is the aggregation of the respective growth rates for each of the individual securities for the next full business cycle (estimated by Bloomberg to normally fall between 3 to 5 years) and is dependent on analyst growth estimates for each of the individual companies making up the index. The index level growth estimate of 13.82 percent represents a share weighted average of each constituent long term growth estimate aggregated to the index level. Mr. Coyne presents this figure, along with the others on page 23, to show a synopsis of the market outlook between 2012 and 2015. Mr. Coyne is not using this figure in his analysis otherwise.

2.8.2 Can Mr. Coyne confirm that in periods of zero or low inflation (1950's) the earnings yield was used as an estimate of the cost of equity capital, particularly in the US where tax regulations required that the bulk of earnings be paid out as dividends. If not confirmed, please fully explain why not.

Response:

Mr. Coyne is unable to confirm that in periods of zero or low inflation (1950's) that the earnings yield was used as an estimate of the cost of equity capital, nor did he consider such information relevant in the development of his cost of capital recommendation for FortisBC Energy Inc.

2.8.3 Consistent with 2.8.2 above, explain why a decline of 1.67% in the earnings yield would not be used as a proxy for the decline in the fair rate of return in a low inflation environment?

Response:

A change in the earnings yield of the market index would be a poor proxy for required utility returns. First, this is a broad market index, and does not relate to a Canadian regulated distribution utility. Second, a variety of market factors affect the earnings yield that may have no bearing on required utility returns. Required utility returns are impacted by utility earnings, equity appreciation, dividend policy, business risk and related factors not captured in a broad market index earnings yield. Mr. Coyne notes that the earnings yield for the S&P/TSX utilities index increased by 1.23 percent from June 2012 to August 2015 and has continued to increase another 0.69 percent from August 2015 to the date of this response, December 15, 2015. This illustrates that the broader market and utilities do not necessarily move in tandem, nor would this suggest a decline in required return

Third Topic: **Integration between the US and Canada**

Reference: **Exhibit B-1, Appendix B, Mr. Coyne's evidence page 24-28**

Preamble:

Mr. Coyne discusses the growing integration between the US and Canadian economies

Question 3:

3.1 Does Mr. Coyne accept that if two securities are combined in a portfolio that unless they are perfectly correlated the overall risk of the portfolio decreases? If not accepted please explain fully why not.

Response:

Not necessarily. For example, an investor from a developed country may decide to diversify its portfolio into an emerging international market. The new portfolio combined may be riskier, and the aggregate returns more volatile. The nature of the new investment matters.

3.2 Does Mr. Coyne accept that if investors are now able to buy US and Canadian (and global) securities that unless they are all perfectly correlated, the risk of a portfolio decreases? If not accepted please explain fully why not.

Response:

It is not clear from the question what portfolio is being addressed, and the nature of the risks of the securities, but as a general premise, Mr. Coyne agrees that diversification tends to reduce the risk of a portfolio. However, Mr. Coyne is not setting a return for a portfolio, but rather a single utility with its own set of risks.

3.3 Does Mr. Coyne accept that if risk decreases so too does the required and fair rate of return? If not accepted please explain fully why not.

Response:

There are two questions embedded in one. If risk is measurably reduced, the required return on that investment may be reduced, but only if other market circumstances remain constant.

Otherwise, return requirements may either increase or decrease. That is not equivalent, however to a "fair return", which is a regulatory standard. In order for a regulated rate of return to be judged fair, the company must be provided with a reasonable opportunity to earn a return that meets three requirements:

- Comparable investment standard;
- Financial integrity standard; and
- Capital attraction standard.

These standards must be met individually and in total in order to satisfy a fair return.

3.4 Please provide references to all areas of Mr. Coyne's evidence where he has taken into account the reduced risk and lower required returns consistent with increasing market integration between the US and Canada.

Response:

Mr. Coyne's DCF and CAPM analyses are based on market data, which accounts for any importance investors might place on the integrated nature of the Canadian, U.S. and global economies and capital markets.

3.5 If Mr. Coyne disagrees with anything in 3.1-3.4 please provide references to any research that shows that increasing integration of capital markets does not cause the fair return to decrease?

Response:

Please refer to Mr. Coyne's responses to AMPC-Concentric IRs 1.3.1 to 1.3.4.

3.6 Mr. Coyne points to the correlation between GDP growth rates between the US and Canada, unemployment rates, inflation etc., as indicators of integration between the two countries. Please provide a similar analysis for Canada and the UK, Japan and Europe.

Would Mr. Coyne accept evidence from those countries for the cost of capital if the metrics are approximately the same? If not accepted please explain fully why not.

Response:

Mr. Coyne focused on the comparability of U.S. utilities because they present a larger universe of publicly traded companies operating in a similar macroeconomic and business environment, with a comparable regulatory framework, common legal principles, and a physically connected network of gas and electric systems. There is also considerable cross-border investment in utilities and more broadly, as the countries are their respective largest trading partners. Lastly the data for U.S. utilities is readily available from a variety of public and subscription sources. For these reasons, Mr. Coyne did not find it necessary to consider utilities, regulatory frameworks, or macroeconomic assessments of other countries in this analysis. He has, however, previously provided assessments that included Canada, the U.S., U.K., Australia, and the Netherlands. In that report, based on its analysis for the OEB, Concentric concluded:

> CEA also extends the analysis beyond Canada and the U.S., to determine whether other countries, specifically the U.K., Australia, and the Netherlands, might form an adequate basis of comparison and thus allow for a larger population of comparable companies. While the gas markets in these countries bear certain resemblances to those of Canada and the U.S., there are a few substantial differences that weaken the comparison. Thus, allowed returns in these countries are not considered adequate benchmarks against which to examine ROEs in Ontario.
>
> As a result of the interplay between the Canadian and U.S. markets, Canadian utilities compete for capital essentially on the same basis as utilities in the U.S. In the current market environment, no fundamental differences were identified that would indicate a significant difference in investor required returns between the two markets. Capital flows efficiently between these two markets, and over the long-term, equity investors earn nearly identical returns. On the issue of subsidiaries competing for capital we find that subsidiaries of larger holding companies ultimately compete for capital much like stand alone companies, as they must compete among their affiliates for parental investment. Nonetheless, the parental obligation to invest necessary capital to maintain system integrity will typically provide the wholly owned subsidiary sufficient capital to sustain operations, where no such provision exists for standalone utilities. Over time, however, the equity returns must ultimately reward the parent or investor at the same rate as a similar investment of comparable risk. This "comparability standard" is a guiding principle in both Canadian and U.S. utility regulation. (A Comparative Analysis of Return on Equity of Natural Gas Utilities, Concentric Energy Advisors, Prepared for The Ontario Energy Board, June 14, 2007)

3.7 Mr. Coyne notes that yields on 10 year government bonds in the US and Canada have been similar. Please provide the underlying data for Figure 6 as well as similar data for 91 day treasury Bills and the long bond (30 year).

Response:

The long bond is pictured in Figure 6 and this data as well as the 3 month treasury bills are provided in Attachment 3.7.

3.8 Does Mr. Coyne accept that integration means the "law of one price" holds, that is, the same thing sells for the same price in both countries If not accepted please explain fully why not.

Response:

The "law of one price" is an economic and trade principle based on the assumption that prices for perfectly homogeneous goods will be priced equally between locations, absent any transportation, economic barriers, or market information gaps; otherwise arbitrage will reduce any price differentials. Mr. Coyne did not assume either perfect integration or perfectly homogeneous goods in development of his cost of capital recommendation for FortisBC Energy Inc. He did, however, demonstrate:

> On balance, the economic and business environments of Canada and the U.S. are highly integrated and exhibit strong correlation across a variety of metrics, including GDP growth and government bond yields. From a business risk perspective, including overall business environment and competitiveness, Canada and the U.S. are ranked closely when compared against other developed and developing countries. Based on these macroeconomic indicators, there are no fundamental dissimilarities between Canada and the U.S. (i.e., in terms of economic growth, inflation, unemployment, or government bond yields) that would cause a reasonable investor to have materially different return expectations for a group of comparably situated utilities in the two countries.[3]

[3] Coyne Direct p. 27-28

3.9 On Figure 6, in 2003, 10 year Canada bond yields exceeded those in the United States, whereas currently they are considerably less. Please fully explain whether this is due to the fact that the government bond market is not integrated, or alternatively that the US government is regarded as riskier than Canada?

Response:

Mr. Coyne explains on pages 9-10 of Concentric's report that the Canadian economy was in a technical recession during the first two quarters of 2015; consequently, the Bank of Canada reduced interest rates on two occasions in 2015 in order to provide monetary stimulus to support the Canadian economy. By contrast, economic growth has been relatively stronger in the U.S. in 2015, with the unemployment rate declining to 5.0 percent. Mr. Coyne does not view the higher government bond yields in the U.S. as a sign that the U.S. market is more risky than Canada; rather, he attributes it to the relative weakness of the Canadian economy, as lower oil prices and weaker exports continue to filter through the economy in Canada. An article earlier in the year in the Globe and Mail, citing research, focuses on these key relationships:

> *Bespoke noted that Canada's long-standing economic ties to the United States, which was the only one of the G7 or BRIC economies that had its growth outlook upgraded by the International Monetary Fund, may help the country stave off economic disaster.*
>
> *In fact, over the past 30 years, quarterly economic growth in Canada has been positive 95 per cent of the time if the U.S. economy expanded during that period.*
>
> *Canadians may also want to take solace in the fact that the bond market, an amalgamation of the beliefs of fallible humans, is not omniscient.*
>
> *"Diving yields like we're seeing do tend to suggest genuine concern about a more lasting slump; the market seems to be pricing in that lower oil prices and weak global growth may be more of a permanent shock," said CIBC World Markets chief economist Avery Shenfeld. "However, the bond market's record of forecasting has some hits and some misses, and in this case, it seems unduly pessimistic about the medium-term economic landscape."*[4]

On the issue of the integration of Canadian and U.S. bond markets, as Mr. Coyne noted in his evidence (*See* Coyne Direct Testimony at p. 27):

> *The correlation between average yields on 10-year government bonds in Canada and the U.S. since 1990 has been strong at 0.97, the highest of all macroeconomic indicators*

[4] http://www.theglobeandmail.com/report-on-business/economy/dropping-bond-yields-signal-poor-outlook-for-economy/article22713269

compared. Correlations of this degree are reflective of closely integrated financial markets.

These data indicate closely integrated bond markets.

3.10 Does Mr. Coyne attribute any relevance to the fact that currently long term US government bond yields are higher than in Canada and are forecast to remain so? If so please fully explain the relevance.

Response:

Mr. Coyne specifically accounts for the differences in long-term bond yield forecasts in Canada and the U.S. in his CAPM analysis (see Coyne Direct, p. 41).

3.11 Would Mr. Coyne accept that the yield on a long term Government of Canada bond is the only unbiased expectation for a long run rate of return available since there is no default risk? If not accepted please explain fully why not.

Response:

No. The long-term Government of Canada bond yield provides a very good indicator of the risk free rate today, but as discussed previously in response to the response to AMPC-Concentric IR 1.2.6, bond yields are dynamic and change over time, and today's bond yield may not be the best proxy for the risk free rate in the future. Mr. Coyne believes the forecasted risk-free bond yield, applicable to the period rates will be in effect, is the preferred indicator of the risk-free rate, particularly in the face of dynamic and abnormal market conditions.

Fourth Topic: Proxy samples

Reference: Exhibit B-1, Appendix B, Mr. Coyne's evidence page 28-39

Preamble:

Mr. Coyne discusses his three proxy samples

Question 4:

4.1 Mr. Coyne bases the validity of using a proxy group on his judgement that their business operations are similar. Would Mr. Coyne agree that unless they are the *same*, not similar, estimates have to be adjusted? If not agreed to, please explain fully why not.

<u>Response:</u>

No. As discussed on pages 31-34 of his direct testimony, Mr. Coyne believes that it is important to select a proxy group of companies that possess similar business and financial characteristics for the cost of equity analysis. If the proxy group companies are chosen based on reasonable screening criteria, such as those used in Mr. Coyne's analysis, then the resulting proxy group will be risk comparable to the company for which the cost of equity is being estimated (in this case, FortisBC Energy Inc.). Under those circumstances, Mr. Coyne believes it would be unusual for the slight differences in risk across the proxy companies to rise to the level of significance to warrant an adjustment to the ROE estimate to account for differences in risk between the proxy group companies and FortisBC Energy Inc.

4.2 Please provide direct quotes and evidentiary support from all Canadian regulatory decisions that demonstrate they have used estimates from US proxy samples *without* adjustment?

<u>Response:</u>

As Mr. Coyne states in his testimony on p. 15:

> *Canadian regulators have accepted the use of U.S. data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. The development of a proxy group comprised entirely of Canadian electric utilities is compromised by the small number of publicly traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of revenues and net income from operations other than regulated electric utility service. This problem has been exacerbated by the continuing*

> *trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility companies.*

In its 2013 Generic Cost of Capital Decision, the British Columbia Utilities Commission accepted the use of U.S. data and made no explicit adjustment.[5]

In its 2009 Generic Cost of Capital Decision, the Ontario Energy Board ("OEB") also accepted the use of U.S. data without making any adjustments. On pages 21-23 of the decision, the OEB stated[6]:

> *Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money."[15] 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. The analyses of Concentric Energy Advisors and Kathy McShane of Foster Associates Inc. are particularly relevant in this regard, and substantially advance the issue of establishing comparability to meet the requirements of the FRS.*
>
> *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.*
>
> *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.*
>
> *The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking.*
>
> *Finally, the Board agrees with Enbridge that, while it is possible to conduct DCF and CAPM analyses on publicly-traded Canadian utility holding companies of comparable risk, there are relatively few of these companies. As a result, the Board concludes that*

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[5] BCUC, GCOC Stage 1, Decision dated May 10, 2013.
[6] OEB, GCOC, EB-2009-0084, Decision dated December 11, 2009.

> *North American gas and electric utilities provide a relevant and objective source of data for comparison.*

In its TQM Decision, the National Energy Board ("NEB") found that U.S. market returns are relevant to the cost of capital for Canadian firms, and that the regulatory regimes in Canada and the U.S. are sufficiently similar as to justify comparison. Moreover, the NEB found that Canadian utilities are competing for capital in global financial markets that are increasingly integrated. The NEB recognized that it is no longer possible to view Canada as insulated from the remainder of the investing world, and that doing so would be detrimental to the ability of Canadian utilities to compete for capital.[7] These findings suggest that it is reasonable and appropriate to consider a proxy group of U.S. utility companies as sufficiently comparable to Canadian regulated utilities in terms of their risk profile. Specifically, the NEB stated:

> *The Board is not persuaded that the U.S. regulatory system exposes utilities to notable risks of major losses due either to unusual events or cost disallowances. The Board views the losses and disallowances experienced by U.S. regulated entities as a result of the restructuring that took place to terminate the merchant gas function of pipelines, as well as some other circumstances such as the Duquesne nuclear build, to be, to a large extent, unique events. The Board also finds that such instances are not likely to weigh significantly in investors' perceptions today, and would thus have little or no impact on cost of capital.*[8]

Mr. Coyne confirms that in the 2009 BCUC decision for Terasen Gas (now FortisBC Energy), the Commission Panel did make an adjustment to the DCF estimate for the U.S. proxy group of 50 to 100 basis points.

Since that decision was issued in 2009, Moody's issued a report in September 2013 discussing its evolving view of U.S. utility regulation. Please refer to the attached report for quotes regarding Moody's more favorable view of the relative credit supportiveness of the U.S. utility regulatory environment. After the Moody's report was published in 2013, it became clear that rating agencies and investors had come to the conclusion that utility regulation in Canada and the U.S. was comparable, a view which Concentric had held for several years prior to the Moody's report. For that reason, Mr. Coyne does not believe that a risk adjustment to the U.S. results is necessary or warranted in this proceeding.

Please refer to Attachment 4.2.

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7 National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at p. 66-72.
8 Ibid.

4.3 Would Mr. Coyne accept that the BCUC in 2009 downwardly adjusted estimates drawn from US proxy samples by 0.50% -1.0%? If so can he explain where in his testimony he has downwardly adjusted his estimates? If not accepted can he provide any recent data that indicates the BCUC's 2009 decision was incorrect?

Response:

Please refer to Mr. Coyne's response to AMPC-Concentric IR 1.4.2.

4.4 Would Mr. Coyne accept that in a 2009 Gaz Metro decision (page 295) the Régie stated:

> "The evidence therefore does not make it possible to conclude that the regulatory, institutional, economic and financial contexts of the two countries and their impacts on the resulting opportunities for investors are comparable."

If not accepted please explain fully why not.

Response:

No, Mr. Coyne does not accept that the cited quote represents the Regie's ultimate position with respect to the usefulness of U.S. data to an ROE analysis. Below the Régie indicated in the same 2009 Gaz Metro Decision that it weighted Canadian and U.S. data equally:

> [249] With respect to the weighting of Canadian and U.S. data to be used in estimating the market risk premium, the Régie, in decision D-99-150, established a weight of 60% for Canadian data and 40% for U.S. data. Based on the evidence of this case, the Régie bases its estimate of the market risk premium using equal portions of Canadian and U.S. data. It considers that the opening of markets offers investors various investment options that it is necessary to reflect the situation in establishing a reasonable rate of return. It also justifies greater consideration of U.S. data because of the increasing integration of the two economies.[9]

[9] English translation of Régie de L'Énergie, Decision 2009-156 (R-3690-2009), Gaz Metro, December 7, 2009, at paragraph [249].

4.5 Would Mr. Coyne accept that the PUB of Newfoundland and Labrador similarly reduced US DCF estimates from the company witness at that time, Ms. McShane, by 0.50-1.0% since they did not regard them as the same. If not accepted please explain fully why not.

Response:

Mr. Coyne confirms that the PUB of Newfoundland and Labrador did make an adjustment to the US DCF results by 0.50-1.0% in the Newfoundland and Labrador Board of Commissioners of Public Utilities, Order No. P.U. 13(2013), on page 31. This is not, however, descriptive of the broader Canadian landscape on this matter. Please refer to the response to AMPC-Concentric IR 1.4.2.

4.6 In terms of Mr. Coyne's US regulated sample, do any of these companies have subsidiaries with deemed common equity ratios? If so please provide full details.

Response:

The deemed or otherwise authorized equity ratios of the U.S. proxy group subsidiary companies can be found in Table 20 on p. 101 of Mr. Coyne's testimony.

4.7 In terms of the Brattle group report referenced on page 33:

4.7.1 Would Mr. Coyne agree that the Brattle group normally intervene on behalf of companies. If not, please indicate any times they have appeared in Canada on behalf of other participants in a hearing.

Response:

The particular report referenced in the IR was prepared by the Brattle Group for the British Columbia Utilities Commission, as the result of an RFP. Mr. Coyne assumes the Commission selected its consultant based on their qualifications and is not aware of the Brattle Group's specific mix of engagements.

4.7.2 Would Mr. Coyne agree that the statistical tests that the Brattle group refer to on page 36 use the 30 day Treasury Bill yield as the risk free rate, whereas for utilities experts generally use the long Canada bond yield which is higher by the term spread? To the extent that the term spread averages 1.25% it would give the result they refer to. If not, please fully explain why not.

Response:

Concentric, on page 36 of its report, cites to page 52 of the Brattle Report. There is no mention of the topic addressed in the question 4.7.2, nor any mention on page 36 of the Brattle Report.

4.7.3 Please confirm that Fernandez' paper (footnote 51) is a working paper and has not passed peer review. If not confirmed please explain fully why not.

Response:

Dr. Fernandez' paper is published research in his role as Professor of Financial Management and Chair of PricewaterhouseCoopers, Chair of Corporate Finance at the IESE Business School, University of Navarra, Madrid, Spain. His background is:

- Ph.D. in Business Economics (Finance), Harvard University
- Master of Arts in Business Economics, Harvard University
- Master in Business Administration, IESE, University of Navarra
- Bachelor´s degree in Industrial Engineering, University of Navarra.

Mr. Coyne is unaware of whether Dr. Fernandez has submitted this research paper for review in a peer-reviewed journal.

4.7.4 Is Mr. Coyne aware that the Alberta Utilities Commission was presented with the Fernandez paper and stated (AUC 2011 Decision paragraph 63)

> 63. The Utilities also noted that Dr. Fernandez (whose work had been cited by Dr. Booth) had provided evidence that the CAPM does not work and had concluded that historical betas are useless to estimate the expected return of companies.[58] However, the Commission continues to hold the view that CAPM is a theoretically sound and useful tool, among others, for estimating ROE.

Does Mr. Coyne disagree with the AUC's conclusion? If Mr. Coyne disagrees, please fully explain.

Response:

Mr. Coyne finds the CAPM is a useful tool, among others, for estimating the cost of equity. He has used the CAPM model in his analysis and given it equal weight with the DCF. However, Mr. Coyne also recognizes the shortcomings of the CAPM, as illuminated in Mr. Fernandez's paper and several others criticizing the ability of the CAPM to reasonably predict expected equity returns. The CAPM is based on highly theoretical assumptions on portfolio diversification, its betas and risk free rates are highly sensitive to market disruptions, and beta in its raw form can not accurately predict the returns of low-risk stocks without adjustment. Though the CAPM inputs may require modification by the expert such that they will produce reasonable estimates of equity returns, they should not be used in isolation, but should be one tool of several for estimating the required returns for utility equity.

4.8 Is Mr. Coyne aware that a FEI witness in the 2012 hearing (Ms. McShane) agreed that typically US utilities were riskier than Canadian ones and answered a question put to her in an AUC hearing as follows (CAPP-IR-ROE9a):

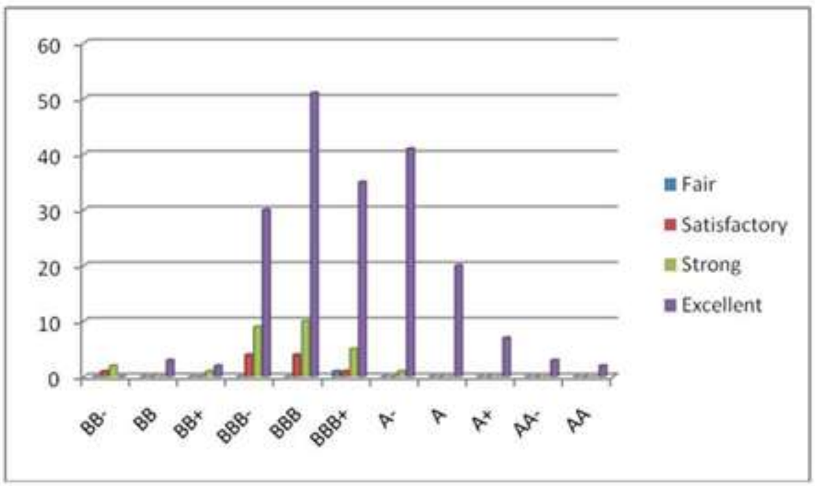
> Ms McShane "agrees that the universe of US utilities has higher business risk than the typical Canadian utility, which is a wires and pipes utility, whereas the preponderance of US utilities are integrated electric utilities, which are of inherently higher business risk than distribution utilities."

If Mr. Coyne disagrees with this assessment please fully explain why.

Response:

Mr. Coyne's view on the relative risk of FortisBC Energy and the companies in his U.S. proxy group are provided on pages 79-81 of his direct testimony. In particular, Table 15 on page 81 provides an overview of Mr. Coyne's risk comparison. See also the Business Risk Appendix, which provides a detailed risk assessment for the companies in Mr. Coyne's Canadian and U.S. proxy groups. Mr. Coyne would agree that vertically integrated electric utilities are generally riskier than wires and pipes utilities, but since the utilities included in his U.S. proxy group are gas distribution utilities, Mr. Coyne does not find Ms. McShane's quote relevant in this proceeding.

4.9 In answer to an information request in a 2010 Line 9 hearing before the National Energy Board (IOL information request #197d) Ms. McShane provided the following histogram of the number of US utilities in each bond rating and their respective business risk scores. Please update this histogram and in any event comment on whether it remains accurate for US utilities?



Response:

Mr. Coyne does not know which utilities are included in Ms. McShane's histogram, e.g. gas, electric, transmission, and therefore cannot update. However, Mr. Coyne has conducted a review of the ratings distribution of U.S. electric utilities. That analysis is provided in Attachment 4.9. The Attachment shows that the S&P credit ratings have moved somewhat higher for U.S. regulated electric utilities since 2010. Note there are fewer BBB- rated companies at the lower end of investment grade. Based on Moody's September 2013 report, regulatory risk for U.S. utilities is seen as more favorable and credit supportive than was previously thought by Moody's. In light of that Moody's report, business risk scores should generally be somewhat better than in 2010 due to lower regulatory risk in the U.S. Mr. Coyne notes that his chart includes only investor-owned utilities; he is unsure of the coverage in Ms. McShane's chart, which may include government-owned entities, normally ranked A or better. Bonneville Power's current rating is AA+, and TVA's rating is AAA, for example. Adding the government-owned U.S. utility entities would move the aggregate ratings profile upwards.

Please refer to Attachment 4.9.

Fifth Topic: **ROE Estimates**

Reference: **Exhibit B-1, Appendix B, Mr. Coyne's evidence page 39-61**

Preamble:

Mr. Coyne discusses risk premium and DCF models on pages 39- 61

Question 5

5.2. Mr. Coyne uses a medium forecast of the ten year government bond rate from 2016-2018 on the basis that investors "factor higher interest rate levels in their forward looking return expectations." (page 41)

5.2.1. Please fully explain why Mr. Coyne judges the market to be inefficient, in the sense that investors already buy long term bonds with an expectation of the future path of interest rates.

Response:

Mr. Coyne's use of a medium term forecast of ten year government bond yield, to which he adds the average historical spread between ten and 30-year government bonds yields does not imply Mr. Coyne believes the market is inefficient. Investors, and specifically utility investors, take a long term view of their returns, and a forecast of the risk free rate helps captures these expectations. As stated in the response to AMPC-Concentric 1.5.3, in the 2013 Generic Cost of Capital proceeding, the BCUC stated that it considered that the appropriate opportunity cost is better measured by the forecasted yield on the long-term risk free instrument. Please also refer to Mr. Coyne's responses to AMPC-Concentric IR 1.2.6 and CEC IR 1.3.1.

5.2.2. Can Mr. Coyne fully explain why he is not double counting the expected increase in interest rates?

Response:

Use of the forecast bond yield to determine the risk free rate has not resulted in double-counting the expected increase in interest rates. It merely reflects expectations for the evolution of future long term bond yields.

5.2.3. Does Mr. Coyne disagree with financial theory that the best predictor of the long term return risk free yield is the current long term bond yield as the yield on the government of Canada bond is default free? If he disagrees, please explain fully why.

Response:

Yes. Mr. Coyne finds the forecast long term bond yield is better suited for calculating a forward-looking ROE estimate than current bond yields. Mr. Coyne believes that consensus forecasts for bond yields, as he has used, convey important information to investors regarding expectations for future interest rates over their relevant investment horizon. The use of a forecast is especially appropriate when it's clear that the consensus is that long term rates will deviate from their current historic lows. Please also refer to the responses to AMPC-Concentric IRs 1.2.6, 1.3.11 and 1.5.2.1.

5.3. Please provide all evidence that Mr. Coyne is aware of that indicates economists are better predictors of future interest rates than participants in the bond market who put money behind their forecasts.

Response:

Please refer to the response to AMPC-Concentric IR 1.5.2.3. Mr. Coyne believes that consensus forecasts for bond yields, as he has used, convey important information to investors regarding expectations for future interest rates over their relevant investment horizon. The use of a forecast is especially appropriate when it's clear that the consensus is that long term rates will deviate from their current historic lows. Mr. Coyne has not studied the comparative performance of economists vs. bond markets, but he is aware that the BCUC in the most recent GCOC proceeding considered this matter, and noted:

> *Evidence submitted to the Panel indicates that, at the time of filing, returns available to Canadian investors on long-term Government of Canada default free bonds were in the 2.6 to 3 percent range. (Exhibit B1-9-6, Appendix F, p. 77; Exhibit C6-12, pp. 53-71) Although this return was available to investors and therefore seems to meet the requirement of an opportunity cost, <u>all of the experts submit that the appropriate opportunity cost is better measured by the forecasted yield on a long-term risk free</u>*

> *instrument and that in some cases even this estimate should be adjusted.* [Emphasis added][10]

The panel ultimately determined a forecast bond yield was appropriate.

Furthermore, the Consensus Economics forecast is based on a survey of banks, academics, professional forecasting and economic research firms. These respondents not only have access to current bond yields, but are active participants in the trading of these securities or are uniquely positioned with regards to the interplay of financial markets and the economy. Below is the list of institutions whose members participated in the April 13, 2015 survey for Canada:[11]

- Informetrica
- Royal Bank of Canada
- Oxford Economics
- Citigroup
- Conference Board of Canada
- Desjardins
- Econ Intelligence Unit
- Economap
- National Bank of Canada
- University of Toronto
- BMO Capital Markets
- IHS Economics
- Scotia Economics
- Bank of America – Merrill
- JP Morgan
- CIBC World Markets
- Capital Economics

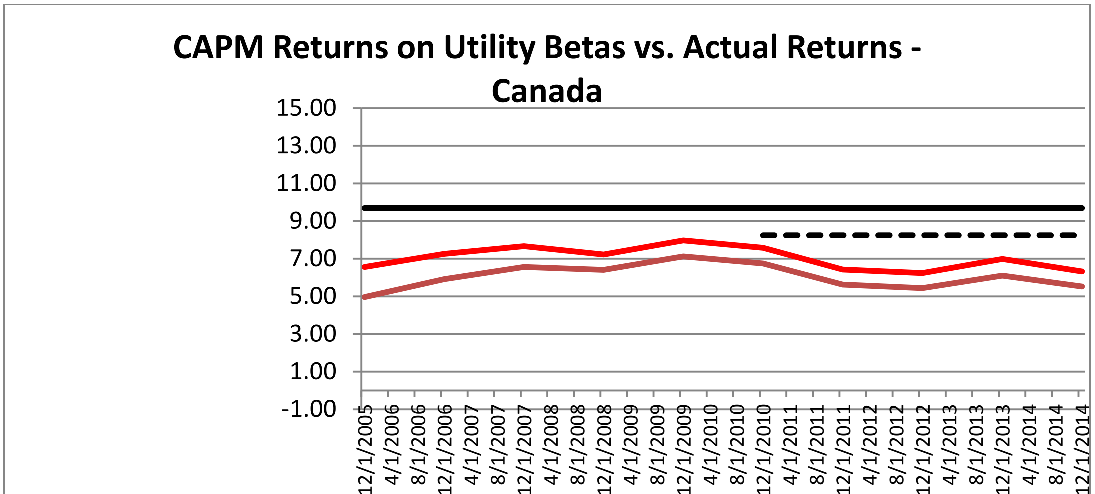
[10] Op. cit., p. 59.
[11] Consensus Forecasts, Consensus Economics, Inc., Survey Date April 13, 2015 at 16.

5.4. Mr. Coyne confirms that both Value Line and Bloomberg adjust their betas (page 70). Please provide any evidence that Mr. Coyne is aware of that those utility betas revert to 1.0 as assumed in the Value Line and Bloomberg adjustment methodology.

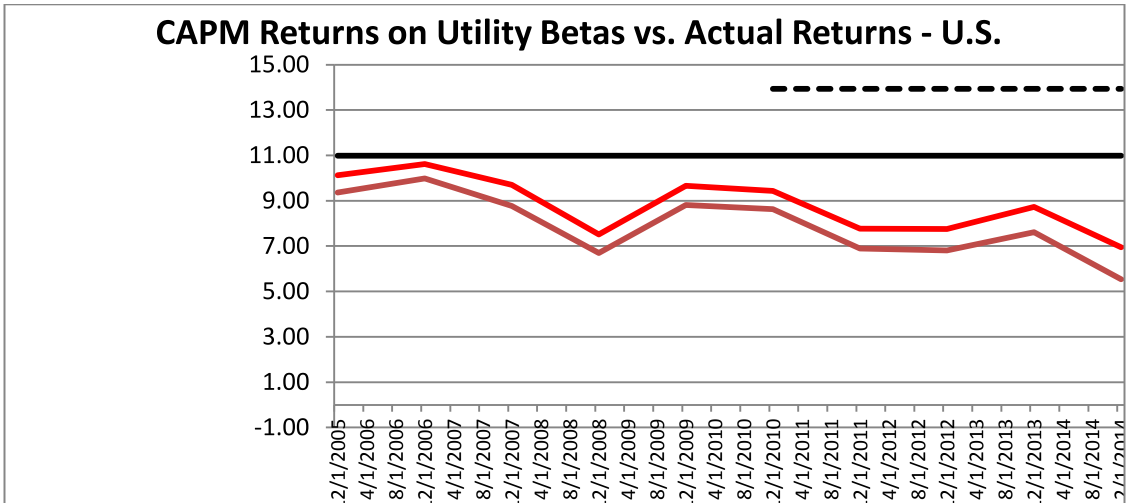
Response:

As Mr. Coyne has stated on pp. 42-43 of his evidence, there are two primary reasons to adjust beta. First, empirical studies provide evidence that beta has a tendency to move towards the market mean of 1.0 over time. That is not to say that they actually become 1.0 or even become the adjusted beta value. The second and potentially the most important reason to adjust beta towards 1.0 is that the error terms on low betas (e.g. below the market mean of 1) tend to underestimate future returns. Conversely, high betas tend to overestimate returns. To determine whether it is appropriate to adjust beta towards 1.0, one should not focus on the betas themselves but the estimated equity returns that are produced from the use of those betas and which better approximates the actual investor returns.

As shown in Mr. Coyne's exhibit JMC-2, the Canadian S&P/TSX Utilities Index market returns have earned 9.69 percent over the last 10 years and 8.25 percent over the last 5 years, well above that which would have been produced by a standard CAPM analysis using prevailing 30-year bond yields, the Duff & Phelps historic market risk premium, and either raw or adjusted betas. The same holds true for the U.S. S&P 500 Utilities Index. Mr. Coyne's analysis is presented below. From this analysis, it is apparent that unadjusted betas do a poor job of projecting the returns they are designed to estimate. Though Mr. Coyne would not rely on the utility index to set returns for an individual utility, the analysis does show that even when applying betas adjusted towards the market mean of 1, modifications must be made to the CAPM to reasonably project utility equity returns.



	12/30/2005	12/29/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/30/2011	12/31/2012	12/31/2013	12/31/2014
Adjusted Betas Canada	6.33	6.98	6.25	6.42	7.58	7.97	7.23	7.67	7.26	6.55
Raw betas	5.52	6.11	5.44	5.63	6.75	7.12	6.41	6.55	5.92	4.96
10-yr Actual Returns	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69
5-yr Actual Returns	8.25	8.25	8.25	8.25	8.25					



	12/30/2005	12/29/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/30/2011	12/31/2012	12/31/2013	12/31/2014
Adjusted Betas U.S.	6.95	8.73	7.75	7.76	9.43	9.65	7.52	9.70	10.63	10.12
Raw betas	5.55	7.61	6.80	6.90	8.63	8.81	6.69	8.78	9.98	9.36
10-yr Actual Returns	10.98	10.98	10.98	10.98	10.98	10.98	10.98	10.98	10.98	10.98
5-yr Actual Returns	13.93	13.93	13.93	13.93	13.93					

Please refer to p. 43 of Mr. Coyne's testimony for a discussion of academic studies that conclude that beta reverts towards the market mean of 1, and that beta tends to underestimate returns of low-beta companies.

Another form of the CAPM analysis, which is sometimes referred to as the "Empirical CAPM,"[12] can be used in estimating the cost of equity. The Empirical CAPM calculates the product of the adjusted Beta coefficient and the market risk premium and applies a weight of 75% to that result. The model then applies a 25% weight to the market risk premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the Zero-Beta CAPM result, as noted in the equation below:

$$ke = rf + 0.75\beta(rm - rf) + 0.25(rm - rf)$$

where:

ke = the required market ROE

β = Adjusted Beta coefficient of an individual security

rf = the risk-free rate of return

rm = the required return on the market as a whole.

The Empirical CAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low Beta coefficients, such as regulated utilities. The advantage of the Empirical CAPM is that it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the "traditional" CAPM underestimates the "alpha," or the constant return term.[13]

5.5. Please indicate whether Value Line is freely available or only available through subscription and how much it costs.

Response:

Value Line is a subscription-based investment publication that is widely distributed and available at public libraries. The cost of Concentric Energy's Value Line subscription is confidential.

[12] *See e.g.,* Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 189.
[13] *Ibid*., at 191.

5.6. Please explain why Mr. Coyne has not used other publicly reported betas, for example, Yahoo or the Financial Post, that do not adjust their beta estimates?

Response:

Please see pages 42-44 of his direct testimony for the reasons why Mr. Coyne has used adjusted beta coefficients.

5.7. Please provide citations from any Canadian regulator that has accepted the beta adjustment methodology used by both Value Line and Bloomberg.

Response:

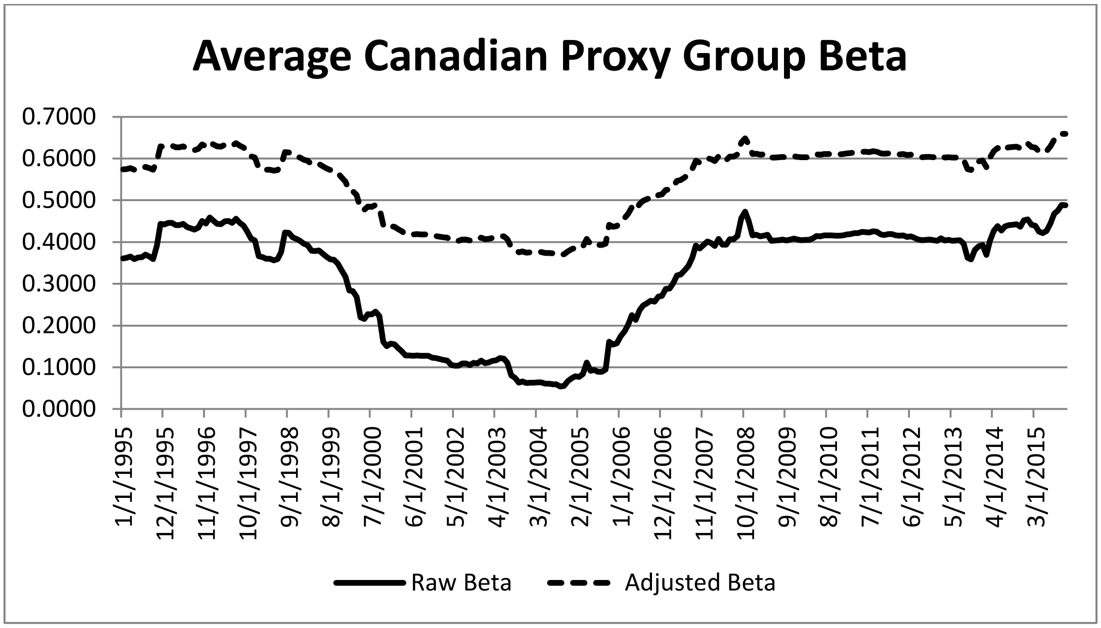
Mr. Coyne is aware, from his experience, that Canadian regulators have considered the issue of beta adjustments in a broad number of cases where CAPM evidence has been presented. Commissions do not always articulate their judgments regarding the specific adjustments they have accepted, and Mr. Coyne has not researched Canadian decisions for such citations. Mr. Coyne is not aware of any commission that has relied upon "raw" betas. In his experience, the Value Line and Bloomberg methodologies are widely accepted and utilized by financial analysts, investors, corporations, and broadly accepted by U.S. regulatory commissions. The Brattle Group summarizes this widely adopted methodology in its report for the BCUC:

> Beta estimates are provided by many data services for Canadian, American and other traded companies. The most common methodology to estimate betas is to use the most recent five years of weekly or monthly return data. These betas may then be adjusted towards one as adjustment for sampling reversion that was first identified by Professor Marshal Blume (1971, 1975). (The Brattle Group, Survey of Cost of Capital Practices in Canada, Prepared for the British Columbia utilities Commission, May 31, 2012, pp 15-16)

5.8. Please indicate the last time that the average beta for Mr. Coyne's sample of Canadian utilities was 0.65 as indicated on page 44.

Response:

Below Mr. Coyne has developed an analysis of the average raw and adjusted betas for the Canadian proxy group from Bloomberg from 1995 to present. As the data shows, the Canadian proxy group betas are currently at their highest point in the last 20 years. The Canadian proxy group betas in periods from 1996-1998 and during the global financial crisis in 2008 also approached this level.



Source: Bloomberg. Average of five years of weekly betas for S&P/TSX Utilities index for the Canadian companies.

5.9. Please provide the detailed calculation that Mr. Coyne used to arrive at an average beta of 0.57 on page 44 and fully explain why actual betas would not revert to this value rather than 1.0.

Response:

Please see notes to exhibit JMC-5, Schedule 2 for the detailed calculation that Mr. Coyne used to arrive at an average beta of 0.57. Please also refer to the Mr. Coyne's response to AMPC-Concentric IR 1.5.4.

5.10. Please provide the underlying data used in the Duff and Phelps and Morningstar publications referenced on page 45. Please indicate the fixed income instrument used for the risk free rate in these studies.

Response:

Please refer to Attachment 5.10 for the underlying data.

Duff and Phelps calculates the historical market risk premium using the income only return on government bonds. Since Duff and Phelps acquired its historical data from Morningstar, Mr. Coyne assumes that Duff and Phelps is also using the 20-year government bond as the risk free rate.

5.11. In footnote 57 Mr. Coyne references Dimson et al as the source for much of the Canadian return data. Can Mr. Coyne confirm that they are the authors of the Credit Suisse Global investment returns yearbook? Please fully explain why he did not use their estimates of the market risk premium.

Response:

Mr. Coyne assumes the reference is to footnote 75. Mr. Coyne is not aware of Dimson et al's relationship with Credit Suisse, nor did he have access to the Global Investment returns yearbook.

5.12. In terms of Mr. Coyne's forward looking DCF estimates for the market on page 48 please confirm that these are based on analyst forecasts and provide the source of the analyst forecasts. If not confirmed, please explain fully why not.

Response:

Confirmed. As stated on page 47 of Mr. Coyne's direct testimony, the forward-looking market risk premium is calculated by subtracting the risk-free rate for each country from the estimated total return for the overall market, as calculated using the DCF methodology for the S&P/TSX Composite Index in Canada and the S&P 500 Index in the U.S. The total market returns are based on forecasted analyst earnings per share growth rates for each company in the TSX Composite Index and the S&P 500 index for which growth rates are available. As indicated on Exhibits JMC-4, Schedules 1 and 2, the source of the growth rate forecasts is Bloomberg Finance LP.

5.13. Please explain why the BCUC should accept DCF estimates based on constant growth forecasts when Canadian regulatory tribunals have already indicated that such forecasts are best used in a multi-stage DCF model. Please provide Mr. Coyne's estimate of the DCF market return for both the US and Canada where these forecasts are used in a multi-stage DCF model.

Response:

The purpose of this forward looking MRP analysis was to derive the market's expectations of overall stock market returns based on observed stock prices, dividend yields and analyst growth rates. A multi-stage analysis would require introducing assumptions concerning second and third stage growth rates, and was beyond the scope of this analysis. Mr. Coyne introduces multi-stage analysis directly in his DCF models for his U.S. and Canadian proxy groups on Exhibit JMC-7, Schedule 2 to his Direct Testimony. The multi-stage results range from 8.9% to 9.8%, with an average of 9.4%, and are factored into Mr. Coyne's recommended ROE of 9.5%.

5.14. Please provide a copy of the Dimson et al paper referred to on page 48 and indicate whether it has been published.

Response:

The paper can be found in Attachment 5.14. The article was first published in the Journal of Applied Corporate Finance, Volume 15, Issue 4, pages 27–38, Fall 2003.

5.15. Please provide the underlying data for the market risk premium study referred to on page 49.

Response:

The data Mr. Coyne used for the referenced market risk premium study is provided in Exhibit JMC-6 to Mr. Coyne's Direct Testimony.

5.16. With the full regression model estimates in JMC-6, please confirm that the coefficient on the bond yield is not significant at normal levels and discuss why any weight should be placed on results that are not significant? If not confirmed, please explain fully why not.

Response:

Mr. Coyne indicated on page 49 of Concentric's report that "My analysis yielded a statistically significant value at the 85 percent confidence level, and in my opinion is informative of the relationship between bond yields and market risk premiums." Mr. Coyne finds that variables that contribute to the quality of the regression results, (i.e., has explanatory power and contributes to understanding the relationship between the risk free interest rate and the market risk premium) are informative.

Mr. Coyne takes exception to the statement that the "results are not significant." The independent variables are significant as further measured by the f test and provide insight into the dynamic relationship between bond yields and the market risk premium that he uses as a reasonableness check on his forward looking market risk premium.

5.17. Further to the discussion of the model in JMC-6, is it correct that inserting a dummy of 1.0 for the financial crisis resulted in a drop in the market risk premium of 45.18% and that this is highly significant? If not correct, please explain fully why not.

Response:

Yes. The addition of the dummy variable to capture and isolate the effects of the 2008 market collapse is significant with 99% confidence. Please also refer to Mr. Coyne's response to AMPC-Concentric IR 1.5.16 above.

5.18. Please insert into the estimation equation the actual values used for 2008 and 2009 during the financial crisis when the dummy variable is set equal to 1.0 and the forecast market risk premium. Explain why the BCUC should place any weight on a model that predicts that the market risk premium and the fair rate of return falls during a financial crisis?

Response:

The regression dummy variable simply removes the effect of the extraordinary decline in the TSX of -33% and in the S&P 500 of -37% in that year (see Exhibit JMC-2). This allows the regression to focus on all the other observations in order to capture the risk premium/bond yield relationship under more normal market conditions. He does not believe that the market risk premium declines in a financial crisis.

5.19. Please provide the Value Line book value per share and dividend per share forecast growth rates for each company and compare them with the earnings growth rates (footnote 79).

Response:

Please refer to Attachment 5.19.

As shown in the attachment, the average Value Line earnings per share growth rate for the companies in the U.S. proxy group is 5.50 percent, while the average Value Line dividend per share growth rate is 4.50 percent. For the Canadian proxy group, the only companies covered by Value Line are Enbridge and Fortis.

5.20. Please provide copies of the papers referenced in footnotes 90, 91 and 93.

Response:

The requested papers are provided in Attachment 5.20.

5.21. Mr. Coyne claims that analyst growth rates are no long biased high due to the optimism bias. For each of the firms in his US and Canadian samples please provide a table showing the dividend, earnings and book value per share for each year since 1990. From that data please compare the average and compound growth rates with the growth rate in Canadian and US GDP as appropriate. Is it Mr. Coyne's judgement that these forms on average have grown faster or slower than their respective economy's GDP growth rate?

Response:

Please refer to Attachment 5.21. The requested analysis is found in Attachment 5.21a.

Generally, the data show that earnings, dividends, and book value growth rates have grown faster than their respective economy's GDP growth rate.

For a white paper on this topic that further discusses the relationship, or lack thereof, between equity growth and GDP growth, please refer to Attachment 5.21b.

5.22. Is Mr. Coyne aware of the following statement from the 2011 AUC Generic Cost of Capital decision (paragraph 86) on analyst growth estimates:

> 86. In 2009, the Commission expressed concern about the potential upward bias in analysts' growth estimates.[75] However, Ms. McShane argued that, as long as investors believe the optimistic forecast, they would price the securities lower (resulting in a lower dividend yield) and the DCF test would still be an unbiased estimate of investor required returns. She indicated that this proposition had been successfully tested and described three tests, including the fact that such growth estimates have averaged less than GDP growth.[76] In the Commission's view, this line of reasoning does not resolve the issue because there is no evidence that investors believe optimistic forecasts. Therefore, the Commission remains concerned with the potential upward bias in analysts' growth estimates.

Response:

Yes. Mr. Coyne is aware of the AUC's statement from the 2011 AUC Generic Cost of Capital decision. On pages 55-56 of his direct testimony, Mr. Coyne discusses why he believes that financial regulations that were implemented in both Canada and the U.S. in 2001 and 2002 have resulted in fair disclosure and have reduced or eliminated the possibility of analyst bias. As support for this view, Mr. Coyne cites the 2010 article from the Financial Analysts Journal, which found that analyst bias had declined significantly or disappeared entirely in the U.S. since the Global Settlement.

Mr. Coyne notes that the ROE estimates in Table 1, on page 5 of his direct testimony demonstrate that the Constant Growth DCF results are generally consistent with the results of other models that he has used to estimate the cost of equity for FortisBC Energy Inc. Mr. Coyne has also presented the results of a Multi-Stage DCF model, which tempers the assumption of constant growth in perpetuity with a three-stage approach based on near-term, transitional and long-term growth rates. Mr. Coyne explains on pages 34 of his direct testimony that no financial model can exactly pinpoint the correct return on equity, and that quantitative models produce a range of results from which the market required ROE is determined.

5.23. Please provide all evidence Mr. Coyne has that would indicate that investors believe the optimistic estimates from analysts that addresses the concerns of the AUC expressed in the quote above.

Response:

Please refer to the response to AMPC-Concentric IR 1.5.22.

5.24. Please provide any data or reports that Mr. Coyne is aware of that support the assumption that his sample of US utilities have ever grown their dividends in line with US GDP growth.

Response:

Please refer to Attachment 5.21 provided in response to AMPC-Concentric IR 1.5.21, for Value Line data for each company in Mr. Coyne's U.S. and Canadian proxy groups for each year from 2005 through 2014.

As shown in the Attachment, the earnings, dividends and book value per share for the companies in the U.S. proxy group have grown at rates equal to or greater than U.S. nominal GDP growth over this period. The same is true for earnings, dividends and book value per share for Enbridge Inc. (the only company in my Canadian proxy group covered by Value Line) as compared to Canadian nominal GDP growth over this period.

Sixth Topic: Business Risk of FEI

Reference: Exhibit B-1, Appendix B, Mr. Coyne's evidence page 62-99

Preamble:

Mr. Coyne discusses FEI's business risk

Question 6:

6.1 Mr. Coyne's discussion of FEI's business risk mirrors that of the company.

a) Please indicate the timing of the meetings that took place between Concentric and FEI staff (both face and by conference call).

Response:

Mr. Coyne began developing his risk evidence for FEI in December 2014. At that time, Mr. Coyne reviewed FEI's prior GCOC application from the BCUC website as a basis for his understanding of the Company's prior risk assessment (which included a detailed business risk assessment submitted into evidence by FEI). Mr. Coyne understood that the same general framework for evidence would be developed in the present application and that it was the Company's view that its business profile and risks were fundamentally similar to those addressed in that Application and Decision. FEI was developing its own risk evidence for the current application in a parallel effort. To supplement Mr. Coyne's risk assessment, he gathered public financial information such as ratings analyst reports, consolidated financial statements, annual information forms, MD&A, investor presentations and news articles pertaining to Fortis Inc. and FortisBC Energy Inc.

During the course of Concentric's review of FEI's business risk, it held a series of calls to better understand and clarify FEI's risk. There were no face to face meetings. According to Concentric's records, there were four conference calls specifically to discuss business risk held on February 26, 2015, June 18, 2015, July 28, 2015, and September 3, 2015. There were also a handful of adhoc calls to assist Concentric with specific questions pertaining to FEI's business risk. FEI also provided a working draft of its business risk evidence on April 22, 2015 and a near final draft on September 15, 2015. In addition to the above, FEI provided credit rating reports on December 12, 2014 and on August 26, 2015; and a summary of their PBR plan on August 19, 2015.

b) Please provide copies of all materials that FEI passed to Mr. Coyne to brief him on FEI's business risk.

Response:

Please refer to Mr. Coyne's response to AMPC-Concentric IR 1.6.1.a above. The documents provided are listed below in chronological order in Attachment 6.1b:

1. 2009 S&P TGI _Dec 21 2009 (provided Dec. 12, 2014)
2. 2009 TGI Published RR May-09 (provided Dec. 12, 2014)
3. 2010 Moody's FEI 2010 (provided Dec. 12, 2014)
4. 2010 TGI_DBRS Report July 22-10 (provided Dec. 12, 2014)
5. 2010 TGVI 2010 03 12 CO (provided Dec. 12, 2014)
6. 2011 DBRS Report for FEI 2011 09 19 (provided Dec. 12, 2014)
7. 2011 FEI 07 21 CO (provided Dec. 12, 2014)
8. 2011 FEVI 2011 08 01 Final CO (provided Dec. 12, 2014)
9. 2012 FEI 10 04 CO (provided Dec. 12, 2014)
10. 2012 FEVI 10 04 (provided Dec. 12, 2014)
11. 2012 FEI RR FINAL Feb 29 2012 (provided Dec. 12, 2014)
12. 2013 FEI Opinion 06-26 (provided Dec. 12, 2014)
13. 2013 FEVI Opinion 06-26 (provided Dec. 12, 2014)
14. 2013 FEI DBRS Final (provided Dec. 12, 2014)
15. 2014 FEI RR DBRS March 18, 2014 Final (provided Dec. 12, 2014)
16. 2014 FEI Moody's (provided Dec. 12, 2014)
17. 2014 FEVI Moody's (provided Dec. 12, 2014)
18. FEI ROE-COC_Appendix A – Business Risk Draft (provided Apr. 22, 2015)
19. FEI-FBC 2014-2018 PBR Decisions High-Level Summary (provided Aug. 19, 2015)
20. 2015 FEI DBRS Credit Report Jan 2015 (provided Aug. 26, 2015)
21. 2015 FEI Moody's Report July 2015 (provided Aug. 26, 2015)
22. FEI Draft Evidence and Business Risk (provided Sept. 15, 2015)

c) Please indicate any substantive differences in the judgement of FEI and Mr. Coyne in terms of FEI's business risk

Response:

Although the focus of Mr. Coyne's and the Company's risk evidence differ, he does not believe there are any substantive differences between his assessment of FEI's business risk and the Company's assessment of its business risk in its evidence filed in this proceeding. Mr. Coyne's risk analysis focuses extensively on the relative risk of FEI in comparison to the Canadian and U.S. proxy group companies. FEI's business risk analysis focuses on the Company's change in business risk since its last cost of capital filing in 2012, and the impacts of amalgamation.

6.2 Please explain in detail why Mr. Coyne has not included any information related to ROE variability for his proxy samples to compare with FEI, taking into account that the BCUC has indicated that risk is the probability of not meeting cash flow targets or the allowed ROE.

Response:

Mr. Coyne assumes the question relates to volatility in earned ROEs. He finds the following reflective of the position taken by the BCUC on the relevance of allowed vs. earned ROEs:

> *The Commission Panel concludes that debt and equity investors, who in their risk assessment consider both long and short-term cash flows as well as risk of financial disruption, will derive some comfort from the track record of FEI. However, there is no evidence to suggest they are likely to make a major distinction between short-term and long-term risk. Accordingly, the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings, and management's proactive approach.*[14]

The risk analysis provided in section VI. and Appendix A of Mr. Coyne's evidence present a complete profile of the proxy group companies for this very purpose—to examine the risk protection afforded to each of the proxy companies that would lead to variability in earned ROEs.

[14] GCOC Decision, Op. Cit., p. 23.

Attachment 2.4

Blue Chip Economic Indicators®

Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead

Vol. 40, No. 9, September 10, 2015

Wolters Kluwer

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Consensus Looks For Solid GDP Growth, Tighter Labor Markets, Rebound In Inflation

Domestic Commentary The consensus continues to predict moderately above-trend, inflation-adjusted (real) economic growth over the second half of this year and all of next, according to our September 3rd-4th survey. Labor markets conditions are expected to continue tightening over the forecast horizon. The pace of job growth will likely slow somewhat from that witnessed over the past couple of years as the poll of skilled workers diminishes, but wage gains are expected to modestly accelerate. Inflation is forecast to rebound from the extreme lows recently witnessed, according to the consensus, gradually lifting toward the Federal Reserve's target for the personal consumption deflator by the end of next year. With the unemployment rate now flirting with the Fed's estimate of NAIRU (non-accelerating inflation rate of unemployment) and confidence among policymakers building that recent extreme softness in inflation will prove to be transitory, most all of our panelists still believe the Federal Open Market Committee will begin to hike interest rates by the end of this year. However, only a bare majority now believe lift-off will occur at the FOMC's mid-September meeting. By the end of 2016, the consensus predicts the mid-point of the federal funds rate target range will be in the vicinity of 1.5%, about 20 basis points lower than predicted last month.

The consensus forecast of year-over-year (y/y) real GDP growth in 2015 rebounded by 0.2 of a percentage point to 2.5% over the past month, while the forecast of GDP growth measured on a fourth quarter-over-fourth quarter basis (q4/q4) rose by 0.3 of a point to 2.4% (q/q,saar). The increases occurred despite a 0.2 of a percentage point decline this month to 2.5% (q/q,saar) in the forecast of real GDP's growth rate in Q3 and a 0.1 of a point drop in the forecast of Q4's rate of growth to 2.7%. More than offsetting these was an especially large 1.4 percentage point upward revision to 3.7% (q/q,saar) by the Bureau of Economic Analysis (BEA) in its second estimate of real GDP growth during Q2. The current consensus forecast would leave real GDP growth this year virtually identical to that in 2014 when it grew 2.4% y/y and 2.5% q4/q4.

The upward revision in BEA's estimate of Q2 real GDP was not only larger than anticipated by most analysts, but broader-based. Growth in real personal consumption expenditures (PCE) was revised up by 0.2 of a percentage point to 3.1% (q/q,saar). More impressively, growth in real nonresidential fixed investment was revised up to 3.2% (q/q,saar) versus the prior estimate of a 0.6% contraction. Growth in real residential investment was revised up by 1.2 percentage points to 7.8% (q/q,saar), while government spending and investment now is estimated to have grown 2.6% (q/q,saar), compared to the prior estimate of just 0.8%. Real net exports added 0.2 of a percentage point to real GDP's growth rate last quarter, 0.1 of a point more than first estimated. Private inventories are now estimated to have contributed 0.2 of a percentage point to real GDP's growth rate last quarter versus BEA's initial estimate that they had subtracted slightly from GDP.

In the second half of this year, the consensus predicts real GDP will be supported by the continuation of healthy real PCE growth, further improvement in capital spending, solid construction activity, and more government spending and investment. Real PCE is predicted by the consensus to grow 3.0% (q/q,saar) in both Q3 and Q4. Car and light trucks sales have been especially robust this year and in August jumped to their highest annualized rate since July 2005. Housing starts in July stood at the highest level since October 2007 and on a y/y basis were up 10.1%, lifted in large part by 19.0% y/y growth in starts of single-family homes. Residential investment is being aided by a continued loosening of lending standards and faster household formation. Over the three months ending in July, total construction spending was running at an annualized rate of almost 16%. The latest data on core capital goods orders and shipments also suggests that growth in equipment spending will improve in the second half of this year after essentially failing to make any headway over the prior three quarters. Moreover, investment in business structures, hurt by cutbacks in oil patch, is likely to ease as prices for oil stabilize. Government consumption and investment should also continue making contributions to GDP growth in the second half of this year, albeit not at the pace seen in Q2 when it grew at its fastest quarterly pace in five years.

Trade and inventories, on the other hand, are widely expected to hold down the pace of real GDP growth in the second half of this year. The trade-weighted value of the dollar has risen considerably over the past year, and combined with more sluggish-than-expected growth abroad, has served to depress exports. At the same time, solid, if not spectacular U.S. demand has lifted imports, producing a widening of the real net export deficit that is likely to persist well into 2016. Private inventories increased sharply during the first half of this year, contributing nearly 0.9 of a percentage point to real GDP's growth rate in Q1 and about 0.2 of a point to its growth rate in Q2. The consensus believes inventories stand at an unsustainable level and will be pared during the second half, subtracting more than 1.0 percentage point from real GDP's growth rate this quarter and somewhat less than that in Q4.

For all of 2015, real PCE still is expected to increase 3.0% y/y, supported by a 3.2% increase in real disposable personal income (DPI). Car and light truck sales now are expected to total 17.1 million units while housing starts are forecast to reach 1.13 million units, both estimates up slightly from a month ago. The consensus estimate of y/y growth in real nonresidential fixed investment jumped 0.6 of a percentage point over the past month to 3.4%, but the estimate of the y/y change in pre-tax corporate profits fell 0.8 of a point to 0.6%. Industrial production is forecast to increase only 1.8% y/y this year, down another 0.1 of a point over the past month, the gain held in check by the expected retrenchment in inventory levels in the second half of the year. The real net export deficit is forecast to widen to $539.0 billion from $442.0 billion in 2014. For a third straight month, the consensus forecast that the unemployment rate will average 5.3% this year. The GDP price index still is expected to increase 1.1% y/y, but the Consumer Price Index (CPI) is projected to increase just 0.2% y/y, 0.1 of a percentage point less than last month. The consensus forecast of its q4/q4 change slipped 0.2 of a percentage point to 0.7%.

The consensus forecast of y/y and q4/q4 real GDP growth in 2016 remained at 2.7% this month. Also unchanged were forecasts that real PCE and real DPI will increase 2.9% and 2.6%, respectively. Real nonresidential investment is forecast to increase 4.8% y/y, 0.1 of a percentage point more than predicted a month ago. Forecasts of total vehicle sales and housing starts also inched up to 17.2 million units and 1.28 million units, respectively. Industrial production is forecast to increase 2.6% y/y, down 0.1 of a percentage point from last month. The real net export deficit will widen to $569.1 billion in 2016, says the consensus, but that is less than forecast a month earlier. The unemployment rate is forecast to average 4.8% next year, 0.1 of a percentage point less than estimated a month ago. The CPI is predicted to increase 2.0% on a y/y basis next year, 0.1 of a percentage point less than last month, but the forecast of its q4/q4 change remained at 2.2%. The GDP price index is forecast to increase 1.9% y/y and 2.0% q4/q4, the same as predicted a month ago.

International Commentary Consensus forecasts of real GDP growth this year in many of the other nations we collect forecasts for fell over the past month, the declines largely the result of weaker-than-expected growth last quarter. All are forecast to register stronger growth in 2016. The current recessions in Russia and Brazil are now expected to be deeper than forecast a month ago. Real GDP contracted slightly in Canada during the first two quarters of this year, but the economy is expected to bounce back in the second half *(see pages 6-7).*

Special Questions Panelists are pretty evenly split on whether decreased demand or increased supply was the bigger contributor to the sharp decline in commodity prices since 2011. Not quite 58% of the panelists think the FOMC will hike rates in September *(see page 14).*

GREEN indicates the Blue Chip consensus forecast of real GDP growth over the next four quarters is 3.0 percent or more.
YELLOW cautions that the consensus forecast of real GDP growth over the next four quarters is between 1.5 percent and 2.9 percent.
RED warns that the consensus forecast of real GDP growth of real GDP growth over the next four quarters is less than 1.5 percent.

2015 Real GDP Forecast Rebounds To 2.5%

SEPTEMBER 2015 Forecast For 2015 SOURCE:	Percent Change 2015 From 2014 (Full Year-Over-Prior Year) 1 Real GDP (Chained) (2009$)	2 GDP Price Index	3 Nominal GDP (Cur.$)	4 Consumer Price Index	5 Indust. Prod. (Total)	6 Dis. Pers. Income (2009$)	7 Personal Cons. Exp. (2009$)	8 Non-Res. Fix. Inv. (2009$)	9 Corp. Profits (Cur.$)	Average For 2015 10 Treas. Bills 3-mo.	11 Treas. Notes 10-Year	12 Unempl. Rate (Civ.)	Total Units-2015 13 Housing Starts (Mil.)	14 Auto&Light Truck Sales (Mil.)	2015 15 Net Exports (2009$)
Societe Generale	2.7 H	1.1	3.8	0.2	1.9	3.2	3.1	3.4	0.8	0.2 H	2.3	5.2	1.15	17.1	-540.0
Action Economics	2.6	1.0	3.6	0.2	1.8	3.3	3.1	3.3	0.0	0.1	2.2	5.3	1.15	17.2	-525.9
Bank of America Merrill Lynch	2.6	1.1	3.7	0.1	1.8	na	3.1	3.7	na	0.0 L	2.4 H	5.3	1.13	17.2	-535.6
BMO Capital Markets*	2.6	1.1	3.8	0.2	1.8	3.3	3.1	3.5	-0.3	0.1	2.2	5.3	1.12	17.2	-540.0
Credit Suisse	2.6	1.1	3.7	0.2	2.0	na	3.1	3.4	1.5	na	2.3	5.3	1.06 L	na	-530.1
Ford Motor Company*	2.6	1.1	3.8	0.4 H	1.7	3.6	3.1	2.7	na	0.0 L	2.3	5.3	1.18	na	-530.8
MUFG Union Bank	2.6	1.2	3.8	0.4 H	1.8	na	2.9	4.0 H	1.0	0.1	2.3	5.3	1.20	17.0	-540.0
Naroff Economic Advisors*	2.6	1.3 H	4.0 H	0.3	1.9	3.8 H	3.1	3.4	8.9 H	0.1	2.3	5.3	1.22 H	17.1	-538.0
National Assn. of Home Builders	2.6	1.2	3.8	0.4 H	2.0	3.0	3.1	3.3	na	0.2 H	2.2	5.4	1.10	16.9	-534.0
PNC Financial Services Group	2.6	1.0 L	3.6	0.3	1.8	3.2	3.0	3.5	na	0.1	2.2	5.3	1.12	17.2	-535.5
RBC Capital Markets	2.6	1.1	3.8	0.2	2.3	na	3.0	3.3	na	0.2 H	2.3	5.2	1.12	17.1	-523.0 H
RBS	2.6	1.0 L	3.6	0.2	1.8	3.2	3.0	3.9	1.0	0.1	2.2	5.3	1.10	17.2	-534.5
RDQ Economics	2.6	1.1	3.7	0.3	1.7	3.0	3.0	3.5	-0.5	0.1	2.3	5.3	1.10	17.0	-537.4
Swiss Re	2.6	1.1	3.8	0.2	1.9	3.2	3.0	3.7	4.3	0.2 H	2.3	5.3	1.18	17.0	-538.6
Turning Points (Micrometrics)	2.6	1.1	3.7	0.3	na	2.8 L	3.1	3.8	0.0	0.2 H	2.2	5.4	1.10	17.0	-533.0
UBS	2.6	1.2	3.8	0.3	1.8	2.9	3.0	3.4	na	0.2 H	2.3	5.3	1.14	na	-533.9
Wells Capital Management	2.6	1.2	3.8	0.4 H	1.9	3.1	3.1	3.5	-0.9	0.1	2.1 L	5.4	1.13	17.0	-535.0
ACT Research	2.5	1.2	3.7	0.3	1.7	3.1	3.0	3.4	na	0.1	2.3	5.2	1.16	17.2	-548.9
Barclays*	2.5	1.0 L	3.6	0.1	1.6	na	3.0	3.3	na	na	2.2	5.3	1.11	na	-542.4
Conference Board*	2.5	1.1	3.6	0.3	1.9	3.1	3.0	3.5	-1.0	0.1	2.2	5.3	1.12	16.9	-539.4
Daiwa Capital Markets America	2.5	1.1	3.6	0.2	1.9	3.2	3.0	3.5	-0.9	0.1	2.2	5.3	1.10	17.0	-536.0
Eaton Corporation	2.5	1.1	3.7	0.2	2.0	3.1	3.1	2.9	7.2	0.2 H	2.4 H	5.2	1.14	17.3 H	-539.6
Economist Intelligence Unit	2.5	1.1	3.6	0.3	1.7	3.0	3.0	2.8	na	0.2 H	2.3	5.2	1.15	16.8	-535.0
Fannie Mae	2.5	1.1	3.7	0.3	2.0	3.1	3.0	3.4	-1.3	0.1	2.2	5.1 L	1.11	17.2	-536.0
FedEx Corporation	2.5	1.0 L	3.5	0.3	1.8	3.2	3.0	3.4	0.0	0.1	2.2	5.4	1.14	17.0	-539.0
General Motors	2.5	1.1	3.6	0.2	1.7	3.2	3.1	3.4	-1.7	0.1	2.2	5.3	1.11	na	-532.4
Georgia State University*	2.5	1.1	3.6	0.2	1.7	3.1	3.0	3.8	0.8	0.2 H	2.3	5.4	1.10 `	17.0	-548.1
Goldman Sachs & Co.**	2.5	1.0 L	3.5	0.2	1.9	3.1	3.1	3.6	na	0.2 H	2.3	5.4	1.12	na	-542.7
High Frequency Economics	2.5	1.1	3.7	0.4 H	1.6	3.1	3.0	3.5	-0.5	0.2 H	2.3	5.3	1.13	17.2	-550.4
IHS Global Insight	2.5	1.1	3.7	0.1	1.3 L	3.4	3.1	3.9	1.2	0.1	2.2	5.4	1.13	17.2	-550.0
Inforum - Univ. of Maryland	2.5	1.1	3.7	0.3	1.9	3.1	3.0	3.5	1.4	0.2 H	2.3	5.3	1.14	16.9	-538.3
J P MorganChase	2.5	1.1	3.6	0.2	2.0	3.1	3.0	3.0	-0.3	na	2.2	5.3	1.11	17.0	-544.5
Macroeconomic Advisers, LLC**	2.5	1.1	3.6	0.2	1.6	3.2	3.0	3.3	-1.9	0.1	2.2	5.3	1.11	17.1	-530.7
MacroFin Analytics	2.5	1.1	3.6	0.1	1.9	3.0	3.0	3.3	-0.7	0.2 H	2.2	5.3	1.13	17.0	-525.0
Mesirow Financial	2.5	1.1	3.6	0.2	1.6	3.2	3.0	3.2	-1.5	0.0 IL	2.2	5.3	1.12	17.0	-535.6
National Assn. of Realtors	2.5	1.1	3.7	0.3	1.7	3.2	3.2	2.3 L	1.9	0.1	2.2	5.3	1.13	17.0	-540.0
Nomura Securities	2.5	1.1	3.6	0.2	1.8	3.2	3.1	3.6	na	0.1	2.2	5.3	1.06 L	17.0	-552.2
Northern Trust Company*	2.5	1.0 L	3.6	0.2	1.8	3.1	3.0	3.5	na	0.1	2.2	5.3	1.10	17.1	-538.7
Point72 Asset Management	2.5	1.1	3.6	0.4 H	1.9	3.1	3.0	3.6	0.4	0.1	2.2	5.2	1.15	17.1	-535.3
SOM Economics, Inc.	2.5	1.0 L	3.5	0.3	2.0	3.3	3.0	3.1	0.1	0.1	2.2	5.3	1.12	17.2	-530.0
U.S. Chamber of Commerce	2.5	1.1	3.7	0.2	1.6	3.1	3.1	3.3	1.8	0.1	2.3	5.3	1.10	na	-540.5
UCLA Business Forecasting Proj.*	2.5	1.1	3.6	0.0	1.4	3.4	3.1	3.9	1.0	0.1	2.2	5.3	1.14	17.2	-556.1 L
Oxford Economics	2.5	1.0 L	3.5	0.2	1.6	3.1	3.0	3.4	1.5	0.1	2.2	5.3	1.15	17.2	-536.8
Amherst Pierpont Securities	2.4	1.1	3.6	0.2	1.6	3.2	3.0	3.5	0.0	0.1	2.3	5.3	1.15	17.1	-537.0
Comerica	2.4	1.0 L	3.3	0.3	1.4	3.5	3.1	3.4	na	0.1	2.3	5.3	1.07	17.1	-551.3
Econoclast	2.4	1.2	3.6	0.4	1.8	3.0	3.0	3.2	0.5	0.1	2.2	5.3	1.13	17.1	-541.0
Moody's Analytics	2.4	1.1	3.3	0.0	2.1	3.7	3.3 H	2.7	-4.4 L	0.1	2.3	5.3	1.18	17.1	-542.0
Moody's Capital Markets*	2.4	1.0 L	3.4	0.2	1.9	3.1	3.0	3.1	1.0	0.1	2.2	5.3	1.15	17.1	-543.0
Morgan Stanley*	2.4	1.2	3.6	0.1	1.8	3.5	3.0	3.2	-0.9	0.1	2.1 L	5.3	1.17	17.2	-546.1
Wells Fargo	2.4	1.2	3.5	0.3	1.8	3.1	3.0	3.3	3.9	0.2 H	2.3	5.3	1.14	17.1	-545.6
Standard & Poors Corp.*	2.3	1.2	3.5	-0.1 L	2.4 H	3.6	3.1	3.7	-1.5	0.1	2.2	5.4	1.14	16.7 L	-551.2
AIG	2.1 L	1.0 L	3.0 L	0.1	1.8	3.4	2.8 L	2.5	0.3	0.1	2.4 H	5.5 H	1.12	16.9	-540.8
2015 Consensus: September Avg.	**2.5**	**1.1**	**3.6**	**0.2**	**1.8**	**3.2**	**3.0**	**3.4**	**0.6**	**0.1**	**2.2**	**5.3**	**1.13**	**17.1**	**-539.0**
Top 10 Avg.	2.6	1.2	3.8	0.4	2.1	3.5	3.1	3.8	3.4	0.2	2.3	5.4	1.17	17.2	-529.5
Bottom 10 Avg.	2.4	1.0	3.4	0.1	1.5	3.0	3.0	2.8	-1.6	0.1	2.2	5.2	1.09	16.9	-550.0
August Avg.	2.3	1.1	3.4	0.3	1.9	3.2	3.0	2.8	1.4	0.2	2.3	5.3	1.12	17.0	-542.0
Historical data 2011	1.6	2.1	3.7	3.2	3.0	2.5	2.3	7.7	4.0	0.1	2.8	9.0	0.61	12.7	-459.4
2012	2.2	1.8	4.1	2.1	2.8	3.2	1.5	9.0	10.0	0.1	1.8	8.1	0.78	14.4	-447.1
2013	1.5	1.6	3.1	1.5	1.9	-1.4	1.7	3.0	2.0	0.1	2.4	7.4	0.92	15.5	-417.5
2014	2.4	1.6	4.1	1.6	3.7	2.7	2.7	6.2	1.7	0.0	2.5	6.2	1.00	16.4	-442.5
Number Of Forecasts Changed From A Month Ago:															
Down	1	9	1	21	21	8	2	5	21	14	19	18	8	2	9
Same	9	35	10	27	22	24	37	9	7	32	28	32	21	19	11
Up	42	8	41	4	8	15	13	38	10	3	4	2	23	23	32
September Median	2.5	1.1	3.6	0.2	1.8	3.2	3.0	3.4	0.1	0.1	2.2	5.3	1.13	17.1	-538.7
September Diffusion Index	89 %	49 %	88 %	34 %	37 %	57 %	61 %	82 %	36 %	39 %	35 %	35 %	64 %	74 %	72 %

***Former winner of annual Lawrence R. Klein Award for Blue Chip Forecast Accuracy. **Denotes two-time winner. ***Denotes three-time winner.**

2016 Real GDP Forecast Stays At 2.7%

SEPTEMBER 2015 Forecast For 2016 SOURCE:	Percent Change 2016 From 2015 (Full Year-Over-Prior Year) 1 Real GDP (Chained) (2009$)	2 GDP Price Index	3 Nominal GDP (Cur.$)	4 Consumer Price Index	5 Indust. Prod. (Total)	6 Dis. Pers. Income (2009$)	7 Personal Cons. Exp. (2009$)	8 Non-Res. Fix. Inv. (2009$)	9 Corp. Profits (Cur.$)	Average For 2016 10 Treas. Bills 3-mo.	11 Treas. Notes 10-Year	12 Unempl. Rate (Civ.)	Total Units-2016 13 Housing Starts (Mil.)	14 Auto&Light Truck Sales (Mil.)	2016 15 Net Exports (2009$)
Moody's Analytics	3.4 H	2.0	5.2	2.0	1.9	4.4 H	4.3 H	5.6	6.7	1.1	3.2	4.9	1.58 H	16.8	-601.6
Naroff Economic Advisors*	3.2	2.7 H	6.0 H	2.6	3.1	3.0	3.0	5.5	6.8	1.1	3.3	4.8	1.36	17.0	-580.0
Swiss Re	3.1	1.3	4.5	1.6	2.7	3.0	2.9	6.8	5.4	1.5	3.2	4.8	1.47	16.7	-607.6
UCLA Business Forecasting Proj.*	3.1	2.1	5.3	2.2	2.2	3.1	3.2	6.5	10.7 H	1.0	3.2	4.9	1.42	17.6	-622.1
Bank of America Merrill Lynch	3.0	1.7	4.8	1.8	3.3	na	3.1	5.3	na	1.3	2.9	4.9	1.28	18.1 H	-558.5
National Assn. of Home Builders	3.0	2.2	5.2	2.1	3.6	2.7	3.1	4.3	na	1.1	2.8	5.1	1.29	16.9	-542.0
RBC Capital Markets	3.0	2.2	5.3	2.1	5.1 H	na	2.6	4.5	na	1.1	3.1	4.1 L	1.20	17.3	-485.0 H
Societe Generale	3.0	2.0	5.0	1.7	2.5	3.2	2.8	4.0	1.3	1.0	2.9	4.6	1.32	17.5	-577.9
Credit Suisse	2.9	1.6	4.5	1.5	3.6	na	3.1	4.0	4.8	na	2.8	4.7	1.15	na	-556.9
MUFG Union Bank	2.9	2.5	5.4	2.8 H	2.3	na	2.9	7.0 H	7.0	1.3	3.2	4.6	1.50	17.3	-580.0
RBS	2.9	1.5	4.5	2.0	2.4	2.7	2.8	6.0	4.0	1.2	2.7	4.8	1.30	16.8	-531.0
Turning Points (Micrometrics)	2.9	1.8	4.7	2.2	na	2.5	2.9	3.3	4.1	0.8	2.8	5.2	1.11	17.4	-523.5
Wells Capital Management	2.9	2.3	5.2	2.0	3.4	2.6	2.8	5.1	4.1	0.8	2.3 L	5.1	1.20	16.8	-550.0
Oxford Economics	2.8	1.7	4.6	1.9	2.5	2.7	3.0	5.2	3.9	0.7	2.6	4.8	1.36	17.3	-558.7
ACT Research	2.8	2.1	4.9	2.2	2.1	2.1	2.6	6.5	na	1.0	2.7	4.7	1.29	17.8	-594.3
Comerica	2.8	1.8	4.6	2.2	3.9	2.7	2.4	6.2	na	0.8	3.0	4.7	1.16	16.8	-582.0
FedEx Corporation	2.8	1.7	4.4	2.0	2.8	2.6	2.8	4.8	4.6	1.1	3.0	5.0	1.33	17.2	-557.2
IHS Global Insight	2.8	1.7	4.6	1.6	1.6 L	3.3	3.2	6.3	9.0	0.8	2.6	5.2	1.31	17.5	-618.2
National Assn. of Realtors	2.8	1.9	4.7	2.4	2.6	2.4	3.3	3.6	2.4	1.2	3.0	5.0	1.30	16.8	-540.0
Northern Trust Company*	2.8	1.8	4.7	2.0	2.7	2.8	2.8	4.6	na	0.5 L	2.6	5.0	1.25	17.1	-543.0
RDQ Economics	2.8	1.9	4.8	2.2	2.1	2.4	2.8	5.0	4.2	1.6 H	3.4	4.5	1.15	17.5	-565.5
SOM Economics, Inc.	2.8	1.2 L	4.0	1.4	2.8	2.9	2.8	3.4	4.0	0.9	2.7	4.5	1.22	17.8	-521.0
UBS	2.8	2.3	5.1	2.4	2.0	1.7 L	3.0	6.8	na	1.4	2.7	4.8	1.31	na	-579.8
Action Economics	2.7	1.5	4.2	1.8	2.5	3.1	3.0	4.3	2.9	1.0	2.6	5.0	1.22	17.6	-527.0
Ford Motor Company*	2.7	2.0	4.9	2.5	1.9	2.3	3.1	3.6	na	1.2	2.9	5.0	1.33	na	-526.0
General Motors	2.7	1.7	4.4	1.6	2.0	2.6	2.8	3.6	0.6	0.9	3.2	4.8	1.31	na	-561.2
Inforum - Univ. of Maryland	2.7	1.9	4.7	2.2	3.0	2.6	2.9	5.0	5.4	1.3	3.1	4.9	1.30	17.1	-561.5
MacroFin Analytics	2.7	1.7	4.4	2.0	3.6	2.2	2.7	4.8	5.0	1.2	3.2	5.0	1.10 L	16.5	-503.8
Standard & Poors Corp.*	2.7	2.1	4.9	2.2	2.9	2.3	3.0	5.1	1.4	0.9	2.8	5.1	1.35	16.9	-584.6
U.S. Chamber of Commerce	2.7	1.8	4.6	2.0	2.6	2.4	2.9	4.5	4.0	1.1	3.0	5.0	1.25	na	-576.9
Amherst Pierpont Securities	2.6	2.1	4.8	2.6	2.2	2.8	2.6	4.8	5.5	1.4	3.8 H	4.7	1.41	17.3	-547.0
BMO Capital Markets*	2.6	2.1	4.8	2.2	2.4	2.6	2.9	4.5	5.0	0.9	2.7	4.7	1.34	17.4	-595.0
Daiwa Capital Markets America	2.6	1.9	4.5	2.0	2.5	2.8	2.8	5.5	2.0	1.0	2.9	4.9	1.16	17.0	-610.0
Eaton Corporation	2.6	1.6	4.1	1.7	2.8	2.6	3.2	3.4	5.4	0.8	2.8	4.9	1.20	17.5	-578.2
Economist Intelligence Unit	2.6	2.0	4.5	1.8	2.8	2.4	2.6	5.4	na	1.1	2.9	4.9	1.25	17.0	-560.0
Georgia State University*	2.6	2.0	4.6	2.0	3.2	2.8	2.7	5.7	9.3	1.1	2.9	5.2	1.20	16.5	-601.7
High Frequency Economics	2.6	2.3	5.0	2.5	1.8	2.5	2.7	4.8	3.0	1.5	3.3	4.5	1.27	17.7	-573.7
Macroeconomic Advisers, LLC**	2.6	1.7	4.3	1.6	1.8	2.5	3.3	3.4	0.2	1.0	3.3	4.9	1.30	17.1	-533.3
Mesirow Financial	2.6	1.7	4.3	1.7	1.7	2.4	3.3	3.1	0.9	0.6	3.2	4.9	1.32	16.5	-562.3
Nomura Securities	2.6	1.6	4.1	2.0	1.9	3.0	2.8	5.7	na	0.9	2.7	5.0	1.23	17.3	-622.1
PNC Financial Services Group	2.6	1.8	4.4	2.2	2.0	2.7	2.6	4.0	na	0.8	2.5	4.8	1.21	17.5	-535.8
Point72 Asset Management	2.6	1.8	4.5	2.2	3.1	2.4	2.6	5.7	2.6	1.2	3.0	4.3	1.25	17.2	-572.6
AIG	2.5	1.7	4.3	1.9	2.0	2.0	2.7	2.6 L	2.9	1.4	3.2	5.3 H	1.34	16.7	-530.5
Barclays*	2.5	1.7	4.3	1.4 L	2.1	na	2.8	4.9	na	na	na	4.5	1.24	na	-577.4
Fannie Mae	2.5	1.7	4.3	1.9	2.5	2.1	2.8	3.9	2.2	0.7	2.4	4.9	1.31	17.5	-568.0
J P MorganChase	2.5	1.9	4.4	2.0	2.4	2.4	2.8	5.0	5.3	na	na	4.7	1.20	17.4	-594.3
Moody's Capital Markets*	2.5	1.7	4.2	1.7	3.6	2.1	2.7	3.1	1.5	0.6	2.6	4.8	1.27	17.1	-576.0
Wells Fargo	2.5	1.9	4.4	2.2	3.0	2.6	2.8	5.0	6.7	1.2	2.7	4.9	1.25	17.1	-634.4
Conference Board*	2.4	1.9	4.3	2.0	2.6	2.5	2.5	4.4	0.0 L	0.7	2.8	4.7	1.32	16.4 L	-566.0
Goldman Sachs & Co.**	2.4	1.4	3.9 L	2.1	3.2	2.4	3.0	4.7	na	1.1	2.8	5.0	1.28	na	-661.0 L
Econoclast	2.2	2.3	4.5	2.3	2.5	2.4	2.6	3.9	4.5	0.8	2.6	5.0	1.23	17.2	-580.0
Morgan Stanley*	1.9 L	2.0	3.9 L	1.5	1.7	2.4	2.3 L	3.1	1.7	0.9	na	4.9	1.43	17.4	-595.2
2016 Consensus: September Avg.	**2.7**	**1.9**	**4.6**	**2.0**	**2.6**	**2.6**	**2.9**	**4.8**	**4.1**	**1.0**	**2.9**	**4.8**	**1.28**	**17.2**	**-569.1**
Top 10 Avg.	3.1	2.3	5.3	2.5	3.7	3.2	3.3	6.4	7.3	1.4	3.3	5.1	1.42	17.7	-521.7
Bottom 10 Avg.	2.4	1.5	4.1	1.6	1.8	2.2	2.5	3.3	1.2	0.7	2.6	4.5	1.16	16.7	-617.4
August Avg.	2.7	1.9	4.7	2.1	2.7	2.6	2.9	4.7	4.0	1.1	2.9	4.9	1.27	17.1	-573.7
Number Of Forecasts Changed From A Month Ago:															
Down	8	19	20	27	16	7	9	11	14	22	19	20	9	8	17
Same	24	26	16	18	21	23	24	13	10	24	24	29	26	24	12
Up	19	6	15	6	13	16	18	27	13	2	5	2	16	11	22
September Median	2.7	1.9	4.5	2.0	2.5	2.6	2.8	4.8	4.1	1.0	2.9	4.9	1.28	17.2	-570.3
September Diffusion Index	61 %	37 %	45 %	29 %	47 %	60 %	59 %	66 %	49 %	29 %	35 %	32 %	57 %	53 %	55 %

***Former winner of annual Lawrence R. Klein Award for Blue Chip Forecast Accuracy. **Denotes two-time winner. ***Denotes three-time winner.**

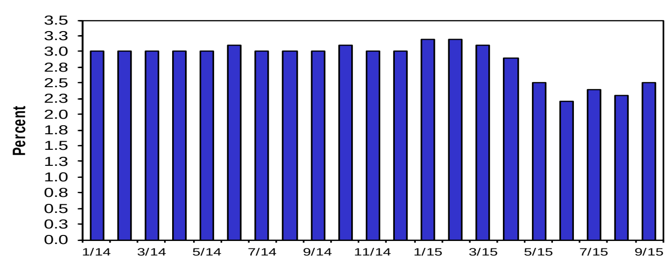
BASIC DATA SOURCES: [1]Gross Domestic Product (GDP), chained 2009$, National Income and Product Accounts (NIPA), Bureau of Economic Analysis (BEA); [2]GDP Chained Price Index, NIPA, BEA; [3]GDP, current dollars, NIPA, BEA; [4]Consumer Price Index-All Urban Consumers, Bureau of Labor Statistics (BLS); [5]Total Industrial Production, Federal Reserve Board (FRB); [6]Disposable Personal Income, 2009$, NIPA, BEA; [7]Personal Consumption Expenditures, 2009$, NIPA, BEA; [8]Nonresidential Fixed Investment, 2009$, NIPA, BEA; [9]Corporate Profits Before Taxes, current dollars, with inventory valuation and capital consumption adjustments, NIPA, BEA; [10]Treasury Bill Rate, 3-month, secondary market, bank discount basis, FRB; [11]Treasury note yield, 10-year, constant maturity basis, FRB; [12]Unemployment Rate, civilian work force, BLS; [13]Housing Starts, Bureau of Census; [14]Total U.S. Auto and Light Truck Sales (includes imports), BEA; [15]Net Exports of Goods and Services, 2009$, NIPA, BEA.

Previous Consensus Forecasts

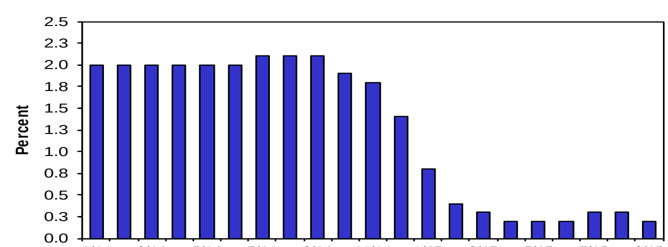
Consensus Forecasts For 2015	Real GDP Chained ('2009$)	GDP Price Index	Nominal GDP (Cur. $)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income ('2009$)	Personal Cons. Exp. ('2009$)	Non-Res. Fix. Inv. ('2009$)	Corp. Profits (Cur. $)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto/Truck Sales (Mil.)	Net Exports ('2009$)
January 2014 Consensus	3.0	1.9	4.9	2.0	3.5	2.8	2.8	5.4	5.0	0.5	3.7	6.3	1.30	16.5	-418.5
February 2014 Consensus	3.0	1.9	4.9	2.0	3.5	2.8	2.8	5.6	5.1	0.5	3.7	6.1	1.31	16.4	-388.2
March 2014 Consensus	3.0	1.9	4.9	2.0	3.6	2.8	2.8	5.7	5.4	0.5	3.7	5.9	1.31	16.4	-392.9
April 2014 Consensus	3.0	1.9	4.9	2.0	3.6	2.9	2.9	5.7	5.6	0.5	3.7	5.9	1.31	16.4	-398.5
May 2014 Consensus	3.0	1.9	4.9	2.0	3.6	2.9	2.9	5.7	5.2	0.5	3.6	5.9	1.27	16.4	-410.7
June 2014 Consensus	3.1	1.9	5.0	2.0	3.6	2.9	2.8	5.7	6.0	0.5	3.5	5.8	1.26	16.5	-421.4
July 2014 Consensus	3.0	1.9	5.0	2.1	3.6	2.8	2.8	5.6	5.8	0.5	3.5	5.8	1.23	16.6	-436.4
August 2014 Consensus	3.0	1.9	5.0	2.1	3.7	2.8	2.8	5.5	5.8	0.5	3.4	5.7	1.20	16.7	-456.4
September 2014 Consensus	3.0	2.0	5.0	2.1	3.6	2.8	2.7	5.7	6.4	0.5	3.3	5.7	1.20	16.7	-455.1
October 2014 Consensus	3.1	1.9	5.0	1.9	3.5	2.9	2.7	6.0	6.6	0.5	3.2	5.6	1.19	16.8	-450.1
November 2014 Consensus	3.0	1.8	4.8	1.8	3.6	2.8	2.7	5.8	6.5	0.4	3.0	5.6	1.18	16.8	-436.1
December 2014 Consensus	3.0	1.7	4.7	1.4	3.5	2.9	2.8	5.9	7.0	0.4	2.9	5.5	1.17	16.8	-448.2
January 2015 Consensus	3.2	1.5	4.7	0.8	3.8	3.1	3.0	5.9	7.0	0.4	2.7	5.5	1.17	16.9	-457.3
February 2015 Consensus	3.2	1.1	4.3	0.4	3.9	3.3	3.3	5.1	6.3	0.4	2.4	5.4	1.16	16.9	-475.5
March 2015 Consensus	3.1	1.1	4.3	0.3	3.8	3.5	3.3	5.3	5.6	0.3	2.4	5.4	1.16	16.9	-491.2
April 2015 Consensus	2.9	1.1	4.0	0.2	3.1	3.5	3.2	5.0	4.3	0.3	2.3	5.4	1.14	16.8	-493.5
May 2015 Consensus	2.5	1.0	3.5	0.2	2.5	3.5	3.1	3.5	3.3	0.2	2.2	5.4	1.11	16.8	-522.2
June 2015 Consensus	2.2	1.0	3.3	0.2	2.3	3.4	2.9	3.6	1.4	0.2	2.3	5.4	1.10	16.9	-542.5
July 2015 Consensus	2.4	1.0	3.4	0.3	2.0	3.4	3.0	3.5	1.3	0.2	2.3	5.3	1.11	16.9	-547.7
August 2015 Consensus	2.3	1.1	3.4	0.3	1.9	3.2	3.0	2.8	1.4	0.2	2.3	5.3	1.12	17.0	-542.0
September 2015 Consensus	**2.5**	**1.1**	**3.6**	**0.2**	**1.8**	**3.2**	**3.0**	**3.4**	**0.6**	**0.1**	**2.2**	**5.3**	**1.13**	**17.1**	**-539.0**
Change From Jan. 2014 Forecast	-0.5	-0.8	-1.3	-1.8	-1.7	0.4	0.2	-2.0	-4.4	-0.4	-1.5	-1.0	-0.17	0.6	-120.5
Forecast High	3.2	2.0	5.0	2.1	3.9	3.5	3.3	6.0	7.0	0.5	3.7	6.3	1.31	17.1	-388.2
Forecast Low	2.2	1.0	3.3	0.2	1.8	2.8	2.7	2.8	0.6	0.1	2.2	5.3	1.10	16.4	-547.7

Consensus Forecasts For 2016	Real GDP Chained ('2009$)	GDP Price Index	Nominal GDP (Cur. $)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income ('2009$)	Personal Cons. Exp. ('2009$)	Non-Res. Fix. Inv. ('2009$)	Corp. Profits (Cur. $)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto/Truck Sales (Mil.)	Net Exports ('2009$)
January 2015 Consensus	2.9	2.0	4.9	2.3	3.3	2.8	2.7	5.4	4.1	1.7	3.5	5.1	1.30	17.0	-480.4
February 2015 Consensus	2.9	2.0	4.9	2.3	3.3	2.8	2.8	5.2	4.1	1.6	3.2	5.0	1.30	17.1	-499.5
March 2015 Consensus	2.9	1.9	4.8	2.2	3.2	2.7	2.8	5.2	4.1	1.6	3.2	5.0	1.30	17.0	-523.7
April 2015 Consensus	2.8	1.9	4.8	2.2	3.1	2.6	2.8	5.2	4.0	1.4	3.1	5.0	1.28	17.0	-530.0
May 2015 Consensus	2.8	1.9	4.8	2.2	3.1	2.5	2.8	5.0	3.9	1.3	3.0	5.0	1.26	17.1	-544.4
June 2015 Consensus	2.8	1.9	4.8	2.2	3.0	2.5	2.8	5.0	4.4	1.2	3.0	4.9	1.26	17.1	-573.8
July 2015 Consensus	2.8	1.9	4.8	2.2	2.9	2.5	2.8	4.9	4.1	1.2	3.0	4.9	1.27	17.1	-578.5
August 2015 Consensus	2.7	1.9	4.7	2.1	2.7	2.6	2.9	4.7	4.0	1.1	2.9	4.9	1.27	17.1	-573.7
September 2015 Consensus	**2.7**	**1.9**	**4.6**	**2.0**	**2.6**	**2.6**	**2.9**	**4.8**	**4.1**	**1.0**	**2.9**	**4.8**	**1.28**	**17.2**	**-569.1**
Change From Jan. 2015 Forecast	-0.2	-0.1	-0.3	-0.3	-0.7	-0.2	0.2	-0.6	0.0	-0.7	-0.6	-0.3	-0.02	0.2	-88.7
Forecast High	2.9	2.0	4.9	2.3	3.3	2.8	2.9	5.4	4.4	1.7	3.5	5.1	1.30	17.2	-480.4
Forecast Low	2.7	1.9	4.6	2.0	2.6	2.5	2.7	4.7	3.9	1.0	2.9	4.8	1.26	17.0	-578.5

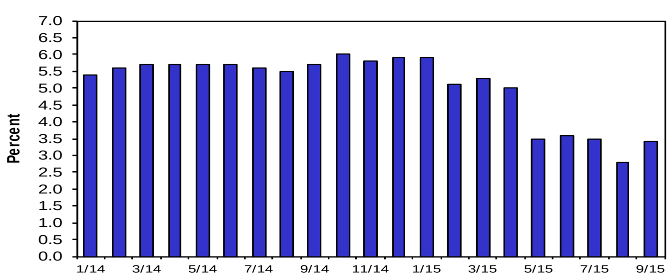
Consensus Forecasts Of Y/Y % Change In Real GDP In 2015



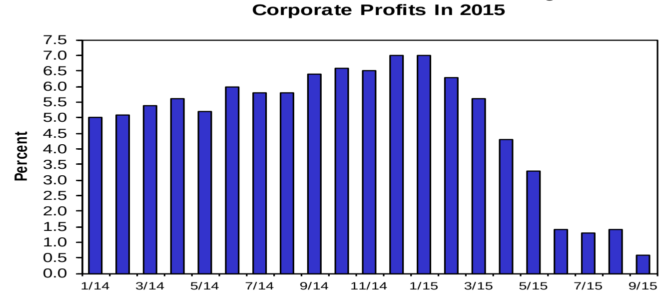
Consensus Forecasts Of Y/Y % Change In Consumer Price Index In 2015



Consensus Forecasts Of Y/Y % Change In Real Nonresidential Fixed Investment In 2015



Consensus Forecasts Of Y/Y % Change In Corporate Profits In 2015



3. Blue Chip Consensus: Percent Change From Prior Quarter At Annual Rate And Averages For Quarter.*

Actuals[1]	Real GDP	GDP Price Index	CPI	Producer Price Index	Total Industrial Production	Disposable Personal Income	Personal Consump. Expend.	Unemploy-ment Rate	3-Mo. Treas. Bills	10-Yr. Treas. Notes	Change in Business Inventories	Real Net Exports
	% Change From Prior Quarter At Annual Rate							Average For Quarter				
2014 1Q	-0.9	1.5	2.1	2.3	3.6	4.0	1.3	6.6	0.1	2.8	36.9	-434.0
2Q	4.6	2.2	2.4	2.2	5.7	3.0	3.8	6.2	0.1	2.6	77.1	-443.3
3Q	4.3	1.6	1.2	1.2	3.9	2.7	3.5	6.1	0.0	2.6	79.9	-429.1
4Q	2.1	0.1	-0.9	-0.6	4.7	4.7	4.3	5.7	0.0	2.3	78.2	-463.6
2015 1Q	0.6	0.1	-3.1	-4.8	-0.2	3.9	1.8	5.6	0.0	2.0	112.8	-541.2
2Q	3.7	2.1	3.0	0.4	-2.0	1.3	3.1	5.4	0.0	2.2	121.1	-532.7
Blue Chip Forecasts	% Change From Prior Quarter At Annual Rate							Average For Quarter				
3Q Consensus	**2.5**	**1.8**	**1.9**	**1.5**	**2.8**	**3.0**	**3.0**	**5.2**	**0.1**	**2.3**	**88.6**	**-536.6**
Top 10 Avg.	3.1	2.4	2.6	3.4	4.1	4.4	3.5	5.3	0.3	2.4	110.1	-524.2
Bot. 10 Avg.	1.9	1.3	0.9	-1.2	1.4	2.0	2.5	5.1	0.0	2.2	68.5	-553.8
4Q Consensus	**2.7**	**1.5**	**1.3**	**0.9**	**2.7**	**2.9**	**3.0**	**5.1**	**0.3**	**2.5**	**78.9**	**-543.7**
Top 10 Avg.	3.3	2.2	2.3	2.7	4.1	4.1	3.6	5.3	0.5	2.7	101.1	-519.9
Bot. 10 Avg.	2.3	0.7	-0.2	-1.5	1.3	2.0	2.6	4.9	0.1	2.3	60.2	-567.7
2016 1Q Consensus	**2.6**	**1.9**	**1.9**	**2.1**	**2.8**	**2.6**	**2.8**	**5.0**	**0.6**	**2.6**	**71.3**	**-553.5**
Top 10 Avg.	3.1	2.4	2.7	3.0	4.5	3.6	3.4	5.2	0.9	2.9	99.4	-519.7
Bot. 10 Avg.	2.0	1.4	1.0	1.2	1.7	1.8	2.3	4.7	0.3	2.4	46.9	-586.0
2Q Consensus	**2.8**	**2.0**	**2.3**	**2.4**	**2.9**	**2.5**	**2.8**	**4.9**	**0.9**	**2.8**	**66.9**	**-565.4**
Top 10 Avg.	3.3	2.5	3.1	3.3	4.0	3.4	3.5	5.1	1.2	3.2	97.1	-523.0
Bot. 10 Avg.	2.3	1.6	1.6	1.6	1.9	1.7	2.4	4.6	0.6	2.5	39.2	-610.0
3Q Consensus	**2.7**	**2.0**	**2.3**	**2.4**	**3.0**	**2.5**	**2.7**	**4.8**	**1.1**	**3.0**	**64.1**	**-577.0**
Top 10 Avg.	3.2	2.4	2.9	3.2	4.3	3.4	3.4	5.1	1.6	3.5	95.3	-526.0
Bot. 10 Avg.	2.3	1.5	1.8	1.8	1.9	1.8	2.3	4.4	0.8	2.6	34.1	-629.2
4Q Consensus	**2.6**	**2.0**	**2.3**	**2.2**	**2.9**	**2.6**	**2.7**	**4.7**	**1.4**	**3.2**	**62.1**	**-588.5**
Top 10 Avg.	3.1	2.5	3.0	3.0	4.2	3.4	3.3	5.1	2.0	3.8	94.7	-526.0
Bot. 10 Avg.	2.1	1.4	1.8	1.4	1.8	1.9	2.2	4.3	1.0	2.7	29.7	-649.6

4. Blue Chip Consensus: Quarterly Annualized Values And Percent Change From Same Quarter In Prior Year.*

Real Gross Domestic Product

	Billions Of Chained 2009$ (SAAR)			% Change From Same Quarter **In Prior Year**[2]		
	Actual	**Forecast**[1]		Actual	**Forecast**	
Quarter	2014	2015	2016	2014	2015	2016
1Q	15724.9	16177.3	**16643.1**	1.7	2.9	**2.9**
2Q	15901.5	16324.3	**16756.4**	2.6	2.7	**2.6**
3Q	16068.8	**16425.9**	**16868.8**	2.9	**2.2**	**2.7**
4Q	16151.4	**16537.2**	**16979.0**	2.5	**2.4**	**2.7**

GDP Chained Price Index

	Index 2009 = 100 (SAAR)			% Change From Same Quarter **In Prior Year**[2]		
	Actual	**Forecast**[1]		Actual	**Forecast**	
Quarter	2014	2015	2016	2014	2015	2016
1Q	108.0	109.1	**111.1**	1.6	1.0	**1.8**
2Q	108.6	109.7	**111.7**	1.9	1.0	**1.8**
3Q	109.0	**110.2**	**112.2**	1.8	**1.0**	**1.8**
4Q	109.1	**110.6**	**112.8**	1.3	**1.4**	**2.0**

Total Industrial Production

	Index 2012 = 100 (SAAR)			% Change From Same Quarter **In Prior Year**[2]		
	Actual	**Forecast**[1]		Actual	**Forecast**	
Quarter	2014	2015	2016	2014	2015	2016
1Q	103.8	107.5	**109.1**	2.5	3.6	**1.5**
2Q	105.3	106.9	**109.9**	3.6	1.5	**2.8**
3Q	106.3	**107.6**	**110.7**	4.2	**1.3**	**2.9**
4Q	107.5	**108.4**	**111.5**	4.5	**0.8**	**2.9**

Consumer Price Index

	Index 1982-1984 = 100 (SAAR)			% Change From Same Quarter **In Prior Year**[2]		
	Actual	**Forecast**[1]		Actual	**Forecast**	
Quarter	2014	2015	2016	2014	2015	2016
1Q	235.4	235.2	**239.9**	1.4	-0.1	**2.0**
2Q	236.8	236.9	**241.3**	2.1	0.0	**1.8**
3Q	237.5	**238.0**	**242.6**	1.8	**0.2**	**1.9**
4Q	237.0	**238.8**	**244.0**	1.2	**0.7**	**2.2**

***See explanatory notes on inside of back cover for details of how this data is compiled.**

BLUE CHIP INTERNATIONAL CONSENSUS FORECASTS

	ANNUAL DATA						END OF YEAR			
	Real Economic Growth % Change GDP		Inflation % Change Consumer Prices		Current Account In Billions Of U.S. Dollars		Exchange Rate [1] Against U.S. $		Interest Rates 3-Month	
CANADA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**1.2**	**2.1**	**1.1**	**2.1**	**-53.4**	**-44.3**	**1.31**	**1.28**	**0.67**	**1.07**
Top 3 Avg.	1.8	2.5	1.4	2.4	-47.3	-35.1	1.37	1.37	0.77	1.25
Bottom 3 Avg.	0.9	1.7	0.8	1.8	-60.1	-59.4	1.23	1.20	0.53	0.81
Last Month Avg.	1.4	2.1	1.1	2.1	-51.6	-42.2	1.28	1.26	0.74	1.45
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.0	2.5	0.9	1.9	-54.6	-39.4	1.33	1.09	0.68	1.21
MEXICO	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**2.3**	**2.9**	**2.9**	**3.5**	**-27.2**	**-25.4**	**16.21**	**15.99**	**3.49**	**4.18**
Top 3 Avg.	2.5	3.4	3.3	3.7	-22.1	-17.5	17.09	17.18	3.70	4.32
Bottom 3 Avg.	2.2	2.5	2.7	3.2	-31.9	-34.0	15.42	15.00	3.29	4.03
Last Month Avg.	2.6	3.2	3.0	3.5	-27.6	-27.7	15.73	15.56	3.59	4.43
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.7	2.1	3.8	4.0	-29.7	-26.5	17.00	13.10	3.34	3.30
JAPAN	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**0.8**	**1.5**	**0.8**	**1.0**	**105.0**	**89.4**	**123.6**	**128.2**	**0.10**	**0.11**
Top 3 Avg.	1.1	1.8	1.1	1.5	133.3	142.8	126.7	132.8	0.14	0.18
Bottom 3 Avg.	0.5	1.1	0.6	0.6	76.8	51.6	121.0	124.5	0.07	0.07
Last Month Avg.	0.9	1.5	0.8	1.1	99.2	85.0	124.9	129.5	0.10	0.12
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.6	-0.1	0.4	2.7	33.6	24.3	119.0	105.0	0.09	0.13
UNITED KINGDOM	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**2.6**	**2.5**	**0.1**	**1.4**	**-139.3**	**-122.4**	**1.52**	**1.52**	**0.58**	**1.19**
Top 3 Avg.	2.7	2.8	0.2	1.7	-124.6	-99.8	1.56	1.58	0.65	1.53
Bottom 3 Avg.	2.4	2.1	0.1	1.2	-151.2	-144.4	1.48	1.48	0.48	0.91
Last Month Avg.	2.5	2.4	0.2	1.5	-139.4	-122.1	1.52	1.52	0.64	1.35
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.7	2.8	2.6	1.5	-119.9	-162.2	1.54	1.63	0.57	0.55
SOUTH KOREA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**2.6**	**3.3**	**0.8**	**1.9**	**101.9**	**94.0**	**1163**	**1157**	**1.63**	**1.99**
Top 3 Avg.	3.2	3.7	1.2	2.4	117.4	109.3	1222	1233	1.69	2.13
Bottom 3 Avg.	2.3	2.8	0.5	1.0	82.4	78.1	1104	1098	1.57	1.85
Last Month Avg.	2.7	3.4	0.8	1.9	100.4	89.4	1134	1133	1.75	2.06
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.9	3.3	1.3	1.3	61.6	84.3	1180	1020	1.57	2.34
GERMANY	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**1.7**	**2.0**	**0.4**	**1.4**	**259.4**	**245.0**	**1.09**	**1.05**	**-0.01**	**0.04**
Top 3 Avg.	1.9	2.3	0.6	1.8	270.8	262.5	1.15	1.09	0.02	0.12
Bottom 3 Avg.	1.5	1.6	0.2	0.9	249.0	225.6	1.03	0.99	-0.04	-0.02
Last Month Avg.	1.7	2.0	0.5	1.6	259.1	248.4	1.06	1.04	0.00	0.05
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	0.2	1.6	1.6	0.8	251.3	287.5	1.14	1.32	-0.03	0.15
TAIWAN	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**2.1**	**3.0**	**-0.2**	**1.3**	**74.2**	**71.0**	**32.23**	**32.42**	**1.15**	**1.52**
Top 3 Avg.	3.1	3.6	0.6	1.8	82.6	78.5	33.60	33.90	1.59	1.81
Bottom 3 Avg.	1.1	2.2	-0.6	0.8	67.0	63.6	31.28	31.22	0.72	1.23
Last Month Avg.	2.7	3.2	0.0	1.5	75.7	70.4	31.62	31.66	1.15	1.53
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.2	3.7	1.0	1.4	49.6	62.0	32.40	29.90	0.94	0.94
NETHERLANDS	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**1.9**	**1.7**	**0.5**	**1.3**	**81.0**	**75.8**	**1.09**	**1.05**	**-0.01**	**0.04**
Top 3 Avg.	2.3	2.1	0.7	1.7	84.8	82.9	1.15	1.09	0.02	0.12
Bottom 3 Avg.	1.5	1.4	0.4	0.9	77.3	69.8	1.03	0.99	-0.04	-0.02
Last Month Avg.	1.9	1.8	0.5	1.3	79.3	76.1	1.06	1.04	0.00	0.05
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	-0.7	0.8	2.6	0.3	73.9	88.9	1.14	1.32	-0.03	0.15

*Best estimates available. **In some cases, actual data for 2014 GDP, consumer prices and current account are not yet available. Where it is unavailable, figures are consensus forecasts from December 10, 2014 Blue Chip Economic Indicators. Figures are currency units per U.S. dollar except for U.K., Australia and the Euro.

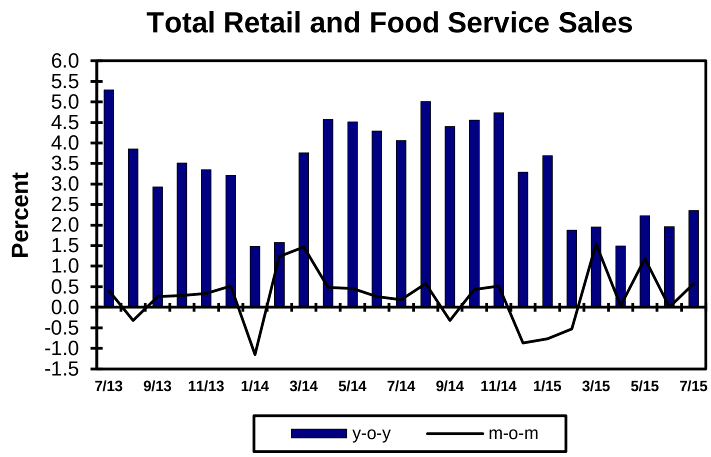
BLUE CHIP INTERNATIONAL CONSENSUS FORECASTS

	ANNUAL DATA						END OF YEAR			
	Real Economic Growth % Change GDP		Inflation % Change Consumer Prices		Current Account In Billions Of U.S. Dollars		Exchange Rate [1] Against U.S. $		Interest Rates 3-Month	
RUSSIA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**-3.7**	**0.4**	**15.2**	**7.5**	**62.1**	**58.9**	**63.1**	**62.8**	**12.82**	**8.80**
Top 3 Avg.	-2.9	1.8	15.9	9.6	87.6	76.6	69.3	68.0	13.45	9.26
Bottom 3 Avg.	-4.4	-1.1	14.5	6.0	37.6	43.3	57.8	58.8	12.12	8.42
Last Month Avg.	-3.5	0.5	14.5	7.4	57.8	60.7	59.9	60.2	12.08	8.60
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.3	0.7	6.8	7.8	34.1	57.4	66.6	36.8	12.60	9.87
FRANCE	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**1.1**	**1.5**	**0.2**	**1.2**	**-21.6**	**-21.4**	**1.09**	**1.05**	**-0.01**	**0.04**
Top 3 Avg.	1.3	1.7	0.4	1.5	-11.2	-9.5	1.15	1.09	0.02	0.12
Bottom 3 Avg.	1.0	1.2	0.1	0.8	-34.0	-34.3	1.03	0.99	-0.04	-0.02
Last Month Avg.	1.2	1.5	0.3	1.2	-21.6	-21.4	1.06	1.04	0.00	0.05
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	0.4	0.4	1.0	0.6	-40.2	-29.9	1.14	1.32	-0.03	0.15
BRAZIL	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**-1.9**	**0.1**	**8.6**	**6.2**	**-72.3**	**-64.8**	**3.51**	**3.50**	**13.83**	**12.67**
Top 3 Avg.	-1.3	1.2	9.2	7.4	-65.1	-55.8	3.87	3.84	13.97	13.70
Bottom 3 Avg.	-2.6	-1.1	7.6	5.2	-77.9	-72.6	3.11	3.21	13.66	11.63
Last Month Avg.	-1.6	0.6	8.5	6.2	-74.4	-67.4	3.37	3.40	13.59	12.44
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.7	0.2	6.2	6.3	-81.2	-91.3	3.70	2.23	14.30	10.80
HONG KONG	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**2.3**	**2.6**	**3.0**	**2.8**	**7.6**	**7.6**	**7.77**	**7.78**	**0.60**	**1.59**
Top 3 Avg.	2.6	3.1	3.5	3.6	10.9	12.3	7.80	7.80	0.81	2.27
Bottom 3 Avg.	1.9	2.1	2.4	1.9	2.9	1.5	7.75	7.75	0.38	1.04
Last Month Avg.	2.2	2.6	3.1	2.9	7.4	7.6	7.77	7.78	0.69	1.76
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.9	2.3	4.3	4.4	7.4	6.0	7.75	7.75	0.41	0.36
INDIA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**7.5**	**7.8**	**5.3**	**5.6**	**-29.5**	**-42.1**	**65.2**	**64.8**	**7.58**	**7.20**
Top 3 Avg.	7.9	8.3	5.9	6.1	-20.5	-30.4	66.8	67.7	7.97	7.64
Bottom 3 Avg.	7.2	7.1	4.9	4.9	-39.3	-50.8	63.2	62.5	7.22	6.78
Last Month Avg.	7.5	7.7	5.4	5.7	-31.4	-41.7	64.5	64.4	7.60	7.26
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	6.4	7.2	10.7	6.7	-32.4	-29.5	66.4	60.5	7.42	8.60
CHINA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**6.8**	**6.6**	**1.5**	**2.1**	**311.8**	**306.6**	**6.44**	**6.52**	**3.34**	**3.33**
Top 3 Avg.	7.0	6.9	1.7	2.8	395.9	403.6	6.61	6.79	3.92	4.02
Bottom 3 Avg.	6.6	6.2	1.3	1.5	223.6	189.1	6.25	6.26	2.76	2.64
Last Month Avg.	6.9	6.6	1.4	2.0	349.3	348.9	6.24	6.22	3.53	3.61
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	7.7	7.4	2.6	2.1	182.8	209.8	6.36	6.14	3.10	4.66
AUSTRALIA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**2.4**	**2.7**	**1.8**	**2.5**	**-52.9**	**-51.7**	**0.72**	**0.72**	**2.21**	**2.46**
Top 3 Avg.	2.7	3.1	2.0	2.8	-36.6	-31.5	0.78	0.76	2.42	2.75
Bottom 3 Avg.	2.1	2.1	1.6	2.2	-75.1	-76.8	0.69	0.68	2.03	2.19
Last Month Avg.	2.5	2.8	1.8	2.6	-48.5	-47.0	0.73	0.73	2.21	2.45
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.1	2.7	2.4	2.5	-48.3	-51.3	0.70	0.93	2.28	2.80
EUROZONE	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
September Consensus	**1.4**	**1.8**	**0.1**	**1.1**	**335.9**	**323.1**	**1.09**	**1.05**	**-0.01**	**0.04**
Top 3 Avg.	1.7	2.0	0.3	1.3	399.2	383.9	1.15	1.09	0.02	0.12
Bottom 3 Avg.	1.3	1.5	-0.1	0.9	277.0	264.5	1.03	0.99	-0.04	-0.02
Last Month Avg.	1.5	1.8	0.2	1.2	332.3	320.6	1.06	1.04	0.00	0.05
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	-0.4	0.9	1.4	0.4	251.3	287.5	1.14	1.32	-0.03	0.15

Contributors to Blue Chip International Survey: IHS Global Insight, US; Barclays, US; Federal Express Corporation, USA; Credit Suisse, US; JP Morgan, US; Economist Intelligence Unit, UK; BMO Capital Markets, Canada; UBS, US; AIG, New York, NY; Oxford Economics, US; Societe Generale, New York, NY; Bank of America-Merrill Lynch, US; Nomura Capital Markets America, US; Morgan Stanley; US; Moody's Capital Markets, US; Eaton, US; Wells Fargo, US; Moody's Analytics, US; Swisse Re, U.S.; Barclays Capital, US; General Motors Corp., US; and Grupo de Economistas y Asociados, Mexico.

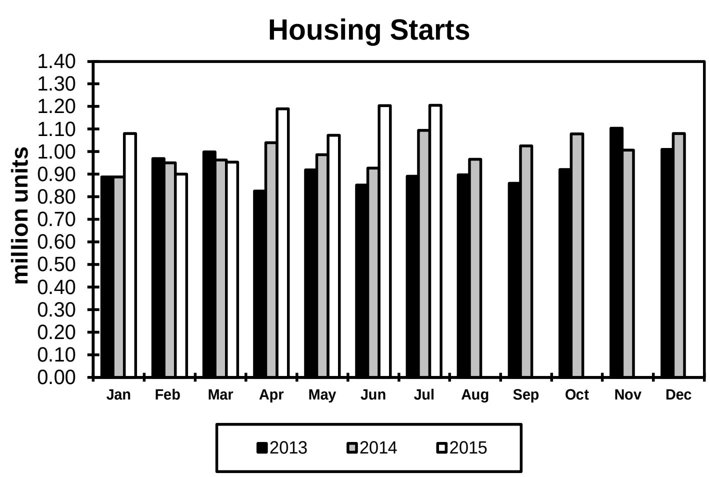
Recent Developments:

Total Retail Sales Registered A Solid Increase In July



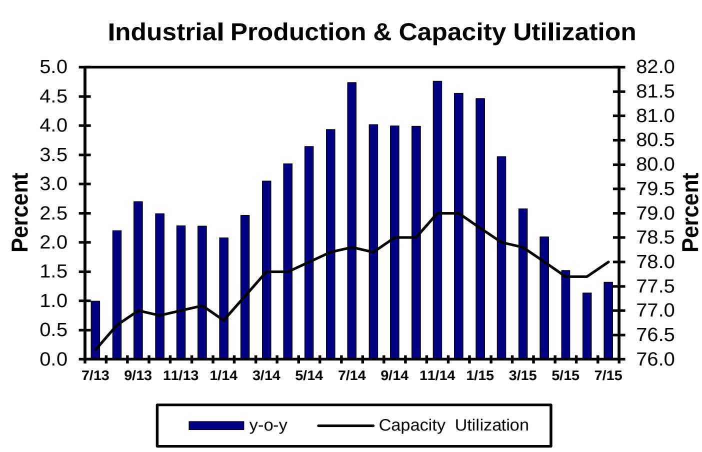
Total retail sales increased an about as expected 0.6% in July, but sales gains in May and June were revised up to 1.2% and 0.0% respectively. The changes left total sales up 2.4% y/y in July. Core retail sales (excludes autos, gasoline and building materials and feed into calculation of non-auto consumer goods consumption) rose 0.3% in July and were up 0.2% in June and 0.8% in May. Core sales were 2.8% higher on a y/y basis in July. July sales excluding autos increased 0.4%, duplicating their June advance. Auto sales jumped 1.4%, a turnaround after the 1.5% decline in June. On a y/y basis, they were up 6.9%. Sales at building material stores rose 0.7% in July after upwardly-revised increases of 0.2% in each of the prior two months. Furniture store sales rose 0.8% and were up 6.1% y/y, while apparel sales increased 0.4% in July and were 3.0% y/y. Sales at gasoline stations rose just 0.4% in July and were down 15.2% y/y, the weakness reflecting lower prices for gas. Sales at general merchandise stores remained soft in July, falling 0.5% and up only 0.3% y/y. Total retail sales in August also likely registered a solid gain, led by unit sales of cars and light trucks that increased 1.4% to the highest annualized rate in any month since July 2005.

Total Housing Starts In July At Highest Annualized Level Since October 2007



Total housing increased 0.2% in July to an annualized rate of 1.206 million units. That followed a revised 12.3% increase in June after 9.9% decline in May. The annualized level of total starts in July stood at the highest level since October 2007. On a y/y basis, total starts were up 10.1% in July. Starts of single-family home rose 12.8% after declines of 0.6% in June and 5.2% in May. They were up 19.0% on a y/y basis. Starts of multi-family homes fell 17.0% in July after a 36.3% surge in June and a 17.6% drop in May. On a y/y, basis they were down 3.2% in July. Total permits fell 16.3% in July to an annualized rate of 1.119 million units, while those for single-family homes falling 1.9%, but permits for multi-family homes plunging 31.8%. On a y/y basis, total permits were up 7.5% in July, single-family starts 6.1% higher and multi-family permits up 9.7%. New home sales rose 5.4% in July to an annualized rate of 507,000. That followed a 7.7% drop in June and a 2.6% increase in May. The median price of a new home sold in July was 2.0% higher a year ago. Existing homes sales increased 2.0% in July to an annualized rate of 5.590 million units. Single-family sales rose 2.7%, while sales of condos/co-ops fell 3.1%.

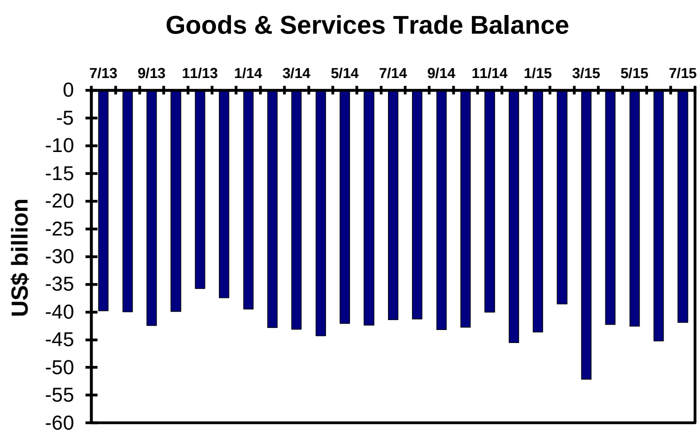
Total Industrial Production Rose More Than Expected In July On Back Of Vehicle Output



Total industrial production increased a larger-than-expected 0.6% in July, the gain driven by a 0.8% jump in manufacturing output. Mining output fell 0.2% in July while utility output slumped 1.0%. The July increase in total production left it up 1.3% y/y. Manufacturing output was up 1.5% y/y in July, mining output was down 2.0% y/y, and utility output 4.6% higher y/y. A 10.6% surge in auto and parts production accounted for the bulk of July's increase in manufacturing output. The jump resulted from a smaller-than-usual decline in production due to summer retooling. Excluding vehicle production, manufacturing output rose just 0.1% in July. The total capacity utilization rate rose to 78.0% in July from 77.7% in June, while the capacity utilization for manufacturing increased to 76.2 from 75.7%. The Institute of Supply Management's index of manufacturing activity slipped from 52.7% in July to 51.1 in August, its lowest level since May 2013. The news orders index fell to 51.7 in august from 56.5 in July, while the production index dropped to 53.6 in August from 56.0 in July. Hurt by weak growth aboard and a strong dollar the export index fell to 46.5 from 48.0.

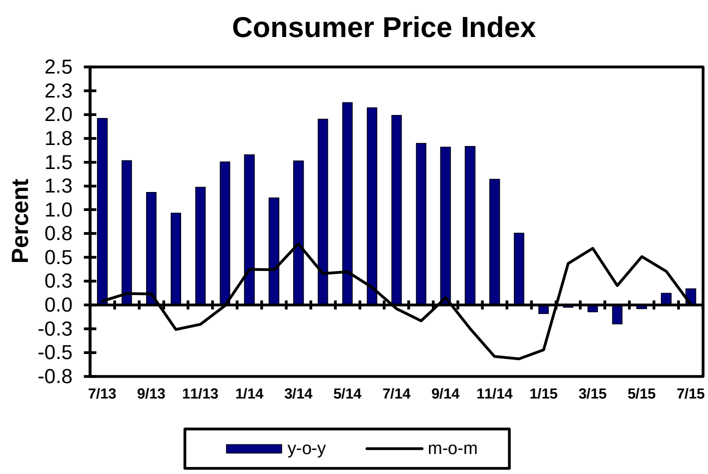
Recent Developments:

Trade Deficit Narrowed In July



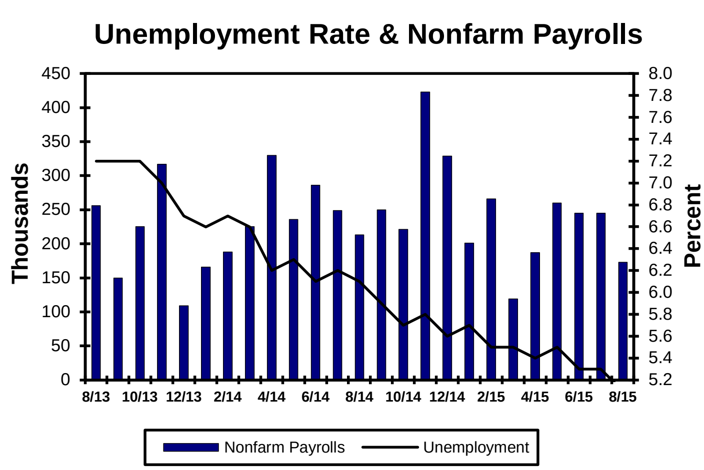
The nominal (current dollar) trade deficit narrowed to $41.9 billion in July from a revised $45.2 billion in June. Nominal exports increased 0.4% in July and were down 4.3% y/y, while nominal imports contracted 1.1% and were down 3.3% y/y. The real (constant dollar) trade deficit narrowed to $56.2 billion in July from $59.0 billion the month before. Real exports increased 0.9% in July but were down 0.6% y/y, while real imports fell by 0.9% in July and were up 4.2% y/y. Real exports of autos were up 4.9% in July, but were down 9.8% y/y. Real exports of capital goods rose 0.3% during the month and were down 3.9% y/y. Real imports of autos were up 1.1% in July, but 7.0% higher y/y, while imports of capital goods increased 0.6% in July and were up 1.8%y/y. Revisions to prior months suggest real net exports contributed 0.1 of a percentage point less to real GDP's growth rate in Q2 than currently assumed by the Bureau of Economic Analysis. If sustained, the July data suggests trade would add several tenths of a percentage point to Q3's rate of GDP growth. The strength of the U.S. dollar and soft economic growth abroad, however, argue otherwise.

Consumer Price Index Up Just 0.1% In July



The Consumer Price Index increased a smaller-than-expected 0.1% in July. That nonetheless left it growing at an annual rate of 3.6% over the last three month. The CPI was up 0.2% on a y/y basis in July versus 0.1% in June. Energy prices rose 0.1% in July, but were still down 14.8% y/y. Gasoline prices rose just 0.9% following a 3.4% rise in June and a 10.4% jump in May. However, they still were down 22.3% on a y/y basis. Food prices increased 0.2 in July and were up just 1.6% y/y. The core CPI (excludes food and energy prices) also rose 0.1% in July, but its y/y change remained at 1.8%. That also matched its annual rate of change over the past three months. Shelter prices rose 0.4% in July and were up 3.1% y/y. Rent of primary residence and owners' equivalent rent both increase 0.3% in July. The former was up 3.6% y/y, while the latter was up 3.0% y/y. Apparel prices rose 0.3% in July but were down 1.6% y/y. Medical care costs just 0.1% in July and were 2.5% y/y. New vehicle prices slipped 0.2% in July and were up only 0.7% y/y. Headline consumer price inflation likely continued to look pretty soft in August, held down by a retreat in gasoline prices. The core CPI in August likely rose 0.1% for a second month.

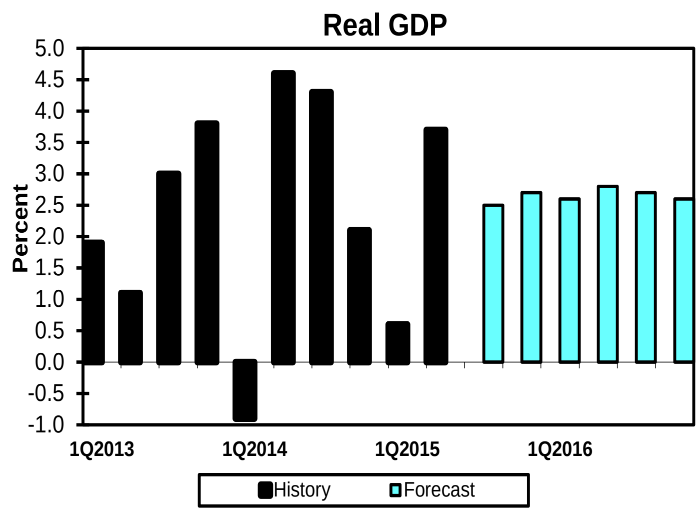
August Nonfarm Payrolls A Bit Softer Than Expected, But Jobless Rate Fell To 5.1%



Total nonfarm payroll growth was a little short of expectations in August, growing by 173,000. However, gains in the prior two months were revised up by a net of 44,000, taking the sting out of the August miss. Moreover, the household survey indicated that the unemployment rate fell 0.2 of a percentage point to 5.1% last month, the lowest since April 2008. Private payroll growth also was short of consensus forecasts, coming in at 140,000 in August, but over the past three months registered healthy average increases of 194,000. Manufacturing payrolls fell by 17,000 while construction payrolls grew by 3,000. Private service-producing company payrolls grew by 164,000. Government payrolls jumped by an unusually large 33,000 last month, likely reflecting the hiring of teachers. The average workweek increased to 34.6 hours in August and average hourly earnings grew by 0.3% and were up 2.2% y/y. Together, the August gain in payrolls and average hourly earnings, coupled with the drop in the jobless rate, surely meets the Fed's criteria of "some further" progress on the labor front as it deliberates raising interest rates for the first time in nine years.

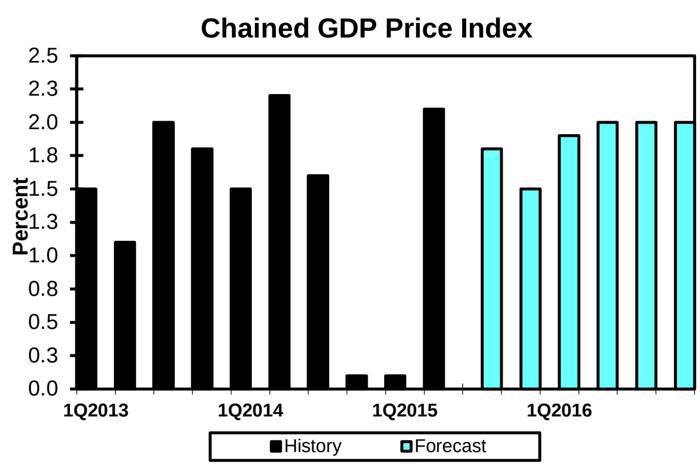
Quarterly U.S. Forecasts:

Real GDP



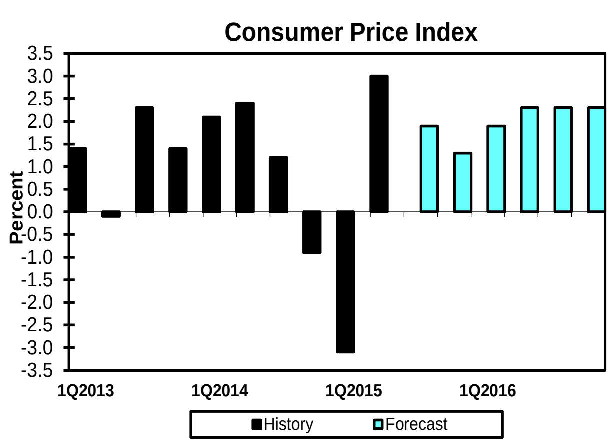
Real GDP grew 3.7% (q/q,saar) in Q2, according to BEA's second estimate. That was a 1.4 percentage points faster than BEA's first estimate. Growth in real personal consumption expenditures (PCE) was revised up by 0.2 of a percentage point to 3.1% (q/q,saar). More impressively, growth in real nonresidential fixed investment was revised up to 3.2% (q/q,saar) versus the prior estimate of a 0.6% contraction. Growth in real residential investment was revised up by 1.2 percentage points to 7.8% (q/q,saar), while government spending and investment now is estimated to have grown 2.6% (q/q,saar) compared to the prior estimate of just 0.8%. Real net exports now are estimated to have added bit more to GDP growth in Q2, while private inventories are estimated to have contributed a little to GDP, rather than subtracting from it. The consensus now forecasts that real GDP will grow 2.5% (q/q,saar) this quarter and 2.7% in Q4. The Q3 figure fell 0.2 of a percentage point over the past month, the Q4 estimate dropped 0.1 of a point. Nonetheless, consensus forecasts of annual and q4/q4 real GDP growth in 2015 rose by 0.2 of a point and 0.3 of a point, to 2.5% and 2.4%, respectively. The increases were due to the large upward revision in Q2 growth. The forecast of annual and q4/q4 growth in 2016 remained at 2.7%.

Chained GDP Price Index



The GDP price index increased at an upwardly revised rate of 2.1% (q/q,saar) in Q2, according to BEA's second estimate. That compares with increases of only 0.1% (q/q,saar) in Q1 2015 and Q4 2014 when plunging oil prices held down inflation. The price index for personal consumption expenditures increased an unrevised 2.2% (q/q,saar) in Q2 versus declines of 1.9% in Q1 and 0.4% in Q4 2014. The price index for consumer goods increased an unchanged 2.5% (q/q,saar) in Q2, while the price index for consumer services increased an unchanged 2.0%. The price index for business fixed investment contracted an upwardly revised 1.0% (q/q,saar) in Q2 following a 0.4% drop in Q1. Softness was widespread, with prices indices for equipment, structures and intellectual property products all suffering contractions. The price index for exports fell an upwardly revised 1.0% (q/q,saar) in Q2, the fourth consecutive quarterly decline. The price index for imports dropped an upwardly revised 4.2% (q/q,saar) in Q2, its fifth straight decline. Consensus forecasts of the annual change in the GDP price index this year and next remained at 1.1% and 1.9%, respectively.

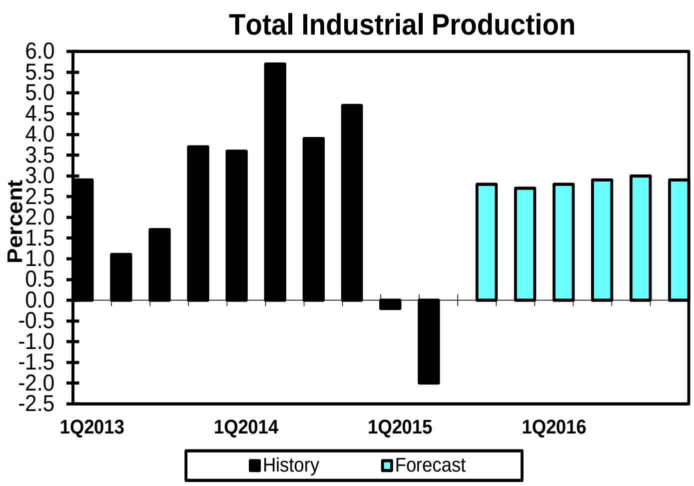
Consumer Price Index



The Consumer Price Index increased an as expected 3.0% (q/q,saar) in Q2 following a 3.1% contraction in Q1 and a 0.9% decline in Q4 2014. The prior weakness was largely the result of sharp declines in energy price since the summer of 2014. The core CPI (excludes food and energy) increased 2.5% (q/q,saar) in Q2 compared with 1.7% in Q1 of this year and 1.5% in Q4 of last year. Over the three months ended in July, the CPI increased at an annual rate of 3.6%, while the core CPI increased at an annual rate of 1.8%. Holding down the y/y increase in the CPI over the past year was a 14.8% y/y contraction in energy prices, exemplified by a 22.3% y/y drop in the price for gasoline. However, energy prices rebounded at an annual rate of 27.2% in the three months ended in July. Food prices rose 1.9% at an annual rate in the three months ended in July but were up just 1.6% y/y. Consensus forecasts of the 2015 and 2016 annual change in the CPI both slipped 0.1 of a percentage point this month to 0.2% and 2.0%, respectively. On a q/q basis, the CPI is forecast to increase 0.7% this year and 2.2% next year.

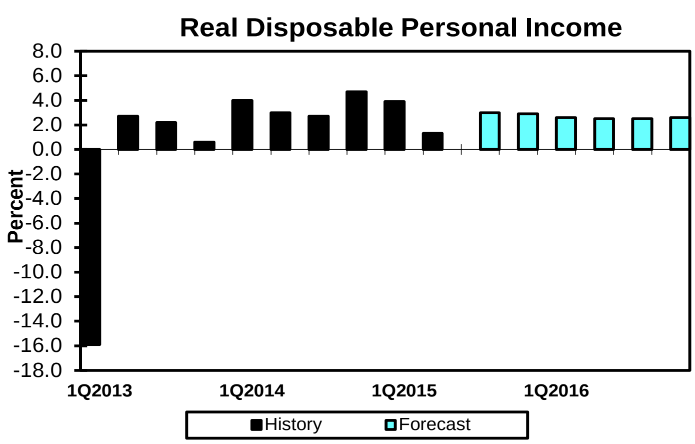
Quarterly U.S. Forecasts:

Industrial Production



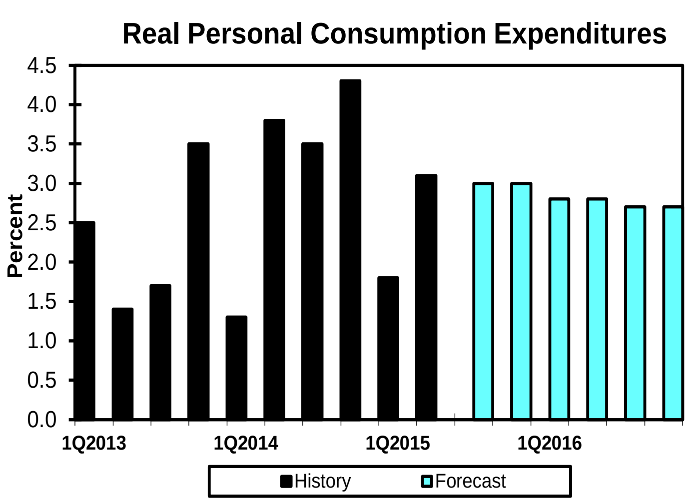
Total industrial production contracted a downwardly revised 2.0% (q/q,saar) in Q2 after declining an upwardly revised 0.2% in Q1. Manufacturing output, however, bucked the trend, growing a downwardly revised 1.2% (q/q,saar) in Q2 versus a 0.7% contraction in Q1 of this year. Holding down the increase in total production in Q2 were sharp contractions in utility and mining output, the latter the result of cutbacks in oil and gas exploration due to the plunge in energy prices. Mining output contracted 11.8% (q/q,saar) in Q2 after falling 3.6% in Q1, while utility output declined 11.0% in Q2 following growth of 8.2% in the prior quarter. Powering the Q2 increase in manufacturing output, motor vehicle and parts production jumped 14.2% (q/q,saar) last quarter versus growth of only 1.5% in the prior quarter. In contrast, production of business equipment grew only 1.8% (q/q,saar) after falling 3.2% in Q1. The consensus predicts total industrial production will rebound in the second half of this year, registering annual growth of 1.8% but a q4/q4 increase of only 0.8%. It is predicted to grow 2.6% on an annual basis in 2016 and 2.9% q4/q4, both estimates 0.1 of a percentage point less than forecast a month ago.

Real Disposable Personal Income



Real disposable personal income (DPI) increased a downwardly revised 1.3% (q/q,saar) in Q2, according to BEA's second estimate. That followed upwardly revised growth of 3.9% in Q1 of this year. Real DPI minus transfer payments grew 1.5% (q/q,saar) in Q2. Capping growth last month in real DPI was a 2.2% (q/q,saar) increase in the price index for personal consumption expenditures. That compares with a contraction in the PCE price index of 1.9% in Q1 of this year that largely resulted from plunging energy prices. Nominal (current dollar) DPI actually increased at a faster 3.5% (q/q,saar) clip in Q2 than the 1.9% pace registered in Q1. Nominal wages and salaries increased an upwardly revised 2.5% (q/q,saar) in Q2, just slightly slower than its 2.6% increase in Q1. Rental income surged 11.9% (q/q,saar) versus 5.5% in Q1, while interest income jumped 9.8% compared to a 2.2% decline in Q1. Dividend income, however, rose just 0.8% (q/q,saar) in Q2 versus a 11.0% jump in Q1. The consensus this month continued to predicts annual real DPI growth of 3.2% in 2015 and 2.6% in 2016.

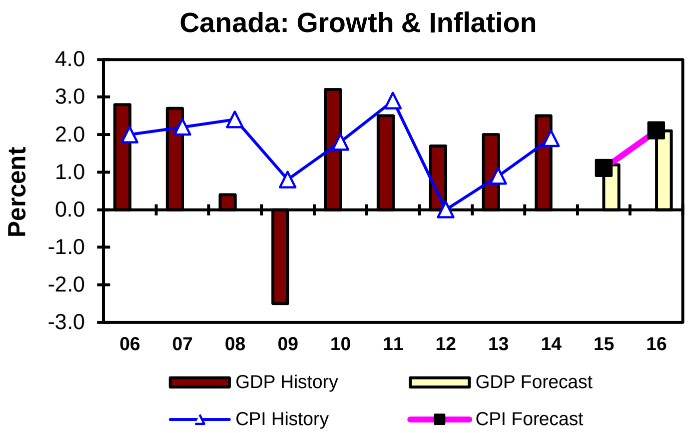
Real Personal Consumption Expenditures



Real personal consumption expenditures (PCE) increased an upwardly revised 3.1% (q/q,saar) in Q2, according to BEA's second estimate. That was 0.2 of a percentage point better than the BEA's initial estimate and compares with Q1's growth rate of 1.8% (q/q,saar). Consumer spending on goods in Q2 increased an upwardly revised 5.5% (q/q,saar), the best advance since Q2 2014. The increase was driven by growth of 8.2% (q/q,saar) in durable goods as purchases of cars and trucks accelerated. Consumer spending on nondurable goods grew an upwardly revised 4.1% (q/q,saar) in Q2, while spending on services expanded at a trend-like rate of 2.0%, 0.1 of a percentage point slower than BEA's initial estimate and its rate of growth in Q1 of this year. Solid vehicle sales in July and August suggest that real PCE growth likely remained healthy in the current quarter. The consensus forecast of annual growth in real PCE during 2015 remained at 3.0% for a third, consecutive month. That would mark the best annual performance since 2006. The consensus forecast of real PCE's annual increase in 2016 was unchanged this month to 2.9%.

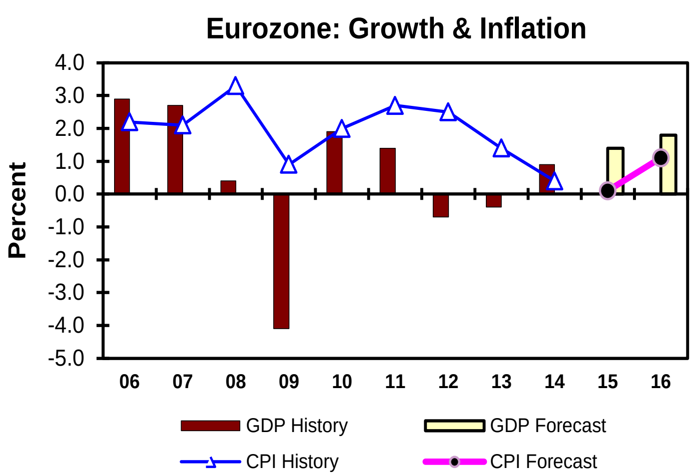
International Forecasts:

Canada



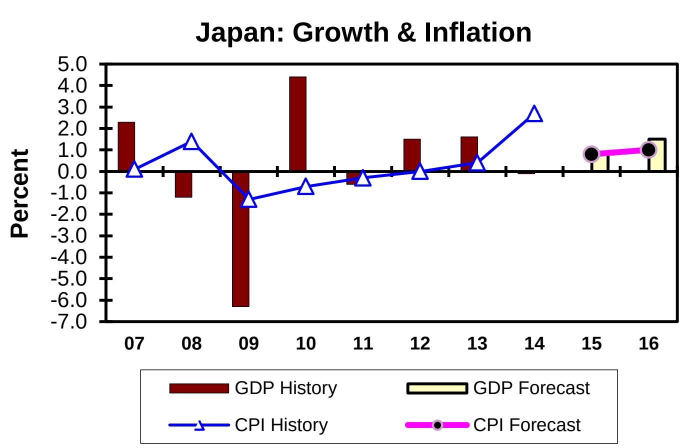
As widely anticipated, real GDP contracted for a second consecutive quarter in Q2. While the decline was a less-than-expected 0.5% (q/q,saar), Q1's contraction was revised to 0.8% versus the 0.6% originally estimated. The Q2 contraction occurred despite a 0.5% increase in June real GDP, breaking a five-month stretch of negative readings, and setting the stage for a Q3 revival in growth, according to optimists. They note that consumer spending and job growth actually grew during the first half of this year, hardly indicative of broad-based softening in the economy. Instead, a huge 12.0% (q/q,saar) contraction in business investment that came on top of a 17.7% plunge in Q1 accounts for much of the weakness in GDP. On top of that, a swing in inventories sliced about 1.0 percentage point from GDP's growth rate in Q2. Pessimists, however, warn that continued weakness in commodity exports, overly indebted households, and softening residential investment continue to pose risks to the outlook. The consensus forecast of annual real GDP growth in 2015 fell to 1.2% this month, while the forecast of growth in 2016 remained at 2.1%.

Eurozone



Real GDP in the Eurozone grew a less-than-expected 1.3% (q/q,saar) in Q2, the increase lifting the y/y growth rate to 1.2% from 1.0% in Q1. Growth in the currency zone's three largest members was softer than expected. German real GDP grew 1.8% (q/q,saar) in Q2 and up 1.6% y/y, Italy's 0.7% and 0.5% higher y/y, but in France it was unchanged last quarter and up 1.0% y/y. Spain – where real structural reforms were enacted -- remained the standout, growing 4.1% (q/q,saar) in Q2 and up 3.1% y/y. Performance in Q2 was worst in Finland and Austria, where Q2 real GDP contracted 1.6% and 2.9%, respectively. On a y/y basis real GDP was down 0.9% in Finland and up just 0.4% in Austria. Inflation remains extraordinarily soft in the Eurozone. Harmonized consumer price inflation was up only 0.2% on a y/y basis in August, while core inflation was only slightly that. Sluggish growth and inflation figures for Q2 recently prompted staff economists at the European Central Bank to cut their forecasts of real GDP growth and inflation for this year and next. Due to downgrading of the outlook, the ECB had signaled that it stands ready to expand its massive bond-buying program. The consensus forecast of annual real GDP growth in 2015 slipped back to 1.4% this month, but the 2016 forecast stayed at 1.8%.

Japan



Real GDP contracted 1.6% (q/q,saar) in Q2. However, the decline followed upwardly revised growth of 4.5% (q/q,saar) in Q1, leaving the economy at least temporarily growing above potential during the first half of the year. Softness in Q2 was accounted for by a 3.0% (q/q,saar) decline in private consumption, a 0.3% drop in spending on plant and equipment, and a widening of the trade deficit. While industrial production unexpectedly fell in July, the August manufacturing PMI rose to 51.9, its highest level in seven months. Moreover, the August services PMI rose to 53.7, its highest level in almost two years. Also encouraging, July retail sales beat expectations, rising 1.6% y/y versus the 1.1% expected. Household spending, on the other hand, contracted 0.2% y/y versus expectations for a 1.3% rise. Hopes for stronger GDP growth in the second half of this year has been tempered by China's devaluation of the yuan and recent stock markets losses. Inflation remains nonexistent with the core Consumer Price Index unchanged y/y in July. The consensus forecasts of annual real GDP growth this year fell back to 0.8% this month, but the forecast of growth in 2016 remained at 1.5%.

Databank:

2015 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	-0.8	-0.5	1.5	0.0	1.2	0.0	0.6					
Auto & Light Truck Sales (b)	16.63	16.32	17.06	16.70	17.63	16.95	17.47	17.72				
Personal Income (a, current $)	0.2	0.3	0.0	0.4	0.4	0.4	0.4					
Personal Consumption (a, current $)	-0.4	0.2	0.5	0.3	0.8	0.3	0.3					
Consumer Credit (e)	3.6	5.5	7.6	7.6	5.9	7.3						
Consumer Sentiment (U. of Mich.)	98.1	95.4	93.0	95.9	90.7	96.1	93.1	91.9				
Household Employment (c)	759	96	34	192	272	-56	101	196				
Non-farm Payroll Employment (c)	201	266	119	187	260	245	245	175				
Unemployment Rate (%)	5.7	5.5	5.5	5.4	5.5	5.3	5.3	5.1				
Average Hourly Earnings (All, cur. $)	24.76	24.78	24.85	24.89	24.95	24.95	25.01	25.09				
Average Workweek (All, hrs.)	34.6	34.6	34.5	34.5	34.5	34.5	34.5	34.6				
Industrial Production (d)	4.5	3.5	2.6	2.1	1.5	1.1	1.3					
Capacity Utilization (%)	78.7	78.4	78.3	78.0	77.7	77.7	78.0					
ISM Manufacturing Index (g)	53.5	52.9	51.5	51.5	52.8	53.5	52.7	51.1				
ISM Non-Manufacturing Index (g)	56.7	56.9	56.5	57.8	55.7	56.0	60.3	59.0				
Housing Starts (b)	1.080	0.900	0.954	1.190	1.072	1.204	1.206					
Housing Permits (b)	1.059	1.098	1.038	1.140	1.250	1.337	1.119					
New Home Sales (1-family, c)	521	545	485	508	521	481	507					
Construction Expenditures (a)	-1.2	0.6	1.3	3.8	2.3	0.7	0.7					
Consumer Price Index (nsa., d)	-0.1	0.0	-0.1	-0.2	0.0	0.1	0.2					
CPI ex. Food and Energy (nsa., d)	1.6	1.7	1.8	1.8	1.7	1.8	1.8					
Producer Price Index (nsa., d)	0.0	-0.5	-0.9	-1.3	-1.1	-0.7	-0.8					
Durable Goods Orders (a)	1.9	-3.5	5.1	-1.7	-2.3	4.1	2.0					
Leading Economic Indicators (g)	0.2	-0.2	0.4	0.6	0.6	0.6	-0.2					
Balance of Trade & Services (f)	-42.4	-37.2	-50.6	-40.7	-42.5	-45.2	41.9					
Federal Funds Rate (%)	0.11	0.11	0.11	0.12	0.12	0.13	0.13					
3-Mo. Treasury Bill Rate (%)	0.03	0.02	0.03	0.02	0.02	0.02	0.03					
10-Year Treasury Note Yield (%)	1.88	1.98	2.04	1.94	2.20	2.36	2.32					

2014 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	-1.2	1.2	1.5	0.5	0.5	0.3	0.2	0.6	-0.3	0.4	0.5	-0.9
Auto & Light Truck Sales (b)	15.29	15.51	16.46	16.21	16.64	16.74	16.45	17.22	16.42	16.46	17.02	16.80
Personal Income (a, current $)	0.5	0.6	0.6	0.2	0.3	0.4	0.3	0.4	0.2	0.4	0.5	0.3
Personal Consumption (a, current $)	-0.2	0.4	0.8	0.2	0.3	0.5	0.2	0.6	0.2	0.4	0.3	-0.1
Consumer Credit (e)	5.2	5.9	7.5	9.5	7.3	7.1	8.5	5.0	6.2	5.8	5.3	6.7
Consumer Sentiment (U. of Mich.)	81.2	81.6	80.0	84.1	81.9	82.5	81.8	82.5	84.6	86.9	88.8	93.6
Household Employment (c)	535	95	495	-72	144	379	154	50	156	653	71	111
Non-Farm Payroll Employment (c)	166	188	225	330	236	286	249	213	250	221	423	329
Unemployment Rate (%)	6.6	6.7	6.6	6.2	6.3	6.1	6.2	6.1	5.9	5.7	5.8	5.6
Average Hourly Earnings (All, cur. $)	24.22	24.30	24.34	24.34	24.4	24.46	24.47	24.55	24.55	24.59	24.68	24.62
Average Workweek (All, hrs.)	34.4	34.4	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.6	34.6	34.6
Industrial Production (d)	2.1	2.5	3.1	3.3	3.6	3.9	4.7	4.0	4.0	4.0	4.8	4.6
Capacity Utilization (%)	76.8	77.3	77.8	77.8	78.0	78.2	78.3	78.2	785	78.5	79.0	79.0
ISM Manufacturing Index (g)	51.8	54.3	54.4	55.3	55.6	55.7	56.4	58.1	56.1	57.9	57.6	55.1
ISM Non-Manufacturing Index (g)	54.3	52.5	53.7	55.3	56.1	56.3	57.9	58.6	58.1	56.9	58.8	56.5
Housing Starts (b)	0.888	0.951	0.963	1.039	0.986	0.927	1.095	0.966	1.026	1.079	1.007	1.080
Housing Permits (b)	1.002	1.030	1.061	1.074	1.017	1.033	1.041	1.040	1.053	1.120	1.079	1.077
New Home Sales (1-family, c)	446	417	410	410	457	408	403	454	459	472	449	495
Construction Expenditures (a)	-0.4	0.4	0.0	1.4	1.3	-1.6	0.3	0.1	0.6	1.4	-0.6	0.8
Consumer Price Index (sa, d)	1.6	1.1	1.5	2.0	2.1	2.1	2.0	1.7	1.7	1.7	1.3	0.8
CPI ex. Food and Energy (sa, d)	1.6	1.6	1.7	1.8	2.0	1.9	1.9	1.7	1.7	1.8	1.7	1.6
Producer Price Index (nsa., d)	1.3	1.2	1.6	1.8	2.1	1.8	1.9	1.9	1.6	1.5	1.3	0.9
Durable Goods Orders (a)	-1.4	2.6	3.7	0.9	-0.9	2.7	22.5	-18.3	-0.7	0.3	-2.2	-3.7
Leading Economic Indicators (g)	-0.2	0.6	1.0	0.3	0.6	0.6	1.0	0.1	0.6	0.6	0.3	0.5
Balance of Trade & Services (f)	-39.5	-42.8	-43.1	-44.3	-42.1	-42.4	-41.4	-41.3	-43.2	-42.8	-40.0	-45.6
Federal Funds Rate (%)	0.07	0.07	0.08	0.09	0.09	0.10	0.09	0.09	0.09	0.09	0.09	0.12
3-Mo. Treasury Bill Rate (%)	0.04	0.05	0.05	0.03	0.03	0.04	0.03	0.03	0.02	0.02	0.02	0.03
10-Year Treasury Note Yield (%)	2.86	2.71	2.72	2.71	2.56	2.60	2.54	2.42	2.53	2.30	2.33	2.21

(a) month-over-month % change; (b) millions of units, saar; (c) thousands of units, saar; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Special Questions:

1. At which upcoming meeting do you think the FOMC will FIRST HIKE its target for the federal funds rate?

(Percent of those responding)

Sep.16-17 2015	Oct. 27-28 2015	Dec. 15-16 2015	Jan. 26-27 2016	Mar. 15-16 2016	Later
57.7%	9.6%	30.8%	0.0%	1.9%	0.0%

2. The mid-point of the FOMC's current federal funds rate target range of 0%-0.25% is 0.125%. The median expectations of FOMC members from the June FOMC meeting put the fed funds rate at 0.625% at the end of 2015 and 1.675% at the end of 2016. What do you think will be the mid-point of the FOMC's fed funds rate target range at the end of 2015 and 2016?

Mid-point of federal funds rate target range at end of:

	2015	2016
Consensus	**0.460%**	**1.540%**
Top 10 Average	0.629%	2.086%
Bottom 10 Average	0.350%	1.088%

3. What will be the average monthly change in total nonfarm payroll employment during the last six months of 2015 and all 12 months of 2016?

Average monthly change in Total Nonfarm Payrolls during

	Second half of 2015	All of 2016
Consensus	**210.5 thousand**	**195.9 thousand**
Top 10 Average	237.1 thousand	241.6 thousand
Bottom 10 Average	137.7 thousand	142.0 thousand

4. After increasing 13.5% in 2012 and 9.5% in 2013, year-to-year growth in real residential investment slowed to just 1.8% in 2014. In the first two quarters of this year, however, it grew 10.1% (q/q,saar) Q1 and 7.8% in Q2. What is your forecast of the y/y percent change in real residential investment in 2015 and 2016?

Y/Y percent change in real residential investment in:

	2015	2016
Consensus	**8.6%**	**8.8%**
Top 10 Average	10.3%	13.0%
Bottom 10 Average	7.5%	5.3%

5. The per barrel price of West Texas Intermediate crude oil has dropped back below $50. What will be the per barrel price at the end of 2015 and 2016?

Price of West Texas Intermediate Crude:

	End of 2015	End of 2016
Consensus	**$48.80 per barrel**	**$58.30 per barrel**
Top 10 Average	$57.20 per barrel	$68.50 per barrel
Bottom 10 Average	$41.30 per barrel	$49.2 per barrel

6. Commodity prices (as measured by the Reuters/Jefferies Commodity Research Bureau Index) have fallen sharply since 2011. There is considerable debate about how of the decline results from decreased demand or increased supply. Please assign what you think are the respective contributions made by decreased demand and increased supply on the fall in commodity prices.

(Percentage contribution made to fall in commodity prices)

	Decreased Demand	Increased Supply
Consensus	**49.6%**	**52.2%**
Top 10 Average	76.0%	77.5%
Bottom 10 Average	25.0%	26.0%

7. The 12-month percent change in the personal consumption expenditures price index excluding food and energy prices (core PCE price index) was 1.2% in July of this year. What will be the December-over-December percent change in the core PCE price index in 2015 and 2016?

Core PCE price index
December-over-December, percent change:

	2015	2016
Consensus	**1.4%**	**1.8%**
Top 10 Average	1.7%	2.2%
Bottom 10 Average	0.9%	1.5%

A Sampling of Views On The Economy Excerpted From Recent Reports Issued By Our Blue Chip Panel Members Or Others

Viewpoints:

Down To 5.1%

Payroll employment increased 177,000 in August with a net 44,000 upward revision to figures for prior months, and the unemployment rate declined 0.2%-pt. to 5.1%.

The household survey sends a simple and strong message about diminished labor market slack. The unemployment rate has reached the FOMC's latest central tendency estimate of NAIRU, 5.1%, and it is very close to our 5.0% estimate. The jobless rate has declined a full percentage point over the past year, and is a half percentage point below its 1Q15 average. Simple extrapolation of recent trends would forecast an unemployment rate below 4.5% in mid-2016. The broader U-6 measure of unemployment shows more slack, but U-6 has been coming down by a faster 1.7%-pts in the past year.

The message from the payroll survey is a bit more ambiguous. The headline figures show a noticeable slowing in job growth, and especially private job growth, in August. But we would view the current trend in job growth as closer to the 221,000 3-month average than the smaller 173,000 August gain. The well-advertised tendency for preliminary August job figures to be revised up is one obvious reason to discount the latest figure. In addition, details of the August report do not look consistent with a shift toward weaker hiring. The average workweek usually declines when labor demand is softening, but the average workweek edged up in August to match its high for the expansion. Temp hiring usually leads a sustained slowdown in overall hiring. But the 11,000 increase in temp hiring in August was above the average for the year to date.

Other incoming data over the past week including surprisingly strong August auto sales are consistent with our forecast that real final sales will increase a solid 3.0% (saar) this quarter, even as a sizable inventory correction holds real GDP growth to 2.0%.

The outcome of the September 17 FOMC meeting is still a close call, but we now think that the Committee will raise the target fed funds rate by 25 basis points. Recent Fed communications indicate that they think inflation will move up to the 2% target if the economy delivers to a forecast of diminishing labor market slack and moderate economic growth. Recent economic data have supported this view. The counter-argument is that stocks are down and financial markets are jittery. High-frequency indicators of the economy such as auto sales, weekly confidence, and initial jobless claims suggest that financial market developments have had little effect on the economy so far. But financial market developments in the days to come could have some bearing on the FOMC decision.

Our forecast of 2.0% real GDP growth this quarter seems to be tracking, and so does the expected composition. We expect real domestic final sales to increase 3.0% (saar) this quarter with help from lower energy prices and lower interest rates. And the latest news on domestic spending has generally been on the high side of our expectations. August sales of new cars and light trucks surged to a new high for the expansion despite the stock market decline toward the ends of the month, which might have been expected to dissuade buyers. July construction spending increased another 0.7% (samr), leaving the 3-month run rate at 15.7% (ar). And the July factory report confirmed the June-July upturn in core capital goods orders and shipments first reported in the durables report.

The trade-weighted dollar is 15% above year-ago levels and real GDP growth for US trading partners has been unusually weak. As a result, real exports of goods and services declined slightly over the first half of the year, and merchandise export volumes were down 3.5% (saar) in the three months through July. The August ISM manufacturing survey's measure of new export orders hit its lowest level in more than three years.

The large build in inventories through the first half points to a correction through 2H15 that will depress inventory accumulation and probably imports. Our forecast looks for inventories to be a 1.0%-pt drag on real GDP growth this quarter.

While we discount the slowdown in overall job growth, special weakness in manufacturing looks consistent with the expected inventory correction and export weakness this quarter. Manufacturing jobs declined 17,000 and hours-worked by production workers declined 0.4% (samr). This result, along with the scheduled decline in auto output, points to a weak month for factory IP.

Hours worked increased 0.4% (samr) in August and hourly earnings rose 0.3%. The payroll proxy for labor income is up 0.7% samr in August and up 5.2% (saar) so far in 3Q15, a support for consumer spending.

Growth of hourly earnings stable around 2%: Hourly earnings increased 0.3% (samr) and 2.2% (y/y) for all workers and increased 0.2% and 1.9% (y/y) for production and nonsupervisory workers in August. The annual increase for all workers is the same as in August 2014, and the annual increase for production and nonsupervisory workers is lower.

The rapid decline in the unemployment rate, alongside solid but unexciting job growth, highlights the continued slow growth of the labor supply. Labor force growth is only 0.5% over the past year and an annual average of 0.4% over the past three years, down from growth averaging over 1% through much of the previous expansion.

Since last autumn, construction activity has accelerated sharply, with total nominal construction spending now up 13.7%oya and up nearly 20% (saar) over the last six months. The latest July results show a 0.7% (samr) increase in spending with upward revisions to prior months. The latest 3-month run rate for growth of construction spending is a 15.7% (saar) with each of the major components (private residential, private nonresidential, and public) posting double-digit growth.

The trade deficit widened enormously in 1Q15 as exports slumped while imports continued to advance. At the time it appeared that this divergence might have been the result of differences in timing of effects of the West Coast port strikes. But the divergence persists. The July level of merchandise export volumes is 3.4% (saar) below the 4Q14 average while import volumes are 4.3% (saar) above their 4Q14 average. July figures continue to show exports struggling. Merchandise export volumes rose 0.9% (samr) in July, leaving the 3-month run rate down at a 3.5% annual rate. And the July result was boosted by a 4.9% (samr) bounce in export volumes for autos and parts, associated with a one-time July surge in auto production that will likely be largely reversed by September. Trade flows are volatile from month to month and even quarter to quarter. But official data show the recent trade deterioration concentrated in 1Q15. Based on July results, net exports look neutral for real GDP growth this quarter.

Robert E. Mellman, JPMorgan Chase, New York, NY

Calendar Of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
7 **Labor Day** **U.S. Markets Closed**	**8** Consumer Credit (Jul) NFIB Survey (Aug)	**9** JOLTS (Jul) Quarterly Services Survey (Q2) EIA Crude Oil Stocks Mortgage Applications	**10** Wholesale Trade (Jul) Import Prices (Aug) Weekly Jobless Claims Weekly Money Supply	**11** Producer Price Index (Aug) Consumer Sentiment (Preliminary, Sep, Univ. of Michigan)
14	**15** Retail Sales (Aug) Industrial Production (Aug) Empire State Survey (Sep) Business Inventories (Jul)	**16** **FOMC Meeting** Consumer Price Index (Aug) NAHB Survey (Sep) TIC Data (Jul) EIA Crude Oil Stocks Mortgage Applications	**17** **FOMC Meeting** **Statement (2:00 pm)** **Press Conference (2:30 pm)** Philadelphia Fed Survey (Sep) Housing Starts (Aug) Current Account Q2) Weekly Jobless Claims Weekly Money Supply	**18**
21 Existing Home Sales (Aug)	**22** Richmond Fed Survey (Sep) FHFA Home Price Survey (Jul)	**23** Markit Maufacturing PMI (Sep, Flash) EIA Crude Oil Stocks Mortgage Applications	**24** Kansas City Fed Survey (Sep) New Home Sales (Aug) Durable Goods (Aug) Weekly Jobless Claims Weekly Money Supply	**25** Real GDP (Q2, Third Estimate) Markit Services PMI (Sep, Flash) Consumer Sentiment (Sep, Final, Univ. of Michigan)
28 Personal Income and Consumption (Aug) Pending Home Sales (Aug) Dallas Fed Survey (Sep)	**29** S&P/Case-Shiller Home Price Index (Jul) Consumer Confidence (Sep, Conference Board)	**30** ADP Employment (Sep) Chicago PMI (Sep) EIA Crude Oil Stocks Mortgage Applications	**October 1** Markit Manufacturing PMI (Sep, Final) ISM Manufacturing (Sep) Vehicle Sales (Sep) Construction Spending (Aug) Weekly Jobless Claims Weekly Money Supply	**2** Employment (Sep) Factory Orders (Aug)
5 Markit Services PMI (Sep, Final) ISM Non-Manufacturing PMI (Sep)	**6** International Trade (Aug)	**7** Consumer Credit (Aug) EIA Crude Oil Stocks Mortgage Applications	**8** **FOMC Minutes** Weekly Jobless Claims Weekly Money Supply	**9** Import Prices (Sep) Wholesale Trade (Aug)
12 **Columbus Day** **U.S. Bond Market Closed**	**13** NFIB Survey (Sep) Federal Budget (FY15)	**14** Retail Sales (Sep) Producer Price Index (Sep) Business Inventories (Aug) Beige Book EIA Crude Oil Stocks Mortgage Applications	**15** Consumer Price Index (Sep) Empire State Survey (Oct) Philadelphia Fed Survey (Oct) Weekly Jobless Claims Weekly Money Supply	**16** Industrial Production (Sep) Consumer Sentiment (Oct, Preliminary, Univ. of Michigan) JOLTS (Aug) TIC Data (Aug)

EXPLANATORY NOTES

For 39 years, ***Blue Chip Economic Indicators'***® monthly survey of leading business economists has provided private and public sector decision-makers timely forecasts of U.S. economic growth, inflation and a host of other critical indicators of business activity. The newsletter utilizes a standardized format that provides a fast read on the prevailing economic outlook. The survey is conducted over two days, typically beginning on the first or second business day of each month. Forecasts of U.S. economic activity are collected from more than 50 leading business economists each month. The newsletter is generally finished on the third day following completion of the survey and delivered to subscribers via e-mail or first class mail.

The hallmark of ***Blue Chip Economic Indicator***® is its *consensus forecasts*. Numerous studies have shown that by averaging the opinions of many experts, the resulting consensus forecasts tend to be more accurate over time than those of any single forecaster.

Annual Forecasts On pages 2 and 3 of the newsletter are individual and consensus forecasts of U.S. economic performance for this year and next. The names of the institutions that contribute forecasts to these pages are listed on the left of the page. They are ranked from top to bottom based on how fast they expect the U.S. economy to expand in the current year. Some of these institutions have one or more asterisks (*) after their names, denoting how many times they have won the annual *Lawrence R. Klein Award for Blue Chip Forecast Accuracy*.

Across the top of pages 2 and 3 is a list of the variables for which the individual cooperators have provided forecasts. Definitions and organizations that issue estimates for these variables are found at the bottom of page 3. For columns 1-9, the forecasts are for the year-over-year percent change in each variable. Columns 10-12 represent average percentage levels of the year in question. Column 15 is an inflation-adjusted dollar level, measured in billions of chained 2009 dollars. High and low forecasts from the panel members for each variable are denoted with an "H" or "L".

Immediately below the forecasts of the individual contributors are this month's consensus forecasts. The consensus is derived by averaging our panel members' forecasts for each variable. Below the consensus forecasts are averages of this month's ten highest and ten lowest forecasts for each variable. Below them are last month's consensus forecasts. To put the forecasts in context, we include four years of historical data for each variable at the bottom of page 2. Please note that these figures can change due to government revisions of previously released estimates. Below the historical data are the number of forecasts changed from a month ago for each variable, the median forecast for each variable and a diffusion index. The diffusion index serves as a leading indicator of future changes in the consensus forecast. A reading above 50% hints of future increases in the consensus; a reading below 50% hints of future declines. The diffusion index is calculated by adding to the number of forecasters who raised their forecasts for a particular variable this month, half the number of those who left their forecasts unchanged, then dividing the sum by the total number of those contributing forecasts.

Historical Annual Consensus Forecasts Page 4 contains the forecasts from previous issues for the current and subsequent year so that subscribers can see how the outlook has changed over time. Each issue also includes graphs and analysis focusing on noteworthy changes and trends in the consensus outlook.

Quarterly Forecasts Page 5 contains quarterly historical data and consensus forecasts of the U.S. economy's performance. For columns 1-7, the forecasts are for the quarter-over-quarter, seasonally-adjusted, annualized percent change in each variable. Columns 8-10 represent average percentage levels for the quarter in question. Columns 11 and 12 represent seasonally-adjusted, annualized levels for the quarter, measured in billions of inflation-adjusted dollars. As is the case on pages 2-3, the consensus quarterly forecasts on the top half of page 5 are simple averages of our contributors' forecasts. The high-10 and low-10 forecasts are averages of the 10 highest and 10 lowest forecasts for each variable. At the bottom of page 5 are additional quarterly consensus forecasts for Real GDP, GDP Price Index, Industrial Production and Consumer Price Index. These figures are derived by taking the annualized quarterly consensus forecasts found on the top of page 5 and computing a quarterly dollar value for Real GDP, and average quarterly index levels for the GDP Price Index, Industrial Production and the Consumer Price Index. We then compute a year-over-year percent change between the relevant quarter and the corresponding quarter of the previous year.

International Forecasts Pages 6-7 contain historical data and consensus forecasts of five key economic variables for 15 of the U.S.'s largest trading partners. A list of the institutions contributing forecasts to these pages can be found at the bottom of page 7. Columns 1 and 2 are forecasts of the year-over-year percent change in inflation-adjusted economic growth and consumer price inflation for this year and next. Column 3 is each nation's estimated current account surplus or deficit, reported in billions of current U.S. dollars. Column 4 is the estimated value of each nation's currency versus the U.S. dollar at the end of this year and next. Column 5 is the estimated level of interest rates on 3-month interest rates in each nation at the end of this year and next. Immediately below this month's consensus and the highest and lowest estimates for each variable are last month's forecasts and a limited amount of historical data. The historical data may change from month-to-month due to government revisions.

Special Questions On page 14, we report on panel members' answers to our special questions. Individuals' responses to the special questions are never displayed, only consensus, top-10 and bottom-10 results. *In March and October, we publish our twice-a-year, long-range survey results*. In addition to our usual forecasts for this year and next, the long-range survey results provide subscribers with consensus forecasts of all the variables found on pages 2 and 3 for the each of the following five years, plus an average for the five-year period after that.

Blue Chip Econometric Detail® With the March, June, September and December issues, subscribers also receive a four-page quarterly supplement entitled *Blue Chip Econometric Detail*®. The supplement contains forecasts of an expanded list of economic and financial variables that are derived from the consensus forecasts found in *Blue Chip Economic Indicators*®. Macroeconomic Advisers, LLC of St. Louis, Missouri produces this forecast detail based on a simulation of its econometric model of the U.S. economy.

*Should you have questions about the contents, or methods used to produce **Blue Chip Economic Indicators**® please contact Randell Moore at randy.moore@wolterskluwer.com or call him at (816) 931-0131.*

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Real GDP Still Expected To Rebound Smartly Following Q1 Contraction

Domestic Commentary The consensus forecast of annual U.S. economic growth in 2015 fell for a fourth straight month, but the decline was attributable to a nearly full percentage point downward revision in the latest estimate of Q1 growth in real (inflation-adjusted) Gross Domestic Product (GDP) from the Bureau of Economic Analysis (BEA). The consensus still predicts that the weakness last quarter in GDP largely resulted from temporary factors – West Coast port slowdown and a harsher-than-usual winter – coupled with seasonal adjustment problems that have bedeviled BEA's estimates of Q1 GDP for years. As a result, the pace of growth is expected by the consensus to snap back this quarter and that real GDP will grow at an above-trend rate over the second half of this year. While the pace of the expansion is forecast to decelerate slightly over the course of 2016, the consensus still forecasts that annual growth next year will exceed that in 2015.

Inflation also is expected to rebound in Q2 following its extreme weakness witnessed over the past two quarters. Much of this softness resulted from the plunge in crude oil and related product prices since last summer. However, crude oil prices bottomed in late January/early February and have rebounded a good bit since, lifting monthly measures of headline inflation. Moreover, core inflation figures also have firmed recently, helping to alleviate concerns about spill-over effects into the general price level from the prior drop in oil prices.

The consensus predicts labor markets will continue to tighten over the forecast horizon. Job growth is expected to be somewhat slower this year than last, hampered by a lack of skilled workers in some industries. However, employment still is forecast to remain sufficiently strong enough to push the unemployment rate to 5.0% or lower by the beginning of next year. Importantly, there are already signs of increased labor compensation – the Q1 increase in the Labor Cost Index and May's increase in average hourly earnings – and a further acceleration in wage and salary growth is anticipated by most analysts.

Against the backdrop of faster economic growth, a sustained rebound in inflation, and further tightening of labor market conditions, the consensus continues to predict that the Federal Reserve will begin a gradual increase in interest rates this year, most likely starting at the Federal Open Market Committee's (FOMC) September 16th-17th meeting. By the end of 2016, the federal funds rate now is projected by the consensus to be in the vicinity of 1.75%. The FOMC remains "data dependent", however, so any deviation in economic or financial conditions from those expected by Fed policymakers' could delay the onset of rate hikes and the speed at which they are enacted.

Real GDP contracted 0.7% (q/q, saar) in Q1 of this year, according to BEA's latest estimate, 0.9 of a percentage point less than originally estimated by the government. The downward revision primarily resulted from greater than expected drag from net exports and a smaller contribution to GDP from inventories. Estimated growth in residential investment was revised up and the contraction in business investment was smaller than first thought. Growth in personal consumption expenditures (PCE) was little changed.

As mentioned earlier, faulty seasonal adjustment by BEA likely contributed to an understatement of GDP growth in Q1. In 15 of the past 20 years, real GDP growth in the initial quarter of each year has fallen well short of that in the other three quarters of the year. Indeed, average real GDP growth in Q1 over the past 20 years has averaged just 1.5% (q/q, saar) versus average growth of 2.9% in the other three quarters of year. Several private sector studies suggest the problem of this "residual seasonality" is real and that GDP in Q1 is being understated by perhaps a percentage point or more. The BEA has announced it is working on this problem and that the July 30th release of its annual revision to the National Income and Product Accounts data will reflect its efforts. By themselves, BEA's effort to address the "residual seasonality" problem should merely serve to smooth out the quarter-to-quarter changes in GDP's growth rate and not affect its estimates of the annual change.

The consensus forecasts that real GDP will grow 2.7% (q/q saar) in the current quarter, 0.2 of a percentage point slower than forecast a month ago. However, the forecast of growth in Q3 increased by 0.1 of a percentage point to 3.2%, while the forecast of Q4 growth stayed at 3.0%. The consensus forecast now projects that real GDP will increase 2.2% year-over-year (y/y) in 2015 and grow by 2.0% measured fourth quarter over fourth quarter (q4/q4). Both estimates declined by 0.3 of a percentage point from a month earlier and are 0.2 of a point less than registered in 2014.

The consensus assumption of a significant rebound in GDP growth over the remainder of this year is premised on a number of factors. Annualized real PCE growth over the remaining quarters of this year is predicted to surpass that in Q1 by about a percentage point. Nonresidential fixed business investment is expected to be less of a drag on GDP this quarter than last as the hit to the oil and gas extraction sector from lower prices lessens. Growth in residential investment also is widely expected to improve on its Q1 growth rate of 5.0% (q/q, saar). Government spending, which over the past several years has tended to be softer in Q1 and Q4 than in Q2 and Q3, will likely bounce higher this quarter and next. Inventories, which currently sit at an elevated level compared to sales, are expected to be a fairly significant drag on GDP this quarter, but likely neither add nor subtract much from GDP in the second half of this year.

For all of 2015, real PCE is forecast to expand 2.9% y/y, 0.2 of a percentage point less than last month. Real DPI is projected to increase 3.4% y/y, down 0.1 of a point from a month ago. The forecast of this year's y/y change in real nonresidential fixed investment inched up by 0.1 of a percentage point to 3.6%. The forecast of the y/y change in total industrial production slipped 0.2 of a percentage point to 2.3%. Auto and light trucks sales are expected to total 16.9 million units this year, up slightly from a month ago. However, the forecast for total housing starts slid to 1.10 million units. The consensus estimate of this year's real net export deficit swelled by another $20 billion to $542.5 billion, but trade is expected to add to GDP this quarter. The unemployment rate this year still is expected to average 5.4%. The CPI still is forecast to rise just 0.2% y/y in 2015, but increase 0.8% q4/q4. The GDP price index still is forecast to increase 1.0% y/y and 1.3% q4/q4.

The consensus forecast of y/y real GDP growth in 2016 remained at 2.8% for a third consecutive month, but the estimate of 2016 growth on a q4/q4 basis slipped back by 0.1 of a percentage point to 2.7%. The consensus forecast of y/y growth next year in nominal GDP remained at 4.8% for a fourth consecutive month. Real PCE still is forecast to increase 2.8% y/y and real DPI 2.5%. Real nonresidential fixed investment is forecast to increase 5.0% y/y, the same as a month earlier. Total industrial production is forecast to increase 3.0% y/y, down 0.1 of a percentage point from a month ago. Also unchanged were predictions that the CPI and GDP price index will increase 2.2% y/y and 1.9% y/y, respectively. Also unchanged were estimates that total auto and light trucks will hit 17.1 million units in 2016 and that housing starts will total 1.26 million units. The unemployment rate now is forecast to average 4.9% next year, 0.1 of a point less than last month.

International Commentary The consensus forecast of 2015 y/y real GDP growth in the Eurozone remained at 1.5% this month but the 2016 forecast fell to 1.7%. Consensus estimates of Chinese real GDP growth fell again this month, dropping to 6.8% for 2015 and 6.6% for 2016. The forecast of Canadian real GDP growth in 2015 also fell again, dropping to 1.9%. Growth of 2.2% in 2016 still is predicted. Russian real GDP is forecast to contract 3.6% this year and grow just 0.2% in 2016. Brazil's economy is forecast to contract 1.0% in 2015, but grow 1.1% next year *(see pages 6-7).*

Special Questions Almost 87% of the panelists believe the FOMC will begin to raise interest rates at its September 16th-17th meeting. A bit more than one-third of the panelists responding said the Fed has held interest rates near zero for too long *(see page 14).*

GREEN indicates the Blue Chip consensus forecast of real GDP growth over the next four quarters is 3.0 percent or more.
YELLOW cautions that the consensus forecast of real GDP growth over the next four quarters is between 1.5 percent and 2.9 percent.
RED warns that the consensus forecast of real GDP growth of real GDP growth over the next four quarters is less than 1.5 percent.

2015 Real GDP Forecast Drops To 2.2%

JUNE 2015 Forecast For 2015 SOURCE:	Percent Change 2015 From 2014 (Full Year-Over-Prior Year)									Average For 2015			Total Units-2015		2015
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Real GDP (Chained) (2009$)	GDP Price Index	Nominal GDP (Cur.$)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income (2009$)	Personal Cons. Exp. (2009$)	Non-Res. Fix. Inv. (2009$)	Corp. Profits (Cur.$)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto&Light Truck Sales (Mil.)	Net Exports (2009$)
Ford Motor Company*	2.8 H	1.0	3.8	0.4	2.7	3.1	3.4 H	4.1	na	0.6 H	2.2	5.2 L	1.08	na	-520.9
PNC Financial Services Group	2.8 H	1.1	3.9 H	0.4	2.5	3.6	3.1	3.4	na	0.2	2.1	5.4	1.01	16.9	-510.0
Naroff Economic Advisors*	2.6	1.0	3.6	0.2	2.7	4.0	3.3	3.0	4.0	0.3	2.5	5.3	1.16	16.7	-520.0
Inforum - Univ. of Maryland	2.5	1.0	3.6	0.1	2.8	3.6	3.1	4.0	3.2	0.3	2.2	5.4	1.11	16.9	-523.4
SOM Economics, Inc.	2.5	0.9	3.4	0.3	2.3	3.4	2.7	4.4	1.0	0.1	2.3	5.3	1.10	17.2 H	-504.0
Comerica	2.4	1.0	3.3	0.3	2.6	3.6	2.7	4.9	na	0.1	2.1	5.3	1.00 L	16.8	-513.4
Economist Intelligence Unit	2.4	1.1	3.5	0.5	3.0	3.0	3.0	4.5	na	0.3	2.5	5.4	1.15	16.8	-510.0
High Frequency Economics	2.4	1.2	3.7	0.5	2.1	3.5	3.0	4.0	-1.5	0.4	2.4	5.2 L	1.13	17.2 H	-558.3
RBC Capital Markets	2.4	1.0	3.5	0.5	3.8 H	na	2.9	3.5	na	0.2	2.4	5.2 L	1.11	16.9	-519.0
Societe Generale	2.4	1.1	3.5	0.2	2.9	3.3	2.9	3.4	1.5	0.2	2.4	5.3	1.13	16.9	-540.0
Standard & Poors Corp.*	2.4	1.1	3.5	0.1	2.5	3.4	3.2	3.4	-1.1	0.1	2.2	5.3	1.13	16.8	-533.9
Swiss Re	2.4	1.2	3.6	0.0	2.7	3.8	2.9	4.9	5.6	0.2	2.3	5.3	1.14	16.7	-558.5
Turning Points (Micrometrics)	2.4	1.0	3.4	0.1	2.5	3.5	2.9	4.8	2.1	0.0 L	2.0 L	5.4	1.01	17.1	-547.0
Amherst Pierpont Securities	2.3	1.0	3.3	0.6 H	1.4	3.3	2.8	4.1	-2.0	0.2	2.5	5.4	1.17	16.8	-527.0
BNP Paribas North America	2.3	na	na	0.4	3.0	4.1 H	2.8	1.2 L	5.6	na	2.1	5.2 L	1.10	na	-534.0
FedEx Corporation	2.3	1.0	3.2	0.3	2.2	3.6	2.8	3.8	0.2	0.2	2.3	5.4	1.12	16.8	-551.5
Moody's Capital Markets*	2.3	0.9	3.3	0.0	2.4	3.5	2.9	3.8	1.5	0.1	2.2	5.4	1.12	16.9	-528.8
MUFG Union Bank	2.3	1.2	3.5	0.5	2.3	na	3.1	5.7	7.0 H	0.3	2.4	5.2 L	1.20 H	16.8	-500.0
Northern Trust Company*	2.3	0.9	3.2	0.1	2.5	3.1	3.0	3.3	na	0.2	2.3	5.4	1.20 H	16.9	-532.5
RDQ Economics	2.3	0.8 L	3.1	0.1	2.8	3.5	2.8	4.7	6.1	0.3	2.3	5.3	1.00 L	17.0	-548.0
UBS	2.3	1.1	3.3	0.2	2.7	3.1	2.9	2.8	na	0.3	2.1	5.3	1.20	na	-539.2
Action Economics	2.2	1.0	3.2	0.4	1.9	3.2	1.6 L	2.9	-1.9	0.5	2.9 H	5.4	1.10	na	-487.2 H
Bank of America Merrill Lynch	2.2	0.8 L	3.0	0.4	1.6	na	3.0	2.9	na	0.2	2.3	5.4	1.10	17.1	-552.4
BMO Capital Markets*	2.2	1.1	3.4	0.2	1.8	3.7	2.9	3.7	-0.4	0.1	2.3	5.3	1.13	17.0	-554.0
Credit Suisse	2.2	1.0	3.2	0.2	2.2	na	2.8	2.8	1.7	na	2.3	5.3	1.05	na	-531.8
General Motors	2.2	1.0	3.2	0.3	2.1	3.5	3.2	2.4	-0.6	0.1	2.3	5.4	1.09	na	-517.0
Goldman Sachs & Co.**	2.2	0.8	3.0	0.2	2.9	3.5	3.2	2.3	na	0.3	2.4	5.4	1.10	na	-551.0
Morgan Stanley*	2.2	1.0	3.2	0.4	2.9	3.3	2.9	2.9	na	0.1	2.2	5.4	1.12	17.0	-549.7
National Assn. of Home Builders	2.2	0.9	3.1	0.1	1.9	3.3	2.8	3.4	na	0.2	2.1	5.5 H	1.07	16.5 L	-550.0
UCLA Business Forecasting Proj.*	2.2	1.2	3.4	0.0	1.7	3.4	3.0	3.6	4.4	0.2	2.2	5.4	1.16	16.9	-546.8
AIG	2.1	0.8	3.3	0.1	1.3 L	3.2	3.1	2.5	-0.5	0.3	2.2	5.4	1.09	16.8	-527.0
Barclays*	2.1	1.2	3.4	0.2	2.4	na	2.9	3.5	na	na	2.1	5.3	1.07	na	-567.0
Eaton Corporation	2.1	0.9	3.0	0.5	2.7	3.1	2.9	3.6	5.0	0.3	2.5	5.3	1.14	16.7	-510.8
Econoclast	2.1	1.3	3.4	0.3	2.0	3.4	2.7	3.2	3.5	0.3	2.3	5.4	1.11	16.9	-548.0
Fannie Mae	2.1	1.0	3.2	0.2	2.2	3.1	3.0	2.6	0.3	0.1	2.1	5.4	1.11	16.9	-547.0
MacroFin Analytics	2.1	0.8 L	2.9 L	0.0	2.6	3.4	2.8	3.7	-1.3	0.3	2.4	5.5 H	1.10	16.7	-514.6
Mesirow Financial	2.1	1.0	3.1	0.1	1.8	3.4	3.0	3.0	2.3	0.1	2.3	5.4	1.10	16.9	-552.7
National Assn. of Realtors	2.1	1.0	3.1	0.1	2.7	3.7	2.9	3.0	0.0	0.2	2.3	5.4	1.14	16.7	-565.0
RBS	2.1	1.0	3.2	0.3	2.0	3.6	2.9	3.7	4.0	0.1	2.3	5.4	1.10	16.8	-555.0
U.S. Chamber of Commerce	2.1	0.8 L	2.9 L	-0.2	2.9	3.5	2.9	3.6	3.0	0.2	2.3	5.4	1.08	na	-556.9
Wells Capital Management	2.1	1.1	3.2	0.1	2.7	3.6	2.9	4.1	-2.5	0.0 L	2.1	5.3	1.02	16.8	-583.0
Oxford Economics	2.1	1.2	3.3	0.3	2.0	3.1	2.8	3.4	-2.6	0.1	2.2	5.3	1.13	16.7	-543.2
ACT Research	2.0 L	1.1	3.2	0.2	1.9	3.3	2.7	3.8	na	0.2	2.2	5.3	1.13	17.0	-576.4
Conference Board*	2.0 L	1.0	3.0	0.0	2.2	3.5	2.8	3.1	-3.1 L	0.1	2.2	5.3	1.09	16.7	-557.9
Daiwa Capital Markets America	2.0 L	1.0	3.0	0.2	2.1	3.5	2.8	3.4	-2.9	0.2	2.2	5.4	1.07	16.8	-560.0
Georgia State University*	2.0 L	0.9	2.9 L	-0.3 L	2.5	3.5	2.9	3.2	4.3	0.1	2.3	5.5 H	1.11	16.8	-610.6 L
IHS Global Insight	2.0 L	1.0	3.1	-0.1	na	2.4 L	3.0	6.3 H	-0.2	0.2	2.2	5.5 H	1.10	17.0	-559.9
J P MorganChase	2.0 L	1.0	2.9 L	0.4	2.3	3.4	2.8	4.7	-1.1	na	2.2	5.3	1.09	16.7	-563.8
Macroeconomic Advisers, LLC**	2.0 L	1.0	3.1	0.2	1.6	3.4	2.9	2.5	0.5	0.1	2.3	5.3	1.08	16.9	-543.8
Nomura Securities	2.0 L	0.9	2.9	0.4	2.1	3.7	3.2	2.7	na	0.0 L	2.2	5.4	1.04	16.7	-585.9
Point72 Asset Management	2.0 L	0.9	2.9	0.1	2.0	3.4	2.8	3.1	2.4	0.1	2.3	5.3	1.10	16.8	-557.2
Wells Fargo	2.0 L	1.7 H	3.7	0.2	2.2	3.6	2.8	3.4	3.9	0.4	2.2	5.4	1.13	17.0	-562.8
2015 Consensus: June Avg.	**2.2**	**1.0**	**3.3**	**0.2**	**2.3**	**3.4**	**2.9**	**3.6**	**1.4**	**0.2**	**2.3**	**5.4**	**1.10**	**16.9**	**-542.5**
Top 10 Avg.	2.5	1.2	3.6	0.5	3.0	3.7	3.2	4.9	5.0	0.4	2.5	5.4	1.17	17.1	-508.6
Bottom 10 Avg.	2.0	0.8	2.9	0.0	1.7	3.1	2.6	2.5	-2.0	0.1	2.1	5.3	1.03	16.7	-573.4
May Avg.	2.5	1.0	3.5	0.2	2.5	3.5	3.1	3.5	3.3	0.2	2.2	5.4	1.11	16.8	-522.2
Historical data: 2011	1.6	2.1	3.7	3.2	3.3	2.5	2.3	7.7	4.0	0.1	2.8	9.0	0.61	12.7	-459.4
2012	2.3	1.8	4.2	2.1	3.8	3.0	1.8	7.2	11.3	0.1	1.8	8.1	0.78	14.4	-452.5
2013	2.2	1.5	3.7	1.5	2.9	-0.2	2.4	3.0	4.2	0.1	2.4	7.4	0.92	15.5	-420.4
2014	2.4	1.5	3.9	1.6	4.1	2.5	2.5	6.3	-0.8	0.0	2.5	6.2	1.00	16.4	-452.6
Number Of Forecasts Changed From A Month Ago:															
Down	45	13	42	12	31	27	33	16	25	9	3	5	9	7	42
Same	6	29	7	24	9	12	16	9	7	38	26	38	26	20	6
Up	1	9	2	16	11	8	3	27	5	1	23	9	17	16	4
June Median	2.2	1.0	3.2	0.2	2.3	3.4	2.9	3.4	1.3	0.2	2.3	5.4	1.10	16.8	-547.0
June Diffusion Index	8 %	46 %	11 %	54 %	30 %	30 %	21 %	61 %	23 %	42 %	69 %	54 %	58 %	60 %	13 %

*Former winner of annual Lawrence R. Klein Award for Blue Chip Forecast Accuracy. **Denotes two-time winner. ***Denotes three-time winner.

2016 Real GDP Forecast Stays At 2.8% For A Third Month

JUNE 2015 Forecast For 2016 SOURCE:	Percent Change 2016 From 2015 (Full Year-Over-Prior Year)									Average For 2016			Total Units-2016		2016
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Real GDP (Chained) (2009$)	GDP Price Index	Nominal GDP (Cur.$)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income (2009$)	Personal Cons. Exp. (2009$)	Non-Res. Fix. Inv. (2009$)	Corp. Profits (Cur.$)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto&Light Truck Sales (Mil.)	Net Exports (2009$)
Turning Points (Micrometrics)	3.3 H	1.9	5.2	2.0	2.6	2.7	2.8	6.2	9.4	0.1 L	2.4 L	5.0	1.10	18.2 H	-568.9
Naroff Economic Advisors*	3.2	2.6 H	5.8	2.7	3.3	3.0	2.9	4.8	5.7	2.0 H	4.2 H	4.9	1.30	17.0	-570.0
Swiss Re	3.1	1.8	5.0	2.0	3.0	3.1	3.0	7.3 H	6.0	1.5	3.2	4.7	1.38	16.7	-644.6
Bank of America Merrill Lynch	3.0	1.6	4.6	2.1	2.6	na	3.1	4.5	na	0.9	2.6	5.0	1.30	18.1	-586.1
Daiwa Capital Markets America	3.0	1.9	5.0	2.0	3.7	3.1	3.0	6.4	1.1	1.4	3.0	5.0	1.15	16.9	-627.0
National Assn. of Home Builders	3.0	1.7	4.8	2.0	3.8	2.0	2.6	4.9	na	1.1	2.7	5.3 H	1.30	16.3 L	-561.0
National Assn. of Realtors	3.0	1.9	5.0	2.7	3.2	2.5	2.7	3.8	3.0	1.6	3.2	5.2 L	1.39	16.8	-580.0
RBC Capital Markets	3.0	2.2	5.3	2.1	5.6 H	na	2.6	4.9	na	1.1	3.1	4.2	1.20	17.2	-490.0
RBS	3.0	1.7	4.8	2.1	2.4	2.7	2.8	5.9	4.0	1.2	2.8	5.0	1.20	16.8	-570.0
Societe Generale	3.0	2.1	5.2	2.2	3.0	2.8	2.6	4.4	0.7	1.0	3.0	4.8	1.29	17.2	-548.0
U.S. Chamber of Commerce	3.0	1.6	4.7	1.8	3.6	2.4	3.0	5.8	3.9	1.1	3.0	5.1	1.25	na	-591.0
UCLA Business Forecasting Proj.*	3.0	2.4	5.5	2.6	3.4	2.3	2.8	7.2	10.4 H	1.2	3.2	5.0	1.37	17.2	-628.2
Action Economics	2.9	1.9	4.9	2.3	2.7	2.6	1.8 L	3.3	4.9	1.8	3.4	5.0	1.20	na	-459.3 H
Amherst Pierpont Securities	2.9	2.1	5.1	3.1	2.2	2.6	2.6	5.2	5.5	1.7	4.0	4.9	1.48 H	16.9	-515.0
Credit Suisse	2.9	1.6	4.5	1.8	3.7	na	3.0	3.8	4.1	na	2.7	4.7	1.15	na	-564.0
FedEx Corporation	2.9	1.9	4.8	2.3	3.2	2.7	2.8	5.2	5.0	1.5	3.3	5.1	1.35	17.1	-551.0
High Frequency Economics	2.9	2.4	5.4	2.7	3.6	2.8	2.8	5.4	4.5	1.9	3.4	4.5	1.27	17.7	-574.5
IHS Global Insight	2.9	2.0	4.9	1.7	na	2.4	3.0	6.3	8.4	1.2	2.9	5.1	1.31	17.3	-627.0
Macroeconomic Advisers, LLC**	2.9	1.8	4.7	2.0	2.1	2.2	3.2	3.4	3.6	1.0	3.3	5.0	1.32	17.3	-550.6
Mesirow Financial	2.9	1.7	4.6	1.9	2.2	2.2	3.0	4.5	4.7	1.0	3.4	5.0	1.35	17.0	-567.5
MUFG Union Bank	2.9	2.5	5.4	3.4 H	2.7	na	2.9	7.0	7.0	1.3	3.2	4.7	1.40	17.0	-540.0
PNC Financial Services Group	2.9	2.0	4.9	2.4	2.7	2.5	2.8	3.8	na	1.0	2.4 L	4.9	1.08	17.2	-515.3
RDQ Economics	2.9	1.8	4.8	2.1	3.3	2.8	2.9	3.4	3.9	1.8	3.4	4.5	1.10	17.5	-580.0
SOM Economics, Inc.	2.9	1.6	4.6	2.2	3.6	2.4	2.5	4.8	5.5	1.1	2.8	4.6	1.23	17.9	-475.0
Wells Fargo	2.9	2.0	4.9	2.2	3.2	2.7	2.8	5.8	5.3	1.7	2.7	5.0	1.22	17.1	-630.1
Oxford Economics	2.8	2.3	5.2	2.3	3.3	2.5	2.8	4.7	1.8	0.7	2.6	5.0	1.37	16.9	-550.3
BNP Paribas North America	2.8	na	na	2.5	4.3	3.3 H	3.2	4.7	1.8	na	2.7	4.6	1.30	na	-578.0
Comerica	2.8	2.0	4.8	2.3	4.0	2.5	2.1	7.1	na	0.9	2.9	4.8	1.07	16.7	-534.7
General Motors	2.8	1.8	4.6	2.3	2.1	2.5	2.8	3.8	3.3	1.1	3.3	4.9	1.30	na	-524.0
Georgia State University*	2.8	1.6	4.4	2.2	3.4	2.5	3.0	5.8	6.5	1.2	3.0	5.2	1.19	16.9	-705.9 L
Goldman Sachs & Co.**	2.8	1.4	4.3	2.1	3.5	2.4	3.5 H	4.8	na	1.3	3.1	5.0	1.32	na	-665.1
Inforum - Univ. of Maryland	2.8	1.9	4.8	2.3	3.0	2.8	2.8	5.1	5.0	1.4	3.1	5.1	1.29	16.9	-537.1
Northern Trust Company*	2.8	2.0	4.9	2.1	3.5	2.8	2.8	4.0	na	1.0	3.3	5.3 H	1.30	17.1	-532.2
Standard & Poors Corp.*	2.8	2.2	5.1	2.2	3.9	2.2	2.8	5.2	3.0	1.1	2.9	5.0	1.37	17.0	-550.1
UBS	2.8	2.3	5.1	2.4	2.5	1.7	2.9	6.7	na	1.4	2.7	4.8	1.31	na	-548.8
Wells Capital Management	2.8	2.3	5.1	2.0	3.4	2.6	2.9	6.1	3.8	0.9	2.7	5.0	1.04 L	16.9	-648.0
Fannie Mae	2.7	1.7	4.4	2.0	2.8	2.0	2.9	4.5	1.8	0.8	2.4 L	5.0	1.32	17.5	-589.0
Ford Motor Company*	2.7	1.9	4.6	2.4	2.0 L	1.9	3.1	3.0 L	na	1.6	3.0	4.9	1.25	na	-527.2
MacroFin Analytics	2.7	1.5	4.2	1.8	4.1	2.6	2.7	5.0	4.9	1.9	3.8	5.3 H	1.10	16.5	-473.8
Moody's Capital Markets*	2.7	1.7	4.4	1.7	3.7	2.3	2.6	3.7	2.7	0.8	2.8	5.0	1.26	17.0	-548.4
Morgan Stanley*	2.7	1.9	4.6	2.1	2.0 L	2.1	2.5	3.9	na	1.0	na	4.9	1.31	17.4	-568.0
ACT Research	2.6	2.1	4.8	2.0	2.2	1.4 L	2.5	5.7	na	1.4	2.5	5.0	1.27	17.5	-650.7
AIG	2.6	1.4	4.5	2.0	2.0 L	1.9	3.2	3.6	1.7	1.3	3.1	5.1	1.30	16.9	-596.2
BMO Capital Markets*	2.6	2.1	4.7	0.8 L	2.4	2.6	3.1	4.4	5.2	1.0	2.7	4.7	1.31	17.1	-632.0
Eaton Corporation	2.6	1.3	4.0 L	1.7	3.0	2.3	2.7	3.6	5.4	1.3	3.1	5.2	1.20	16.8	-522.8
Barclays*	2.5	2.1	4.7	2.0	2.5	na	2.8	5.2	na	na	na	4.6	1.19	na	-610.0
Economist Intelligence Unit	2.5	2.1	4.6	2.2	3.2	2.3	2.4	6.2	na	1.4	3.3	5.1	1.25	16.8	-540.0
J P MorganChase	2.5	1.8	4.3	2.1	2.5	2.4	2.7	5.5	5.2	na	na	4.7	1.20	16.8	-619.2
Nomura Securities	2.5	1.5	4.0 L	2.2	2.3	3.1	3.0	4.8	na	0.4	2.8	5.0	1.24	16.9	-668.8
Point72 Asset Management	2.5	1.8	4.3	2.1	3.2	2.4	2.5	5.5	3.5	1.2	3.0	4.4	1.20	17.1	-606.8
Econoclast	2.4	2.3	4.7	2.4	2.5	2.6	2.6	4.5	3.9	1.0	2.8	4.9	1.22	16.9	-603.0
Conference Board*	2.2 L	1.8	4.1	2.0	2.5	2.5	2.4	3.9	-0.4 L	0.5	2.7	4.7	1.32	16.4	-591.1
2016 Consensus: June Avg.	**2.8**	**1.9**	**4.8**	**2.2**	**3.0**	**2.5**	**2.8**	**5.0**	**4.4**	**1.2**	**3.0**	**4.9**	**1.26**	**17.1**	**-573.8**
Top 10 Avg.	3.1	2.4	5.3	2.7	4.0	3.0	3.1	6.7	7.0	1.8	3.6	5.2	1.38	17.6	-503.5
Bottom 10 Avg.	2.5	1.5	4.2	1.7	2.2	2.0	2.4	3.5	1.7	0.7	2.7	4.6	1.12	16.7	-650.0
May Avg.	2.8	1.9	4.8	2.2	3.1	2.5	2.8	5.0	3.9	1.3	3.0	5.0	1.26	17.1	-554.4
Number Of Forecasts Changed From A Month Ago:															
Down	15	13	18	19	24	14	14	12	8	12	7	12	6	6	35
Same	27	32	20	22	16	24	33	20	10	35	30	34	35	30	8
Up	9	5	12	10	10	8	4	19	18	0	11	5	10	6	8
June Median	2.8	1.9	4.8	2.1	3.0	2.5	2.8	4.9	4.3	1.2	3.0	5.0	1.28	17.0	-569.5
June Diffusion Index	44 %	42 %	44 %	41 %	36 %	43 %	40 %	57 %	64 %	37 %	54 %	43 %	54 %	50 %	24 %

***Former winner of annual Lawrence R. Klein Award for Blue Chip Forecast Accuracy. **Denotes two-time winner. ***Denotes three-time winner.**

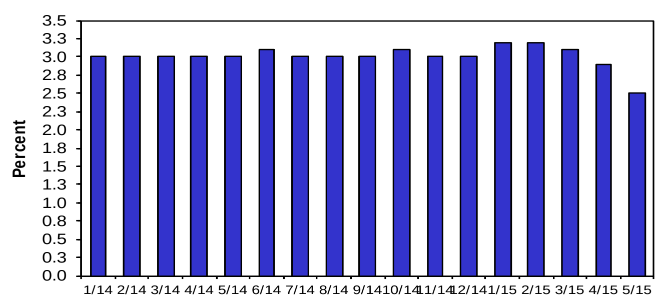
BASIC DATA SOURCES: [1]Gross Domestic Product (GDP), chained 2009$, National Income and Product Accounts (NIPA), Bureau of Economic Analysis (BEA); [2]GDP Chained Price Index, NIPA, BEA; [3]GDP, current dollars, NIPA, BEA; [4]Consumer Price Index-All Urban Consumers, Bureau of Labor Statistics (BLS); [5]Total Industrial Production, Federal Reserve Board (FRB); [6]Disposable Personal Income, 2009$, NIPA, BEA; [7]Personal Consumption Expenditures, 2009$, NIPA, BEA; [8]Nonresidential Fixed Investment, 2009$, NIPA, BEA; [9]Corporate Profits Before Taxes, current dollars, with inventory valuation and capital consumption adjustments, NIPA, BEA; [10]Treasury Bill Rate, 3-month, secondary market, bank discount basis, FRB; [11]Treasury note yield, 10-year, constant maturity basis, FRB; [12]Unemployment Rate, civilian work force, BLS; [13]Housing Starts, Bureau of Census; [14]Total U.S. Auto and Light Truck Sales (includes imports), BEA; [15]Net Exports of Goods and Services, 2009$, NIPA, BEA.

Previous Consensus Forecasts

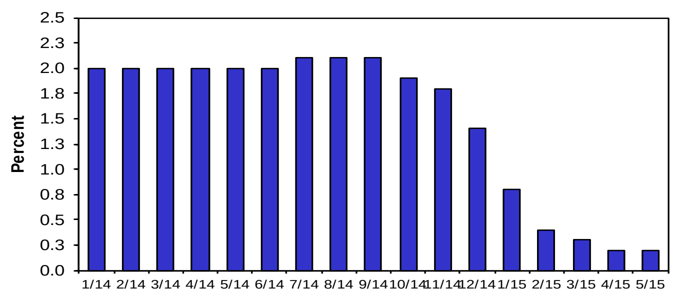
Consensus Forecasts For 2015	Real GDP Chained ('2009$)	GDP Price Index	Nominal GDP (Cur. $)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income ('2009$)	Personal Cons. Exp. ('2009$)	Non-Res. Fix. Inv. ('2009$)	Corp. Profits (Cur. $)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto/Truck Sales (Mil.)	Net Exports ('2009$)
January 2014 Consensus	3.0	1.9	4.9	2.0	3.5	2.8	2.8	5.4	5.0	0.5	3.7	6.3	1.30	16.5	-418.5
February 2014 Consensus	3.0	1.9	4.9	2.0	3.5	2.8	2.8	5.6	5.1	0.5	3.7	6.1	1.31	16.4	-388.2
March 2014 Consensus	3.0	1.9	4.9	2.0	3.6	2.8	2.8	5.7	5.4	0.5	3.7	5.9	1.31	16.4	-392.9
April 2014 Consensus	3.0	1.9	4.9	2.0	3.6	2.9	2.9	5.7	5.6	0.5	3.7	5.9	1.31	16.4	-398.5
May 2014 Consensus	3.0	1.9	4.9	2.0	3.6	2.9	2.9	5.7	5.2	0.5	3.6	5.9	1.27	16.4	-410.7
June 2014 Consensus	3.1	1.9	5.0	2.0	3.6	2.9	2.8	5.7	6.0	0.5	3.5	5.8	1.26	16.5	-421.4
July 2014 Consensus	3.0	1.9	5.0	2.1	3.6	2.8	2.8	5.6	5.8	0.5	3.5	5.8	1.23	16.6	-436.4
August 2014 Consensus	3.0	1.9	5.0	2.1	3.7	2.8	2.8	5.5	5.8	0.5	3.4	5.7	1.20	16.7	-456.4
September 2014 Consensus	3.0	2.0	5.0	2.1	3.6	2.8	2.7	5.7	6.4	0.5	3.3	5.7	1.20	16.7	-455.1
October 2014 Consensus	3.1	1.9	5.0	1.9	3.5	2.9	2.7	6.0	6.6	0.5	3.2	5.6	1.19	16.8	-450.1
November 2014 Consensus	3.0	1.8	4.8	1.8	3.6	2.8	2.7	5.8	6.5	0.4	3.0	5.6	1.18	16.8	-436.1
December 2014 Consensus	3.0	1.7	4.7	1.4	3.5	2.9	2.8	5.9	7.0	0.4	2.9	5.5	1.17	16.8	-448.2
January 2015 Consensus	3.2	1.5	4.7	0.8	3.8	3.1	3.0	5.9	7.0	0.4	2.7	5.5	1.17	16.9	-457.3
February 2015 Consensus	3.2	1.1	4.3	0.4	3.9	3.3	3.3	5.1	6.3	0.4	2.4	5.4	1.16	16.9	-475.5
March 2015 Consensus	3.1	1.1	4.3	0.3	3.8	3.5	3.3	5.3	5.6	0.3	2.4	5.4	1.16	16.9	-491.2
April 2015 Consensus	2.9	1.1	4.0	0.2	3.1	3.5	3.2	5.0	4.3	0.3	2.3	5.4	1.14	16.8	-493.5
May 2015 Consensus	2.5	1.0	3.5	0.2	2.5	3.5	3.1	3.5	3.3	0.2	2.2	5.4	1.11	16.8	-522.2
June 2015 Consensus	**2.2**	**1.0**	**3.3**	**0.2**	**2.3**	**3.4**	**2.9**	**3.6**	**1.4**	**0.2**	**2.3**	**5.4**	**1.10**	**16.9**	**-542.5**
Change From Jan. 2014 Forecast	-0.8	-0.9	-1.6	-1.8	-1.2	0.6	0.1	-1.8	-3.6	-0.3	-1.4	-0.9	-0.20	0.4	-124.0
Forecast High	3.2	2.0	5.0	2.1	3.9	3.5	3.3	6.0	7.0	0.5	3.7	6.3	1.31	16.9	-388.2
Forecast Low	2.2	1.0	3.3	0.2	2.3	2.8	2.7	3.5	1.4	0.2	2.2	5.4	1.10	16.4	-542.5

Consensus Forecasts For 2016	Real GDP Chained ('2009$)	GDP Price Index	Nominal GDP (Cur. $)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income ('2009$)	Personal Cons. Exp. ('2009$)	Non-Res. Fix. Inv. ('2009$)	Corp. Profits (Cur. $)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto/Truck Sales (Mil.)	Net Exports ('2009$)
January 2015 Consensus	2.9	2.0	4.9	2.3	3.3	2.8	2.7	5.4	4.1	1.7	3.5	5.1	1.30	17.0	-480.4
February 2015 Consensus	2.9	2.0	4.9	2.3	3.3	2.8	2.8	5.2	4.1	1.6	3.2	5.0	1.30	17.1	-499.5
March 2015 Consensus	2.9	1.9	4.8	2.2	3.2	2.7	2.8	5.2	4.1	1.6	3.2	5.0	1.30	17.0	-523.7
April 2015 Consensus	2.8	1.9	4.8	2.2	3.1	2.6	2.8	5.2	4.0	1.4	3.1	5.0	1.28	17.0	-530.0
May 2015 Consensus	2.8	1.9	4.8	2.2	3.1	2.5	2.8	5.0	3.9	1.3	3.0	5.0	1.26	17.1	-544.4
June 2015 Consensus	**2.8**	**1.9**	**4.8**	**2.2**	**3.0**	**2.5**	**2.8**	**5.0**	**4.4**	**1.2**	**3.0**	**4.9**	**1.26**	**17.1**	**-573.8**
Change From Jan. 2015 Forecast	-0.1	-0.1	-0.1	-0.1	-0.3	-0.3	0.1	-0.4	0.3	-0.5	-0.5	-0.2	-0.04	0.1	-93.4
Forecast High	2.9	2.0	4.9	2.3	3.3	2.8	2.8	5.4	4.4	1.7	3.5	5.1	1.30	17.1	-480.4
Forecast Low	2.8	1.9	4.8	2.2	3.0	2.5	2.7	5.0	3.9	1.2	3.0	4.9	1.26	17.0	-573.8

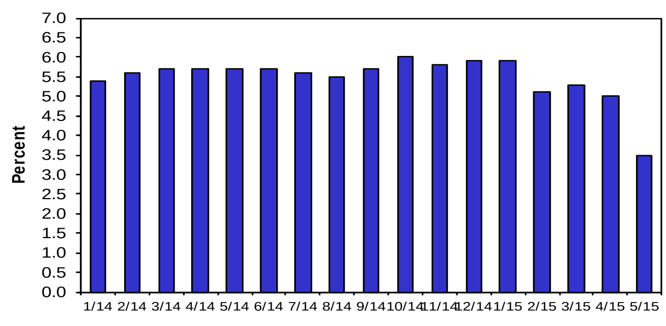
Consensus Forecasts Of Y/Y % Change In Real GDP In 2015



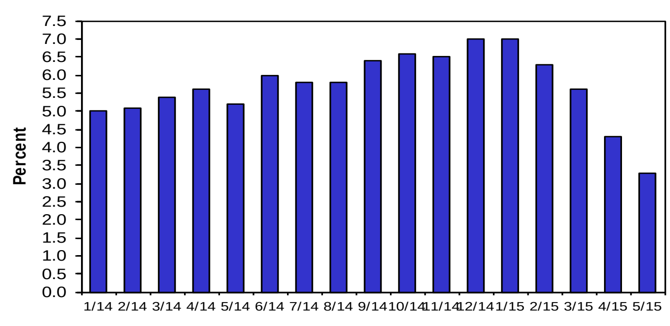
Consensus Forecasts Of Y/Y % Change In Consumer Price Index In 2015



Consensus Forecasts Of Y/Y % Change In Real Nonresidential Fixed Investment In 2015



Consensus Forecasts Of Y/Y % Change In Corporate Profits In 2015



3. Blue Chip Consensus: Percent Change From Prior Quarter At Annual Rate And Averages For Quarter.*

Actuals[1]	Real GDP	GDP Price Index	CPI	Producer Price Index	Total Industrial Production	Disposable Personal Income	Personal Consump. Expend.	Unemploy-ment Rate	3-Mo. Treas. Bills	10-Yr. Treas. Notes	Change in Business Inventories	Real Net Exports
	% Change From Prior Quarter At Annual Rate							Average For Quarter				
2014 1Q	-2.1	1.3	2.1	2.3	3.9	3.4	1.2	6.6	0.1	2.8	35.2	-447.2
2Q	4.6	2.1	2.4	2.2	5.7	3.1	2.5	6.2	0.1	2.6	84.8	-460.4
3Q	5.0	1.4	1.2	1.2	4.1	2.4	3.2	6.1	0.0	2.6	82.2	-431.4
4Q	2.2	0.1	-0.9	-0.6	4.6	4.1	4.4	5.7	0.0	2.3	80.0	-471.4
2015 1Q	-0.7	-0.1	-3.1	-4.8	-0.7	5.3	1.8	5.6	0.0	2.0	95.0	-548.4
Blue Chip Forecasts	% Change From Prior Quarter At Annual Rate							Average For Quarter				
2Q Consensus	**2.7**	**1.8**	**2.3**	**0.2**	**1.1**	**2.1**	**2.7**	**5.4**	**0.1**	**2.1**	**77.9**	**-536.8**
Top 10 Avg.	3.7	2.5	3.3	2.0	3.5	3.1	3.5	5.5	0.2	2.3	92.7	-510.5
Bot. 10 Avg.	1.9	1.2	1.0	-1.7	-1.3	1.0	2.0	5.3	0.0	2.0	60.2	-564.0
3Q Consensus	**3.2**	**1.9**	**2.2**	**2.1**	**3.2**	**2.3**	**3.2**	**5.3**	**0.2**	**2.4**	**73.1**	**-543.6**
Top 10 Avg.	4.0	2.4	3.1	3.2	4.5	3.0	3.9	5.4	0.4	2.6	89.7	-506.2
Bot. 10 Avg.	2.6	1.5	1.2	1.1	1.8	1.3	2.6	5.1	0.0	2.2	52.8	-582.5
4Q Consensus	**3.0**	**1.7**	**2.0**	**2.1**	**3.3**	**2.5**	**3.0**	**5.1**	**0.5**	**2.5**	**71.0**	**-553.7**
Top 10 Avg.	3.5	2.3	2.8	2.8	4.4	3.2	3.6	5.3	0.9	2.8	89.8	-504.5
Bot. 10 Avg.	2.5	1.1	1.3	1.4	2.3	1.7	2.6	4.9	0.2	2.3	51.0	-602.8
2016 1Q Consensus	**2.7**	**1.9**	**2.0**	**2.0**	**3.2**	**2.5**	**2.7**	**5.0**	**0.8**	**2.7**	**66.8**	**-563.8**
Top 10 Avg.	3.1	2.5	2.6	2.9	4.6	3.2	3.2	5.3	1.2	3.2	88.7	-508.7
Bot. 10 Avg.	2.3	1.4	1.4	1.2	2.1	1.7	2.3	4.8	0.4	2.4	45.8	-623.5
2Q Consensus	**2.7**	**2.0**	**2.3**	**2.3**	**3.1**	**2.6**	**2.7**	**4.9**	**1.1**	**2.9**	**63.2**	**-573.2**
Top 10 Avg.	3.2	2.5	3.0	3.3	4.2	3.3	3.2	5.2	1.6	3.4	83.0	-509.6
Bot. 10 Avg.	2.2	1.6	1.8	1.6	1.9	1.9	2.3	4.6	0.6	2.5	42.4	-642.9
3Q Consensus	**2.7**	**2.1**	**2.4**	**2.4**	**3.1**	**2.5**	**2.6**	**4.9**	**1.3**	**3.1**	**61.4**	**-581.6**
Top 10 Avg.	3.1	2.5	3.2	3.4	4.3	3.0	3.0	5.2	1.9	3.7	83.7	-512.0
Bot. 10 Avg.	2.2	1.6	2.0	1.6	1.8	1.9	2.2	4.5	0.8	2.6	40.1	-658.7
4Q Consensus	**2.6**	**2.0**	**2.4**	**2.3**	**3.0**	**2.5**	**2.6**	**4.8**	**1.7**	**3.3**	**59.9**	**-591.5**
Top 10 Avg.	3.1	2.5	3.2	3.1	4.1	3.2	3.0	5.1	2.2	3.9	84.3	-512.9
Bot. 10 Avg.	2.0	1.5	1.9	1.6	1.7	1.7	2.1	4.3	1.1	2.7	35.6	-677.2

4. Blue Chip Consensus: Quarterly Annualized Values And Percent Change From Same Quarter In Prior Year.*

Real Gross Domestic Product

	Billions Of Chained 2009$ (SAAR)			% Change From Same Quarter In Prior Year[2]		
	Actual	Forecast[1]		Actual	Forecast	
Quarter	2014	2015	2016	2014	2015	2016
1Q	15831.7	16264.1	**16733.1**	1.9	2.7	**2.9**
2Q	16010.4	**16371.8**	**16846.7**	2.6	**2.3**	**2.9**
3Q	16205.6	**16499.6**	**16959.2**	2.7	**1.8**	**2.8**
4Q	16294.7	**16621.7**	**17068.8**	2.4	**2.0**	**2.7**

GDP Chained Price Index

	Index 2009 = 100 (SAAR)			% Change From Same Quarter In Prior Year[2]		
	Actual	Forecast[1]		Actual	Forecast	
Quarter	2014	2015	2016	2014	2015	2016
1Q	107.7	108.7	**110.7**	1.4	0.9	**1.8**
2Q	108.3	**109.2**	**111.2**	1.7	**0.8**	**1.9**
3Q	108.6	**109.7**	**111.8**	1.6	**1.0**	**1.9**
4Q	108.7	**110.1**	**112.3**	1.2	**1.3**	**2.0**

Total Industrial Production

	Index 2002 = 100 (SAAR)			% Change From Same Quarter In Prior Year[2]		
	Actual	Forecast[1]		Actual	Forecast	
Quarter	2014	2015	2016	2014	2015	2016
1Q	102.2	105.7	**108.6**	3.2	3.4	**2.7**
2Q	103.7	**106.0**	**109.4**	4.3	**2.2**	**3.2**
3Q	104.7	**106.8**	**110.2**	4.6	**2.0**	**3.2**
4Q	105.9	**107.7**	**111.0**	4.5	**1.7**	**3.1**

Consumer Price Index

	Index 1982-1984 = 100 (SAAR)			% Change From Same Quarter In Prior Year[2]		
	Actual	Forecast[1]		Actual	Forecast	
Quarter	2014	2015	2016	2014	2015	2016
1Q	235.4	235.2	**240.2**	1.4	-0.1	**2.1**
2Q	236.8	**236.5**	**241.6**	2.1	**-0.1**	**2.1**
3Q	237.5	**237.8**	**243.0**	1.8	**0.1**	**2.2**
4Q	237.0	**239.0**	**244.5**	1.2	**0.8**	**2.3**

***See explanatory notes on inside of back cover for details of how this data is compiled.**

BLUE CHIP INTERNATIONAL CONSENSUS FORECASTS

	ANNUAL DATA						END OF YEAR			
	Real Economic Growth % Change GDP		Inflation % Change Consumer Prices		Current Account In Billions Of U.S. Dollars		Exchange Rate [1] Against U.S. $		Interest Rates 3-Month	
CANADA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**1.9**	**2.2**	**1.1**	**2.1**	**-45.4**	**-39.4**	**1.25**	**1.22**	**0.97**	**1.61**
Top 3 Avg.	2.4	2.7	1.6	2.4	-32.5	-29.9	1.32	1.32	1.23	2.20
Bottom 3 Avg.	1.4	1.8	0.6	1.7	-58.2	-50.3	1.17	1.15	0.70	1.05
Last Month Avg.	2.0	2.2	1.1	2.1	-42.5	-76.0	1.24	1.21	0.99	1.55
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.0	2.5	0.9	1.9	-54.6	-39.4	1.25	1.09	0.92	1.22
MEXICO	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**2.7**	**3.3**	**3.2**	**3.6**	**-28.5**	**-30.7**	**15.21**	**14.86**	**3.78**	**4.49**
Top 3 Avg.	3.1	3.8	3.5	4.1	-23.6	-24.6	16.00	15.73	4.20	4.82
Bottom 3 Avg.	2.4	2.9	2.9	3.2	-33.0	-37.4	14.59	14.31	3.37	4.15
Last Month Avg.	2.8	3.4	3.3	3.6	-24.6	-31.4	15.04	14.70	3.60	4.16
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.7	2.1	3.8	4.0	-29.7	-26.5	15.50	12.90	3.30	3.81
JAPAN	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**0.9**	**1.5**	**0.7**	**1.1**	**72.4**	**67.7**	**124.3**	**128.4**	**0.11**	**0.14**
Top 3 Avg.	1.2	1.9	1.1	1.6	110.5	125.9	129.5	136.0	0.16	0.22
Bottom 3 Avg.	0.5	1.0	0.3	0.4	37.1	17.8	120.7	123.5	0.07	0.07
Last Month Avg.	1.0	1.5	0.7	1.1	76.5	67.6	124.7	129.3	0.11	0.14
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.6	-0.1	0.4	2.7	33.6	24.3	124.0	103.0	0.10	0.14
UNITED KINGDOM	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**2.4**	**2.4**	**0.3**	**1.6**	**-118.7**	**-105.6**	**1.49**	**1.50**	**0.66**	**1.43**
Top 3 Avg.	2.7	2.8	0.7	1.9	-79.4	-70.5	1.54	1.56	0.88	1.87
Bottom 3 Avg.	2.1	2.0	0.2	1.5	-141.5	-132.0	1.42	1.44	0.50	1.02
Last Month Avg.	2.5	2.5	0.4	1.6	-127.6	-111.6	1.47	1.49	0.75	1.59
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.7	2.8	2.6	1.5	-119.9	-162.2	1.54	1.67	0.54	0.55
SOUTH KOREA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**3.1**	**3.5**	**0.9**	**1.9**	**95.5**	**86.3**	**1105**	**1108**	**1.89**	**2.35**
Top 3 Avg.	3.5	4.0	1.3	2.5	111.5	100.0	1153	1188	2.08	2.76
Bottom 3 Avg.	2.6	2.9	0.3	1.2	78.8	70.6	1060	1039	1.70	1.95
Last Month Avg.	3.1	3.6	0.9	1.9	97.7	89.3	1099	1096	1.96	2.43
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.9	3.3	1.3	1.3	61.6	84.3	1108	1023	1.73	2.65
GERMANY	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**1.8**	**2.1**	**0.4**	**1.6**	**262.6**	**253.0**	**1.05**	**0.95**	**0.02**	**0.09**
Top 3 Avg.	2.3	2.6	0.6	2.0	287.5	289.4	1.13	1.09	0.07	0.27
Bottom 3 Avg.	1.5	1.6	0.1	1.3	239.5	216.2	0.99	0.65	-0.03	-0.02
Last Month Avg.	2.0	2.0	0.3	1.5	258.9	250.2	1.04	1.03	0.02	0.06
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	0.2	1.6	1.6	0.8	251.3	287.5	1.12	1.40	-0.01	0.31
TAIWAN	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**3.5**	**3.5**	**0.2**	**1.4**	**75.0**	**71.4**	**31.70**	**31.53**	**1.19**	**1.60**
Top 3 Avg.	3.9	4.0	0.7	2.0	84.1	82.2	32.60	32.86	1.59	1.83
Bottom 3 Avg.	3.1	2.9	-0.3	1.1	67.1	64.1	30.86	30.25	0.79	1.37
Last Month Avg.	3.6	3.5	0.3	1.4	70.3	71.4	31.68	31.40	0.98	1.42
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.2	3.7	1.0	1.4	49.6	62.0	30.80	30.07	0.94	0.93
NETHERLANDS	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**1.7**	**1.7**	**0.3**	**1.2**	**93.6**	**71.4**	**1.05**	**0.95**	**0.02**	**0.09**
Top 3 Avg.	2.1	2.0	0.7	1.6	142.9	79.4	1.13	1.09	0.07	0.27
Bottom 3 Avg.	1.5	1.4	0.0	0.8	67.7	60.7	0.99	0.65	-0.03	-0.02
Last Month Avg.	1.7	1.7	0.3	1.1	74.2	72.1	1.04	1.03	0.02	0.06
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	-0.7	0.8	2.6	0.3	73.9	88.9	1.12	1.40	-0.01	0.31

*Best estimates available. **In some cases, actual data for 2014 GDP, consumer prices and current account are not yet available. Where it is unavailable, figures are consensus forecasts from December 10, 2014 Blue Chip Economic Indicators. Figures are currency units per U.S. dollar except for U.K., Australia and the Euro.

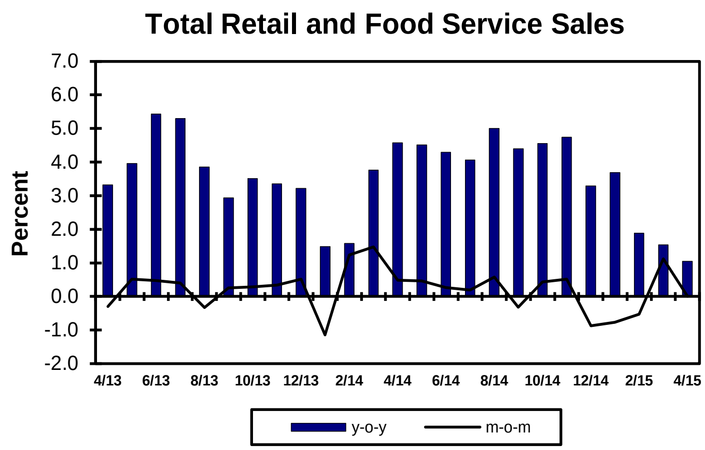
BLUE CHIP INTERNATIONAL CONSENSUS FORECASTS

	ANNUAL DATA						END OF YEAR			
	Real Economic Growth % Change GDP		Inflation % Change Consumer Prices		Current Account In Billions Of U.S. Dollars		Exchange Rate [1] Against U.S. $		Interest Rates 3-Month	
RUSSIA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**-3.6**	**0.2**	**14.8**	**7.0**	**50.3**	**63.4**	**58.8**	**59.1**	**12.90**	**9.22**
Top 3 Avg.	-2.7	1.7	16.4	9.7	71.2	93.2	68.0	66.8	14.70	10.67
Bottom 3 Avg.	-4.8	-1.6	11.9	5.6	28.8	35.5	52.6	51.1	11.11	7.78
Last Month Avg.	-3.9	0.4	14.6	7.1	45.3	53.4	60.6	58.9	12.76	9.23
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.3	0.7	6.8	7.8	34.1	57.4	54.3	35.1	14.10	9.52
FRANCE	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**1.1**	**1.5**	**0.2**	**1.2**	**-23.8**	**-21.2**	**1.05**	**0.95**	**0.02**	**0.09**
Top 3 Avg.	1.4	1.9	0.4	1.6	-9.6	-4.5	1.13	1.09	0.07	0.27
Bottom 3 Avg.	1.0	1.1	0.0	0.8	-42.9	-37.7	0.99	0.65	-0.03	-0.02
Last Month Avg.	1.1	1.5	0.2	1.0	-23.3	-19.9	1.04	1.03	0.02	0.06
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	0.4	0.4	1.0	0.6	-40.2	-29.9	1.12	1.40	-0.01	0.31
BRAZIL	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**-1.0**	**1.1**	**8.0**	**6.0**	**-80.8**	**-75.8**	**3.22**	**3.26**	**11.25**	**10.54**
Top 3 Avg.	-0.2	1.9	8.7	7.1	-73.2	-66.3	3.50	3.60	13.48	12.93
Bottom 3 Avg.	-1.8	0.6	6.8	5.2	-88.4	-86.4	3.06	2.92	9.01	8.14
Last Month Avg.	-0.9	1.2	7.7	5.9	-77.6	-74.1	3.14	3.17	11.06	10.11
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.7	0.2	6.2	6.3	-81.2	-91.3	3.13	2.28	13.80	10.80
HONG KONG	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**2.3**	**2.6**	**3.1**	**2.8**	**7.6**	**8.1**	**7.78**	**7.78**	**0.75**	**1.82**
Top 3 Avg.	2.8	3.2	3.6	3.9	11.2	12.3	7.80	7.80	0.95	2.58
Bottom 3 Avg.	1.8	2.0	2.4	1.9	3.2	2.4	7.75	7.75	0.53	1.17
Last Month Avg.	2.4	2.7	3.1	2.8	7.6	8.6	7.77	7.78	0.79	1.85
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.9	2.3	4.3	4.4	7.4	6.0	7.75	7.75	0.39	0.38
INDIA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**7.4**	**7.7**	**5.4**	**5.6**	**-36.6**	**-48.0**	**63.5**	**63.7**	**7.47**	**7.19**
Top 3 Avg.	7.9	8.5	5.9	6.3	-7.1	-15.5	64.7	65.8	7.81	7.67
Bottom 3 Avg.	6.9	6.9	4.9	5.0	-76.0	-86.0	62.5	61.0	7.18	6.65
Last Month Avg.	7.3	7.6	5.3	5.8	-37.1	-47.6	63.3	63.5	7.52	7.20
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	6.4	7.2	10.7	6.7	-32.4	-29.5	64.0	59.4	7.67	8.53
CHINA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**6.8**	**6.6**	**1.4**	**2.0**	**308.6**	**310.2**	**6.29**	**6.30**	**4.01**	**3.80**
Top 3 Avg.	7.0	7.1	1.7	2.8	388.3	402.3	6.41	6.50	4.67	4.70
Bottom 3 Avg.	6.5	6.2	1.1	1.5	202.7	186.5	6.14	6.07	3.35	2.83
Last Month Avg.	6.9	6.7	1.4	2.0	303.3	302.7	6.32	6.32	3.88	3.88
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	7.7	7.4	2.6	2.1	182.8	209.8	6.20	6.25	2.88	4.84
AUSTRALIA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**2.6**	**2.8**	**1.9**	**2.8**	**-51.0**	**-49.9**	**0.75**	**0.75**	**2.29**	**2.68**
Top 3 Avg.	3.0	3.3	2.4	3.0	-33.2	-26.0	0.80	0.82	2.54	3.27
Bottom 3 Avg.	2.1	2.3	1.5	2.4	-78.4	-81.1	0.70	0.68	2.09	2.03
Last Month Avg.	2.6	2.9	1.9	2.7	-51.2	-49.8	0.75	0.77	2.26	2.83
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.1	2.7	2.4	2.5	-48.3	-51.3	0.78	0.93	2.37	2.74
EUROZONE	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
June Consensus	**1.5**	**1.7**	**0.2**	**1.2**	**316.8**	**316.6**	**1.05**	**0.95**	**0.02**	**0.09**
Top 3 Avg.	1.7	2.3	0.6	1.5	385.1	405.3	1.13	1.09	0.07	0.27
Bottom 3 Avg.	1.4	0.9	-0.2	0.9	250.2	239.3	0.99	0.65	-0.03	-0.02
Last Month Avg.	1.5	1.8	0.0	1.1	326.3	328.2	1.04	1.03	0.02	0.06
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	-0.4	0.9	1.4	0.4	251.3	287.5	1.12	1.40	-0.01	0.31

Contributors to Blue Chip International Survey: IHS Global Insight, US; Barclays, US; Federal Express Corporation, USA; Credit Suisse, US; JP Morgan, US; Economist Intelligence Unit, UK; BMO Capital Markets, Canada; UBS, US; AIG, New York, NY; Oxford Economics, US; Societe Generale, New York, NY; Bank of America-Merrill Lynch, US; Nomura Capital Markets America, US; Morgan Stanley; US; Moody's Capital Markets, US; Eaton, US; Wells Fargo, US; Moody's Analytics, US; Swisse Re, U.S.; Barclays Capital, US; General Motors Corp., US; and Grupo de Economistas y Asociados, Mexico.

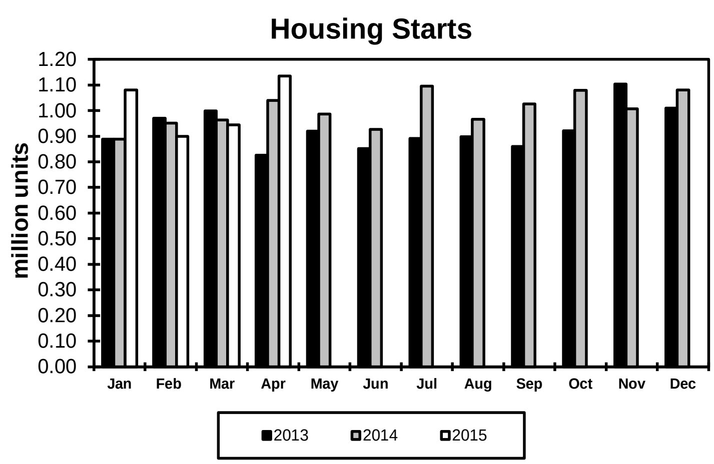
Recent Developments:

Total Retail Sales Were Flat In April But Likely Jumped Strongly In May



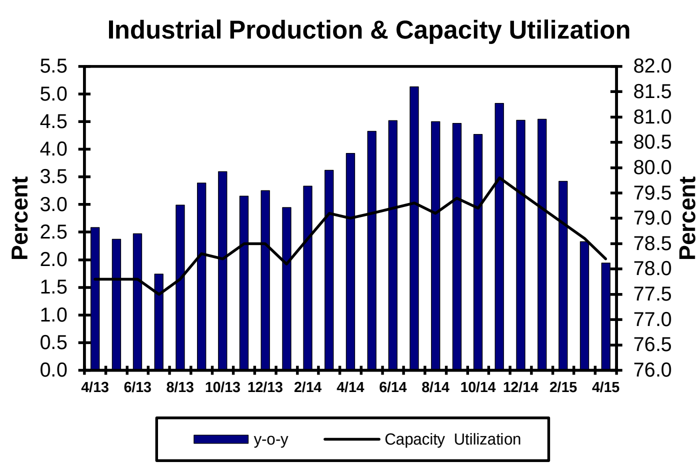
Total retail sales were unchanged in April after an upwardly revised 1.1% jump in March that broke a three-month string of declines. The flat April reading left total retail sales up just 0.9% on a y/y basis. Auto sales fell 0.4% in April and sales excluding autos were up just 0.1%. Core retail sales that exclude autos, gasoline and building materials and go into the calculation of PCE also were unchanged in April and up a soft 2.1% y/y. April sales at furniture stores fell 0.9% and were up 1.5% y/y while sales at apparel stores rose 0.2% in April and up 1.2% y/y. Sales at general merchandise store fell 0.5% in April and were down 1.3% y/y while sales at food stores slipped 0.1% but were up 2.1% y/y. Sales at gasoline stations declined 0.7% in April. They were down 22% y/y, the drop accounted for the sharp decline in prices. Continuing to buck the soft trend in sales, purchases at eating and drinking establishments rose 0.7% in April and were up 8.5% y/y. Total retail sales in May will likely be up sharply, registering an increase of more than 1.0% on the back of the best monthly sales rate for cars and light trucks since 2005. Sales at building material stores also likely popped higher on nicer weather across the nation.

Housing Starts Surged In April



Total housing starts surged a larger-than-expected 20.2% in April to an annual rate of 1.135 million units. Starts of single-family units jumped 16.7% to an annual rate of 733, 000 while starts of multi-family units rose by 27.2% to an annual rate of 389,000. Total starts were up 9.2% y/y in April, with single-family starts higher by 14.7% y/y. By region, starts were up nicely during April in all regions except the South. Total building permits rose 10.1% in April and were up 6.4% y/y. Single-family permits rose 3.7% while permits to building multi-family homes surged 20.5%. New homes sales also were better than expected in April, rising 6.8% following a 10% drop in March. The median price of a new home was up 8.3% from a year ago. The supply of new homes rose 0.5% to 205,000 but the supply of new homes compared to sales declined to 4.8 months. Sales of existing homes fell 3.3% to an annual rate of 5.040 million units. That followed a 6.5% increase in March. Single-family home sales fell 3.7% in April after increasing 5.7% in the prior month. Sales of condo and co-ops were unchanged. The median sales price of an existing single-family home was up 8.9% y/y in April.

Total Industrial Production Fell Again In April



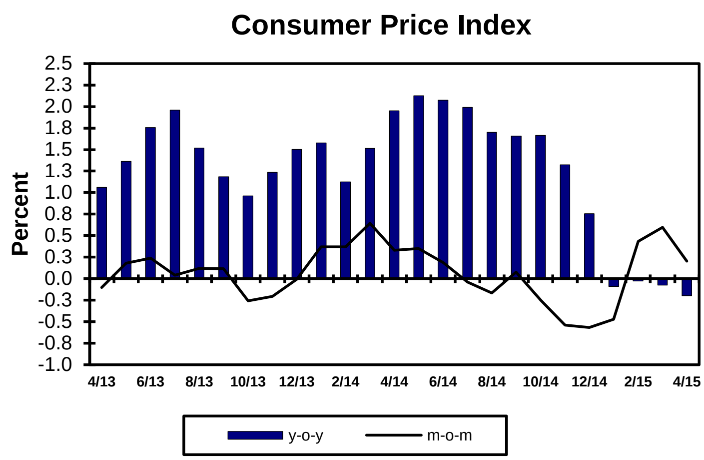
Total industrial production fell for a fifth consecutive month in April, dropping 0.3% after an upwardly revised 0.3% fall in March. The April decline left total production up just 1.9% on a y/y basis. Manufacturing output was unchanged in April and up 2.3% y/y. Mining output fell for a fourth straight month, dropping 0.8% and was up 1.3% y/y, the weakness reflecting weakness in the oil and gas industry where prices have fallen sharply since last summer. Utility output slid 1.3% in April and was up a paltry 0.1% y/y. Durable goods manufacturing increased 0.1% in April, while nondurable goods output fell 0.1%. Motor vehicle and parts output increased 1.3% in April, but was up 6.5% y/y. The total capacity utilization rate fell to 78.2% in April, the lowest since January 2014. Manufacturing's capacity utilization rate slid to 77.2%, the lowest since May 2014. The Institute of Supply Management's May index of activity in the manufacturing sector rose to 52.8 from 51.5 in April. The new orders index strengthened to 55.8 from 53.5, but the production index slipped to 54.5 from 56.0. The export index fell to 50 from 51.5, while the import index firmed to 55 from 54.

Recent Developments:

Trade Deficit Narrowed Sharply In April

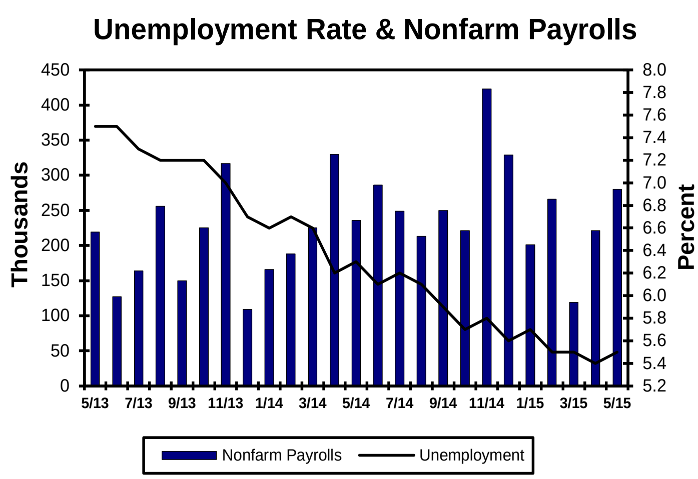
The nominal trade deficit narrowed by a sharper-than-expected 19.2% in April to $40.9 billion from $50.6 billion in March. The sharp turnaround signaled normalization of trade flows that were hampered earlier this year by the West Coast port slowdown. Nominal exports rose 1.0% in April while nominal imports fell 3.3%. The real trade deficit narrowed to $57.2 billion from $66.4 billion in March as real exports increased 2.4% while real imports declined by 3.4%. On a y/y basis, real exports were up 2.3% in April while real imports were up 4.4% y/y. The boom in U.S. energy production helped the trade deficit in petroleum products narrow to just $6.8 billion in April, the smallest since March 2002. Net exports were a huge drag on the economy in Q1, slicing a whopping 1.9 percentage points from real GDP's growth rate. The sharp narrowing of the trade gap in April hints that trade will be a much less significant headwind for GDP growth in the current quarter. However, softer economic growth abroad than in the U.S., coupled with the strength of the U.S. dollar, likely means trade will be a drag on real GDP growth this year and next.

Over the Past Three Months Core CPI Increased At Annual Rate Of 2.6%



The Consumer Price Index (CPI) increased a less-than-expected 0.1% in April, dropping its y/y change to -0.2%. Over the last three months, however, it increased at an annual rate of 2.2%. The core CPI (excludes food and energy prices) increased a larger-than-expected 0.3% in April. That was the largest monthly increase since January 2013 and left the core CPI up 1.8% y/y for a second consecutive month. Moreover, the core CPI rose at an annual rate of 2.6%, its fastest pace since August 2011. Holding down April's increase in the CPI was a 1.3% decline in energy prices as gasoline prices dipped 1.7% and natural gas prices fell 2.6%. Moreover, food prices were unchanged in April. Rent of primary residence and owners' equivalent rent both increased 0.3% in April and were up respectively at annual rates of 3.5% and 2.8% over the past three months. Apparel prices fell 0.3% in April, dropping their y/y change to -0.8%, but medical care prices jumped an outsized 0.7% during the month, lifting the y/y change to 2.9%. The CPI likely increased more in May than in April due to a rebound in energy prices led by gasoline, but the core CPI likely grew by less than in April.

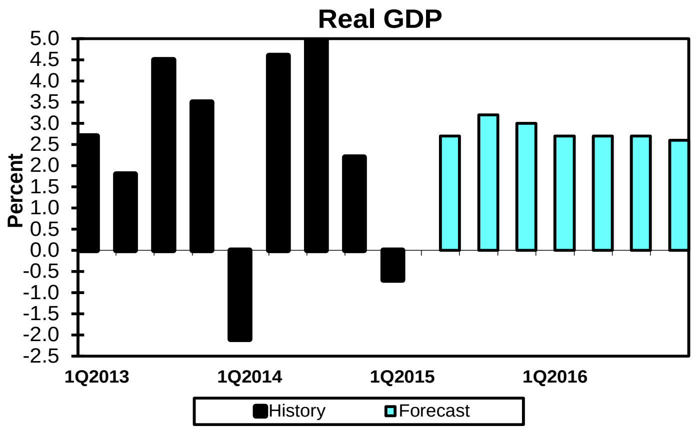
May Growth In Nonfarm Payrolls Beat Expectations



Total nonfarm payrolls grew by a larger-than-expected 280,000 in May and revisions added 32,000 to payroll growth over the prior two months. While job growth in goods producing industries remained modest, gains in private service producing firms accelerated. Manufacturing payrolls rose a modest 7,000 after gains of just 1,000 in April and 6,000 in March. In contrast, payrolls at private service producing firms increased by 256,000 in May, by 185,000 in April and by 137,000 in March. Construction payrolls grew by 17,000 in May, a bit slower than the 35,000 increase in April, but an improvement over the 12,000 decline in March. The average workweek was unchanged in May at 34.5 hours and manufacturing hours worked was unchanged. However, aggregate hours worked increased by 0.3%. Average hourly earnings increased a larger-than-expected 0.3%. That lifted the y/y changed to 2.3%, its highest level since 2009. Household employment increased by a healthy 272,000, but the unemployment rate ticked up by 0.1 of a percentage point due to an increase in the labor force participation rate to 62.9% from 62.8% in April.

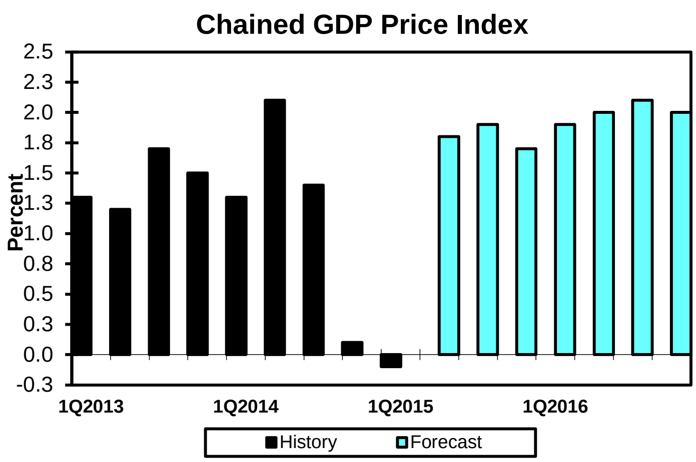
Quarterly U.S. Forecasts:

Real GDP



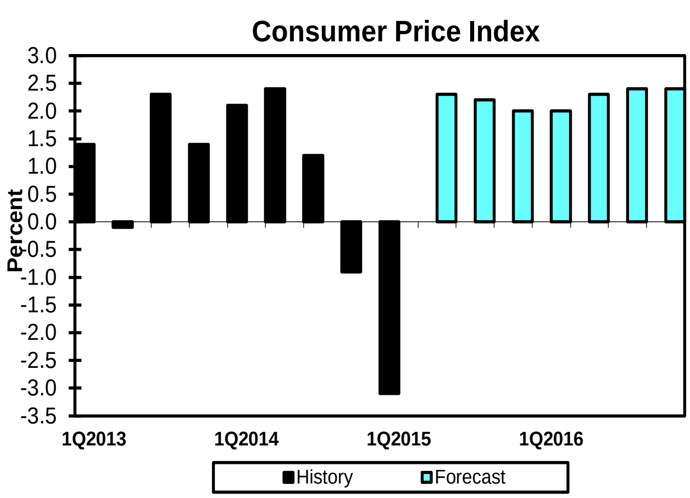
Real GDP contracted 0.7% (q/q, saar) in Q1, according to BEA's second estimate, versus BEA's first estimate of 0.2% growth. The new estimate was actually a bit less than feared, but continued the long-term trend of abnormally soft Q1 growth rates that many suspect results in part from poor seasonal adjustment. The downward revision primarily resulted from a larger-than-previously estimated widening in the net export deficit and a smaller than first estimated contribution to GDP from inventories. Estimated growth in residential investment was revised up and the contraction in business investment was smaller than first thought. Growth is expected to bounce back this quarter but the consensus forecast of real GDP growth in Q2 slipped to 2.7% this month, but the estimate of growth in Q3 rose to 3.2% while the estimate of Q4 growth remained at 3.0%. Due to softer-than-expected growth in Q1, the forecast of y/y growth in 2015 fell to 2.2% while the forecast of q4/q4 growth slipped to 2.0%. Real GDP still is expected to increase 2.8% y/y in 2016 but only 2.7% measured q4/q4.

Chained GDP Price Index



The GDP price index contracted 0.1% (q/q, saar) in Q1, according to BEA's second estimate. That was unchanged from BEA's first estimate. The Q1 softness followed the soft reading of just 0.1% (q/q, saar) in the final quarter of last year. The PCE price index contracted an unrevised 2.0% (q/q, saar) in Q1 after falling 0.4% (saar) in Q4 2014. Prices for consumer goods contracted 8.6% (q/q, saar), knocked lower by a 2.6% decline in the index for durable goods and a 11.6% contraction in prices for nondurable goods. The latter primarily reflected plunging energy prices. The price index for consumer services increased a downwardly revised 1.4% (q/q, saar). The price index for nonresidential investment increased a downwardly revised 0.2% (q/q, saar) versus the original estimate of 0.6%. The price index for exports fell 9.8% (q/q, saar), while the price index for imports plunged 16.6%. In both cases, falling prices for crude oil and related products were big factors. The forecast of 2015's y/y change in the GDP price index stayed at 1.0% this month, but the estimate of its q4/q4 change slid to 1.3%. It still is predicted to increase 1.9% y/y in 2016 and 2.0% q4/q4.

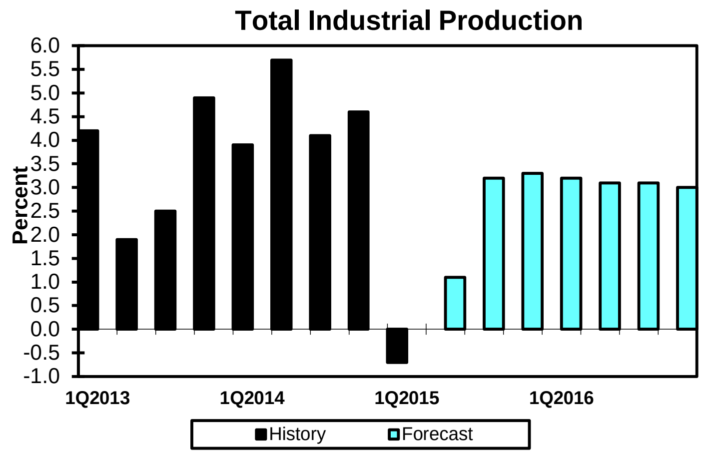
Consumer Price Index



The Consumer Price Index (CPI) contracted 3.1% (q/q, saar) in Q1 after declining 0.9% in Q4 2014. The weakness in both quarters was largely attributable to the plunge in petroleum products since last summer that effectively ended in late January/early February of this year. While the y/y change in the CPI dropped to -0.2% in April and the y/y change in the core CPI remained at 1.8% both registered much livelier increases over recent months. Indeed, the CPI was up 2.2% at an annual rate over the three months ended in April and the core CPI was up 2.6% at an annual rate over that three-month period. Lifting prices over the past three months was a rebound in energy prices, particularly gasoline which increased at a 19.2% annual rate in the three months ending in April. However, rent of primary residence and owners' equivalent rent increased at respective annual rates of 3.7% and 3.2% over the same period. The CPI is forecast to rebound to 2.3% (q/q, saar) in Q2 2015, 2.2% in Q3 and 2.0% in Q4. Consensus forecasts of 2015's y/y and q4/q4 change in the CPI remained this month at 0.2% and 0.8%, respectively. Also unchanged this month were consensus predictions that the CPI would increase 2.2% y/y in 2016 and expand by 2.3% q4/q4..

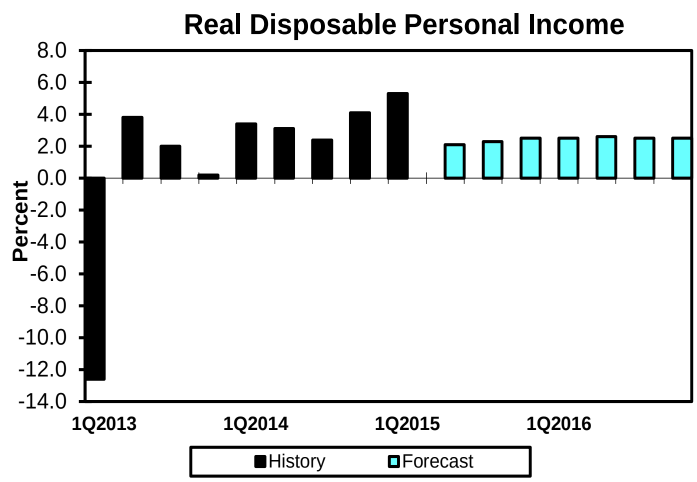
Quarterly U.S. Forecasts:

Industrial Production



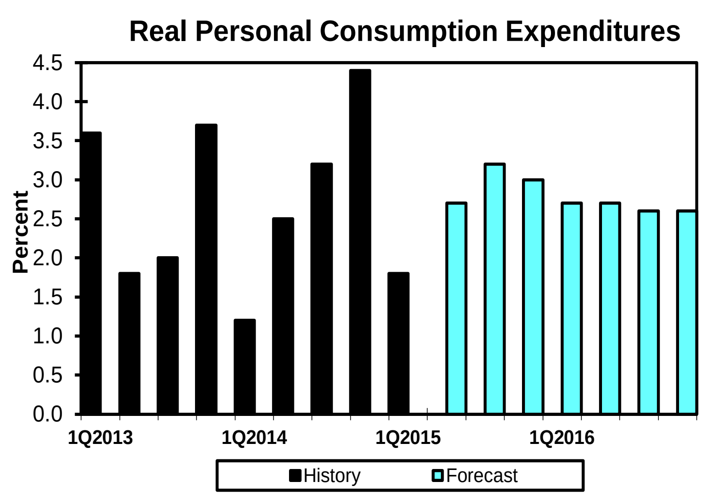
Total industrial production was weak in Q1, contracting an upwardly revised 0.7% (q/q, saar) and leaving it up just 1.7% compared to Q1 2014. Manufacturing output was even softer in Q1, contracting an upwardly revised 1.0% (q/q, saar). While that marked its first significant quarterly decline since 2009 it still was up 3.5% from a year earlier. Motor vehicle and parts production contracted 3.8% (saar) in Q1 after declining 3.1% (saar) in Q4 of last year. That followed a 18.3% (saar) surge in Q3 2014. Mining output contracted a sizable 6.0% (saar) last quarter, after increasing just 1.8% (saar) in Q4. The slowdown in Q1 reflects a more than 60% annual rate of decline in oil and gas well drilling due to plunging prices. Utility output rose a strong 11.1% (saar) in Q1, not far short of its strong 17.8% (saar) performance in Q4 2014. Total industrial production is expected to rebound over the rest of this year, but the forecast of its y/y change in 2015 fell 0.6 of a percentage point this month to 2.5%. The forecast of its y/y change in 2016 remained at 3.1%.

Real Disposable Personal Income



Real disposable personal income (DPI) grew a downwardly revised 5.3% (q/q, saar) in Q1 compared to BEA's initial estimate of 6.2%, but growth in Q4 was revised up to 4.1% from the previous estimate of 3.6%. The Q1 increase still represented the fastest pace since Q4 2012. DPI unadjusted for inflation increased a downwardly revised 3.2% (q/q, saar) in Q1; the larger inflation-adjusted (real) increase due to a large 2.0% (q/q, saar) contraction in the PCE deflator. In unadjusted terms, personal income grew 4.1% (q/q, saar) in Q1, 0.5 of a percentage point less than its upwardly-revised Q4 2014 increase. Unadjusted wages and salaries grew 4.9% (saar) and total employee compensation increased 4.8% (saar) in Q1, both somewhat slower than in the prior quarter. Preventing the Q1 increase in DPI from being even larger, proprietors' income contracted 3.5% (saar) in and personal interest income fell 4.4% (saar). Real personal income minus transfer payments grew 5.3% (saar) in Q1. The consensus predicts real DPI growth will slow this quarter to a more trend-like pace due to a rebound in inflation. The consensus looks for real DPI to register a y/y increase of 3.4% in 2015 and 2.5% in 2016.

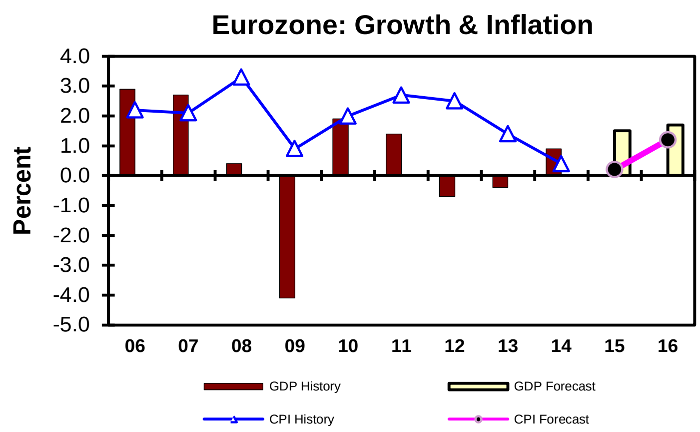
Real Personal Consumption Expenditures



Real personal consumption expenditures (PCE) increased a downwardly revised 1.8% (q/q, saar) in Q1, according to BEA's second estimate, 0.1 of a percentage point less than originally estimated. However, all of the real (inflation-adjusted) growth was accounted for by the 2.0% (q/q, saar) contraction in the PCE price deflator. In nominal terms, PCE actually contracted 0.2% (q/q, saar). Real consumer spending on goods grew just 0.5% (q/q, saar) in Q1 as spending on durable goods increased only 1.1% (q/q, saar) versus 4.8% in Q4. Fewer car and light trucks sales were the primary culprit. Spending on nondurable goods increased 0.1% (q/q, saar) compared to 4.1% in the prior quarter. The Q1 softness here was in part the result of harsh winter weather that hampered consumer spending at malls and restaurants. Consumer spending on services grew 2.5% (q/q, saar) versus 4.3% in Q4. The consensus looks for real PCE growth to average about 3.0% (q/q, saar) over the remaining three quarters of this year. The forecast of this year's y/y increase in real PCE slipped 0.2 of a percentage point to 2.9%. The consensus forecast of 2016's y/y increase in real PCE remained at 2.8% for a fifth consecutive month.

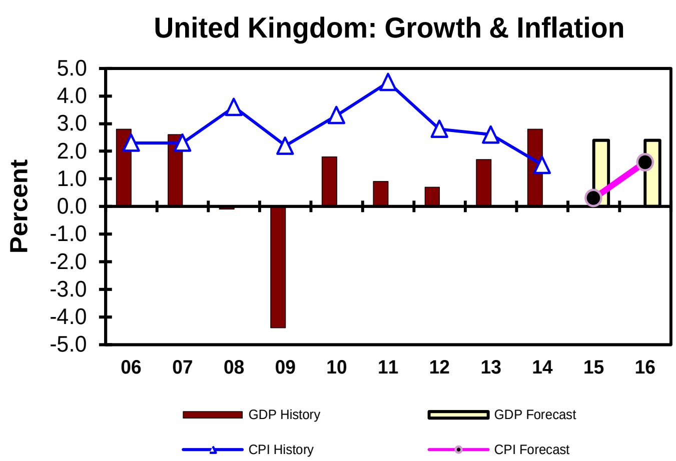
International Forecasts:

Eurozone



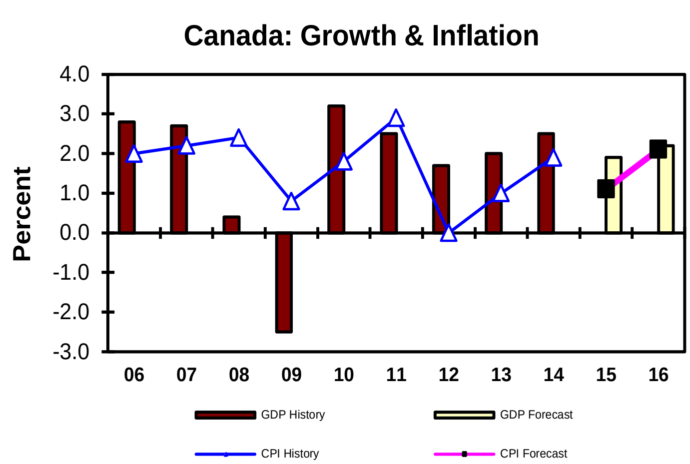
Real GDP in the Eurozone underperformed expectations in Q1, growing 1.6% (q/q,saar) versus 1.3% in the final quarter of last year. Holding down growth, Germany's economy grew just 1.1% (q/q, saar) after registering growth of 2.8% in Q4 2014. In contrast, three of the four other largest economies in the currency zone saw the pace of growth improve. Real GDP in France grew 2.2% versus 0.1% in Q4, Spain's economy grew 3.8% compared to 2.7% in the prior quarter, and Italy's expanded by 1.2%, snapping a multi-quarter string of contractions. Early data, suggest somewhat faster growth for the Eurozone in the current quarter. Moreover, employment and inflation appear to have picked up. In April, the Eurozone unemployment rate fell to 11.1%, the lowest in more than three years, and the core consumer price index jumped 0.3%, lifting its y/y change to 0.9%. Moreover, consumer confidence remained at its highest level since the summer of 2007. The consensus this month still forecast that real GDP would increase 1.5% (y/y) in 2015, but estimated y/y growth in 2016 fell to 1.7%.

United Kingdom



Real GDP in the U.K. grew 1.2% (saar) in Q1, about half its Q4 2014 pace and the softest quarterly reading since Q4 2012. That dropped the y/y growth rate to 2.4% in Q1 from 3.0% Q4 2014. Data indicated that growth in the dominant service sector slowed, while output in the manufacturing and agriculture sectors each suffered small declines. Output in the construction sector contracted steeply and a widening trade deficit was the biggest drag on GDP during the quarter. Adding to the disappointment, early data suggests the pace of GDP growth may not materially improve in the current quarter. May's services PMI suffered its largest drop since August 2011, dropping to 56.5 from 59.5 in April; the lowest level since December. May's manufacturing PMI also was weaker than expected, rising to just 52.0 from a downwardly revised 51.8. Manufacturing continues to be hurt by the strength of the British Pound and soft growth in the Eurozone. In the meantime, the y/y change in consumer price inflation turned slightly negative at 0.1% in April, the first such occurrence since records began in 1960. Consensus forecasts of real GDP growth in 2015 and 2016 both fell 0.1 of a percentage point this month to 2.4%.

Canada



Real GDP contracted a worse than expected 0.6% (q/q, saar) in Q1 of this year and growth in Q4 2014 was revised down to 2.2% from 2.4%. Weighing especially on the economy is the impact on Canada's energy industry of the sharp retreat in oil prices since last summer and soft growth in the U.S., its leading trading partner. Business investment contracted 15.5% (q/q, saar) in Q1, the most since Q1 2009. Non-residential construction fell 19.7% (q/q, saar) and machinery and equipment spending contracted 7.4% (q/q, saar). Support activities for the mining and gas extraction sector plunged a whopping 30%. Growth in personal consumption slowed to just 0.4% (q/q, saar), also the softest reading since Q1 2009. Residential investment eked out growth of 4.0% (q/q, saar), but exports fell 1.1% (q/q, saar), the second consecutive quarterly contraction. Unexpectedly, inventories remained a contributor to GDP in Q1, but will most likely be a drag on GDP over the remainder of the year. The consensus forecast of real GDP growth in 2015 continued to fall this month, dropping to 1.9%. Moreover, further reductions seem likely. The consensus forecast of real GDP growth in 2016 remained at 2.2% this month.

Databank:

2015 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	-0.8	-0.5	1.1	0.0								
Auto & Light Truck Sales (b)	16.57	16.16	17.05	16.46								
Personal Income (a, current $)	0.3	0.4	0.0	0.4								
Personal Consumption (a, current $)	-0.3	0.1	0.5	0.0								
Consumer Credit (e)	3.6	5.5	7.7	7.3								
Consumer Sentiment (U. of Mich.)	98.1	95.4	93.0	95.9	90.7							
Household Employment (c)	759	96	34	192	272							
Non-farm Payroll Employment (c)	201	266	119	221	280							
Unemployment Rate (%)	5.7	5.5	5.5	5.4	5.5							
Average Hourly Earnings (All, cur. $)	24.76	24.78	24.85	24.88	24.96							
Average Workweek (All, hrs.)	34.6	34.6	34.5	34.5	34.5							
Industrial Production (d)	4.5	3.4	2.3	1.9								
Capacity Utilization (%)	79.2	78.9	78.6	78.2								
ISM Manufacturing Index (g)	53.5	52.9	51.5	51.5	52.8							
ISM Non-Manufacturing Index (g)	56.7	56.9	56.5	57.8	55.7							
Housing Starts (b)	1.080	0.900	0.944	1.135								
Housing Permits (b)	1.059	1.098	1.038	1.143								
New Home Sales (1-family, c)	521	538	484	517								
Construction Expenditures (a)	-1.2	0.6	0.5	2.2								
Consumer Price Index (nsa., d)	-0.1	0.0	-0.1	-0.2								
CPI ex. Food and Energy (nsa., d)	1.6	1.7	1.8	1.8								
Producer Price Index (nsa., d)	0.0	-0.6	-0.8	-1.3								
Durable Goods Orders (a)	1.9	-3.5	5.1	-0.5								
Leading Economic Indicators (g)	0.2	-0.2	0.4	0.7								
Balance of Trade & Services (f)	-42.4	-37.2	-50.6	-40.9								
Federal Funds Rate (%)	0.11	0.11	0.11	0.12	0.12							
3-Mo. Treasury Bill Rate (%)	0.03	0.02	0.03	0.02	0.02							
10-Year Treasury Note Yield (%)	1.88	1.98	2.04	1.94	2.20							

2014 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	-1.2	1.2	1.5	0.5	0.5	0.3	0.2	0.6	-0.3	0.4	0.5	-0.9
Auto & Light Truck Sales (b)	15.20	15.33	16.43	15.97	16.67	16.85	16.40	17.44	16.33	16.35	17.09	16.80
Personal Income (a, current $)	0.5	0.6	0.6	0.2	0.3	0.4	0.3	0.4	0.2	0.4	0.5	0.4
Personal Consumption (a, current $)	-0.2	0.4	0.8	0.2	0.3	0.5	0.2	0.6	0.2	0.4	0.4	-0.2
Consumer Credit (e)	5.2	5.9	7.5	9.5	7.3	7.1	8.5	5.0	6.2	5.8	5.3	6.7
Consumer Sentiment (U. of Mich.)	81.2	81.6	80.0	84.1	81.9	82.5	81.8	82.5	84.6	86.9	88.8	93.6
Household Employment (c)	535	95	495	-72	144	379	154	50	156	653	71	111
Non-Farm Payroll Employment (c)	166	188	225	330	236	286	249	213	250	221	423	329
Unemployment Rate (%)	6.6	6.7	6.6	6.2	6.3	6.1	6.2	6.1	5.9	5.7	5.8	5.6
Average Hourly Earnings (All, cur. $)	24.22	24.30	24.34	24.34	24.4	24.46	24.47	24.55	24.55	24.59	24.68	24.62
Average Workweek (All, hrs.)	34.4	34.4	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.6	34.6	34.6
Industrial Production (d)	3.0	3.3	3.6	3.9	4.3	4.5	5.1	4.5	4.5	4.3	4.8	4.5
Capacity Utilization (%)	78.1	78.6	79.1	79.0	79.1	79.2	79.3	79.1	79.4	79.2	79.8	79.5
ISM Manufacturing Index (g)	51.8	54.3	54.4	55.3	55.6	55.7	56.4	58.1	56.1	57.9	57.6	55.1
ISM Non-Manufacturing Index (g)	54.3	52.5	53.7	55.3	56.1	56.3	57.9	58.6	58.1	56.9	58.8	56.5
Housing Starts (b)	0.888	0.951	0.963	1.039	0.986	0.927	1.095	0.966	1.026	1.079	1.007	1.080
Housing Permits (b)	1.002	1.030	1.061	1.074	1.017	1.033	1.041	1.040	1.053	1.120	1.079	1.077
New Home Sales (1-family, c)	446	417	410	410	457	408	403	454	459	472	449	495
Construction Expenditures (a)	-0.4	0.4	0.0	1.4	1.3	-1.6	0.3	0.1	0.6	1.4	-0.6	0.8
Consumer Price Index (sa, d)	1.6	1.1	1.5	2.0	2.1	2.1	2.0	1.7	1.7	1.7	1.3	0.8
CPI ex. Food and Energy (sa, d)	1.6	1.6	1.7	1.8	2.0	1.9	1.9	1.7	1.7	1.8	1.7	1.6
Producer Price Index (nsa., d)	1.3	1.2	1.6	1.8	2.1	1.8	1.9	1.9	1.6	1.5	1.3	0.9
Durable Goods Orders (a)	-1.4	2.6	3.7	0.9	-0.9	2.7	22.5	-18.3	-0.7	0.3	-2.2	-3.7
Leading Economic Indicators (g)	-0.2	0.6	1.0	0.3	0.6	0.6	1.0	0.1	0.6	0.6	0.3	0.5
Balance of Trade & Services (f)	-39.5	-42.8	-43.1	-44.3	-42.1	-42.4	-41.4	-41.3	-43.2	-42.8	-40.0	-45.6
Federal Funds Rate (%)	0.07	0.07	0.08	0.09	0.09	0.10	0.09	0.09	0.09	0.09	0.09	0.12
3-Mo. Treasury Bill Rate (%)	0.04	0.05	0.05	0.03	0.03	0.04	0.03	0.03	0.02	0.02	0.02	0.03
10-Year Treasury Note Yield (%)	2.86	2.71	2.72	2.71	2.56	2.60	2.54	2.42	2.53	2.30	2.33	2.21

(a) month-over-month % change; (b) millions of units, saar; (c) thousands of units, saar; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Special Questions:

1. At which upcoming meeting do you think the FOMC will FIRST HIKE its target for the federal funds rate?

(Percent of those responding)

Jun.16-17 2015	Jul.28-29 2015	Sep.16-17 2015	Oct. 27-28 2015	Dec. 15-16 2015	Jan. 2016 or later
0.0%	1.9%	82.7%	5.8%	7.7%	1.9%

2. The mid-point of the Federal Reserve's current federal funds rate target range is 0.0%-0.25%. The latest median expectations of FOMC members puts the fed funds rate at 0.625% at the end of 2015, 1.875% at the end of 2016, and 3.125% at the end of 2017. What do you think will be the mid-point of the FOMC's fed funds rate target range at the end of 2015, 2016 and 2017?

Mid-point of Federal funds rate target range at end of:

	2015	2016	2017
Consensus	**0.576%**	**1.761%**	**2.878%**
Top 10 Average	0.783%	2.358%	3.613%
Bottom 10 Average	0.333%	1.196%	2.184%

3. Do you believe the Federal Reserve has held its overnight policy rate at the "emergency" level of 0%-0.25% for too long?

(Percent of those responding)

Yes	No
36.0%	64.0%

4. The price index for personal consumption expenditures was up just 0.1% on a y/y basis in April. How much will it increase on a December-over-December basis in 2015 and 2016?

December/December, percent change in PCE Price Index

	2015	2016
Consensus	**1.0%**	**2.0%**
Top 10 Average	1.6%	2.5%
Bottom 10 Average	0.4%	1.7%

5. What is your forecast of the y/y percent change in real residential investment in 2015 and 2016?

Y/Y percent change in real residential investment

	2015	2016
Consensus	**6.6%**	**9.0%**
Top 10 Average	9.9%	14.3%
Bottom 10 Average	4.5%	5.0%

6. What will be the average monthly change in total nonfarm payroll employment during 2015 and 2016?

Average monthly change in Total Nonfarm Payrolls

	2015	2016
Consensus	**219.7 thousand**	**201.0 thousand**
Top 10 Average	247.0 thousand	255.9 thousand
Bottom 10 Average	193.3 thousand	147.2 thousand

7. What will be the per barrel price of crude oil (West Texas Intermediate) at the end of 2015 and 2016?

Price of West Texas Intermediate Crude:

	End of 2015	End of 2016
Consensus	**$60.76 per barrel**	**$68.46 per barrel**
Top 10 Average	$67.35 per barrel	$77.42 per barrel
Bottom 10 Average	$53.43 per barrel	$61.07 per barrel

A Sampling of Views On The Economy Excerpted From Recent Reports Issued By Our Blue Chip Panel Members Or Others

Viewpoints:

After The Pothole

Following the 280k gain in payroll employment in May, the three-month payroll growth trend stands at just over 200k and our preliminary read on the May Current Activity Indicator is 3.0%, similar to the April reading. We view the recent turnaround in the US economic data as further confirmation that weak Q1 GDP growth was largely a result of temporary factors and statistical distortions with little bearing on the outlook for the rest of the year. Once again, the US economy seems to be climbing out of a Q1 pothole.

We continue to expect strong growth for the remainder of 2015. We are currently tracking Q2 GDP growth at 2.7% and expect a slight acceleration to 3% in 2015H2. We expect a pick-up in consumer spending to provide the largest contribution to stronger growth over the remainder of this year. Consumption grew a puzzlingly soft 1.8% in 2015Q1 despite strong disposable income growth and high consumer confidence. While many have expressed concern about softer spending in recent months, it is worth recalling that consumption has risen a respectable 2.7% over the last year. We expect a rebound in coming quarters as the 1 percentage point (pp) increase in the saving rate seen over the last six months reverses.

We also expect a more robust growth contribution from residential investment. Homebuilding also softened in the winter months, but the surge in housing starts in April, the continued easing in mortgage lending standards reported in the Q2 Senior Loan Officer Opinion Survey, and considerable pent-up demand for housing point to stronger growth ahead.

A final reason for confidence in the 2015 growth outlook is that recent data suggest that two major sources of Q1 drag appear to be moderating. First, the Baker Hughes rig count index—a high frequency indicator of capital spending in the energy sector—seems to have finally stabilized after a more than 50% decline over the last half-year. While energy capex will again be a substantial drag on Q2 GDP growth, it appears unlikely to decline much further in the second half of the year. Second, the narrower-than-expected April trade deficit reinforces our confidence that the 1.9pp subtraction from Q1 growth from net exports was an aberration. We expect net trade to boost GDP in Q2 and impose a much more moderate drag thereafter.

We recently reduced our working assumption for the trend rate of measured productivity growth from 2% to 1½%. A ½pp reduction in measured trend productivity growth implies a nearly equal-sized reduction in economy-wide potential GDP growth, which we now view as likely to settle around 1¾%. These revisions are mostly due to changes in the statistical measurement of productivity and do not imply a change in our view of the cycle.

Beyond 2015, we have therefore cut our GDP growth forecast to reflect our lower estimates of productivity growth. To revise our component-level GDP forecasts, we update our macroeconomic model of the US using our new trend productivity growth assumption. The most significant changes are to consumption, which we have revised down from 2½% to 2% by 2018, and to nonresidential investment, which we have revised down from 5% to 3½% by 2018.

We have cut our forecast for aggregate GDP growth by ¼pp to 2½% in 2016H1 and by ½pp to 2¼% in 2016H2 and 2017H1, at which point we expect the labor market to have returned to full employment. We expect growth to remain ¼pp above potential at 2% in 2017H2 and 2018, largely due to a continued boost from homebuilding. Beyond our forecast horizon, we expect the economy to converge to our 1¾% estimate of potential GDP growth.

We have made no changes to the unemployment path as the cut in our forecast for actual growth almost exactly matches the cut in our estimate of potential growth. Could lower (measured) potential growth nonetheless matter for Fed policy? The Summary of Economic Projections (SEP) from the March FOMC meeting showed a central tendency of 2-2.3% for longer-run GDP growth, about 0.25-0.5pp above our estimate of the economy's potential growth rate. While a too-high estimate of potential growth could have dovish implications, we suspect that Fed officials' estimates could prove flexible if actual growth falls short. The FOMC's estimate has already declined considerably.

David Mericle, Goldman Sachs, New York, NY

Life Signs

While GDP remains the standard metric to describe the global business cycle, recent trends have raised some questions about its reliability. Recent volatility has produced wide divergences with other top-down indicators we track—the global PMI and our GDP nowcaster—making it difficult to ascertain near-term global growth momentum. Over lower frequencies, there has been a large and persistent divergence between GDP and the labor market. Global GDP growth over the past three years has averaged close to 2.6% annualized, on par with our estimate of potential growth. By contrast, global employment has accelerated steadily while the unemployment rate has fallen by roughly 1%-pt. Rather than signaling trend-like GDP growth that is holding resource use stable, the message from labor markets is that we are eating up slack at a rapid pace.

We have faded some of the signal from the quarterly gyrations in GDP growth in favor of the signal from our top-down aggregate indicators. At the same time, the lower-frequency signal of slower growth in the face of diminishing slack cannot be ignored and has led us to revise down our estimates of potential growth and the global output gap. We continue to look for the global economy to grow at an above-trend pace in the coming quarters. Regionally, the key moving parts to spark the transition to stronger growth are an expected rebound in US and China. Sectorally, we look for global consumers to wake from their early-year slumber. We also recognize the message from our top-down indicators that business confidence has softened and that an inventory adjustment is underway. These forces should limit the pickup through midyear, particularly in manufacturing.

This week provided constructive news from the May all-industry global PMI, which is signaling 2.9% global real GDP growth. US April and May releases were also encouraging with notable gains in exports and auto sales complemented by a strong employment report.

The notion that global slack is being reduced rapidly is also receiving strong support. Through the first-quarter weakness in global GDP growth, the global unemployment rate edged down to 6.7%, its lowest since late 2008. While we believe there remains ample slack in the global economy overall, there are at least four large economies—the US, the UK, Germany, and Japan—where labor markets are approaching full employment. An important development is clear-cut signs that wages are firming in each of these economies.

In the US, firming wages accompanied by poor productivity is pushing up unit labor costs (ULC), which have increased at a 2.2% annualized pace over the past eight quarters. Against the backdrop of global slack and a rising dollar, we do not believe this will translate into a significant near-term rise in core inflation. However, the Fed will remain highly sensitive to labor market developments. In the near term, the gap between ULC and inflation points to continued downward pressure on corporate profit margins. Should this continue, the risk is that the Fed will need to normalize faster than we expect or that the corporate sector begins to scale back its spending on labor.

Bruce Kasman and David Hensley, J.P. Morgan, New York, NY

Calendar Of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
June 8	**9** NFIB Survey (May) Wholesale Trade (Apr) JOLTS (Apr)	**10** QSS (Q1) Federal Budget (May) EIA Crude Oil Stocks Mortgage Applications	**11** Retail Sales (May) Business Inventories (Apr) Import Prices (May) Weekly Jobless Claims	**12** Producer Price Index (May) Consumer Sentiment (Jun, Preliminary, University of Michigan)
15 NAHB Survey (Jun) Industrial Production (May) Empire State survey (Jun) TIC data (Apr)	**16** **FOMC Meeting** Housing Starts (May)	**17** **FOMC Meeting Statement & Projections (2:00)** **Press Conference (2:30)** EIA Crude Oil Stocks Mortgage Applications	**18** Philadelphia Fed Survey (Jun) Consumer Price Index (May) Current Account (Q1) Weekly Jobless Claims	**19**
22 Existing Home Sales (May)	**23** New Home Sales (May) Durable Goods (May) Richmond Fed Survey (Jun) Markit Services PMI (Jun, Flash) FHFA Home Price Index (Apr)	**24** Real GDP (Q1, Third Estimate) EIA Crude Oil Stocks Mortgage Applications	**25** Personal Income and Consumption (May) Markit Services PMI (Jun, Flash) Kansas City Fed Survey Weekly Jobless Claims Weekly Money Supply	**26** Consumer Sentiment (Jun, Final, University of Michigan
29 Pending Home Sales (May) Dallas Fed Survey (Jun)	**30** Chicago PMI (Jun) S&P/Case-Shiller Home Price Index (Apr) Consumer Confidence (Jun, Conference Board)	**July 1** ADP Employment (Jun) Vehicle Sales (Jun) Markit Manufacturing PMI (Jun, Final) ISM Manufacturing (Jun) Construction Spending (May) EIA Crude Oil Stocks Mortgage Applications	**2** Employment (Jun) Factory Orders (May) Weekly Jobless Claims Weekly Money Supply	**3** **Independence Day Observed** **U.S. Bond and Stock Markets Closed**
6 Markit Services PMI (Jun, Final) ISM Non-Manufacturing (Jun)	**7** International Trade (May) JOLTS (May) Consumer Credit (May)	**8** **FOMC Minutes** EIA Crude Oil Stocks Mortgage Applications	**9** Weekly Jobless Claims Weekly Money Supply	**10** Wholesale Trade (May)
13 Federal Budget (Jun))	**14** Retail Sales (Jun) Business Inventories (May) Import Prices (Jun) NFIB survey (Jun)	**15** Producer Price Index (Jun) Industrial Production (Jun) Empire State Survey (Jul) Beige Book EIA Crude Oil Stocks Mortgage Applications	**16** Philadelphia Fed Survey (Jul) NAHB Survey (Jul) TIC Data (May) Weekly Jobless Claims	**17** Consumer Price Index (Jun) Housing Starts (Jun) Consumer Sentiment ((Jul, Preliminary, Univ. of Michigan)

EXPLANATORY NOTES

For 39 years, ***Blue Chip Economic Indicators***'® monthly survey of leading business economists has provided private and public sector decision-makers timely forecasts of U.S. economic growth, inflation and a host of other critical indicators of business activity. The newsletter utilizes a standardized format that provides a fast read on the prevailing economic outlook. The survey is conducted over two days, typically beginning on the first or second business day of each month. Forecasts of U.S. economic activity are collected from more than 50 leading business economists each month. The newsletter is generally finished on the third day following completion of the survey and delivered to subscribers via e-mail or first class mail.

The hallmark of ***Blue Chip Economic Indicator***® is its *consensus forecasts*. Numerous studies have shown that by averaging the opinions of many experts, the resulting consensus forecasts tend to be more accurate over time than those of any single forecaster.

Annual Forecasts On pages 2 and 3 of the newsletter are individual and consensus forecasts of U.S. economic performance for this year and next. The names of the institutions that contribute forecasts to these pages are listed on the left of the page. They are ranked from top to bottom based on how fast they expect the U.S. economy to expand in the current year. Some of these institutions have one or more asterisks (*) after their names, denoting how many times they have won the annual *Lawrence R. Klein Award for Blue Chip Forecast Accuracy*.

Across the top of pages 2 and 3 is a list of the variables for which the individual cooperators have provided forecasts. Definitions and organizations that issue estimates for these variables are found at the bottom of page 3. For columns 1-9, the forecasts are for the year-over-year percent change in each variable. Columns 10-12 represent average percentage levels of the year in question. Column 15 is an inflation-adjusted dollar level, measured in billions of chained 2009 dollars. High and low forecasts from the panel members for each variable are denoted with an "H" or "L".

Immediately below the forecasts of the individual contributors are this month's consensus forecasts. The consensus is derived by averaging our panel members' forecasts for each variable. Below the consensus forecasts are averages of this month's ten highest and ten lowest forecasts for each variable. Below them are last month's consensus forecasts. To put the forecasts in context, we include four years of historical data for each variable at the bottom of page 2. Please note that these figures can change due to government revisions of previously released estimates. Below the historical data are the number of forecasts changed from a month ago for each variable, the median forecast for each variable and a diffusion index. The diffusion index serves as a leading indicator of future changes in the consensus forecast. A reading above 50% hints of future increases in the consensus; a reading below 50% hints of future declines. The diffusion index is calculated by adding to the number of forecasters who raised their forecasts for a particular variable this month, half the number of those who left their forecasts unchanged, then dividing the sum by the total number of those contributing forecasts.

Historical Annual Consensus Forecasts Page 4 contains the forecasts from previous issues for the current and subsequent year so that subscribers can see how the outlook has changed over time. Each issue also includes graphs and analysis focusing on noteworthy changes and trends in the consensus outlook.

Quarterly Forecasts Page 5 contains quarterly historical data and consensus forecasts of the U.S. economy's performance. For columns 1-7, the forecasts are for the quarter-over-quarter, seasonally-adjusted, annualized percent change in each variable. Columns 8-10 represent average percentage levels for the quarter in question. Columns 11 and 12 represent seasonally-adjusted, annualized levels for the quarter, measured in billions of inflation-adjusted dollars. As is the case on pages 2-3, the consensus quarterly forecasts on the top half of page 5 are simple averages of our contributors' forecasts. The high-10 and low-10 forecasts are averages of the 10 highest and 10 lowest forecasts for each variable. At the bottom of page 5 are additional quarterly consensus forecasts for Real GDP, GDP Price Index, Industrial Production and Consumer Price Index. These figures are derived by taking the annualized quarterly consensus forecasts found on the top of page 5 and computing a quarterly dollar value for Real GDP, and average quarterly index levels for the GDP Price Index, Industrial Production and the Consumer Price Index. We then compute a year-over-year percent change between the relevant quarter and the corresponding quarter of the previous year.

International Forecasts Pages 6-7 contain historical data and consensus forecasts of five key economic variables for 15 of the U.S.'s largest trading partners. A list of the institutions contributing forecasts to these pages can be found at the bottom of page 7. Columns 1 and 2 are forecasts of the year-over-year percent change in inflation-adjusted economic growth and consumer price inflation for this year and next. Column 3 is each nation's estimated current account surplus or deficit, reported in billions of current U.S. dollars. Column 4 is the estimated value of each nation's currency versus the U.S. dollar at the end of this year and next. Column 5 is the estimated level of interest rates on 3-month interest rates in each nation at the end of this year and next. Immediately below this month's consensus and the highest and lowest estimates for each variable are last month's forecasts and a limited amount of historical data. The historical data may change from month-to-month due to government revisions.

Special Questions On page 14, we report on panel members' answers to our special questions. Individuals' responses to the special questions are never displayed, only consensus, top-10 and bottom-10 results. *In March and October, we publish our twice-a-year, long-range survey results*. In addition to our usual forecasts for this year and next, the long-range survey results provide subscribers with consensus forecasts of all the variables found on pages 2 and 3 for the each of the following five years, plus an average for the five-year period after that.

Blue Chip Econometric Detail® With the March, June, September and December issues, subscribers also receive a four-page quarterly supplement entitled *Blue Chip Econometric Detail*®. The supplement contains forecasts of an expanded list of economic and financial variables that are derived from the consensus forecasts found in *Blue Chip Economic Indicators*®. Macroeconomic Advisers, LLC of St. Louis, Missouri produces this forecast detail based on a simulation of its econometric model of the U.S. economy.

*Should you have questions about the contents, or methods used to produce **Blue Chip Economic Indicators**® please contact Randell Moore at randy.moore@wolterskluwer.com or call him at (816) 931-0131.*

CONSENSUS FORECASTS®

Survey Date
April 13, 2015

Every month, Consensus Economics surveys over 250 prominent financial and economic forecasters for their estimates of a range of variables including future growth, inflation, interest rates and exchange rates. More than 20 countries are covered and the reference data, together with analysis and polls on topical issues, is rushed to subscribers by express mail and e-mail.

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Survey Highlights

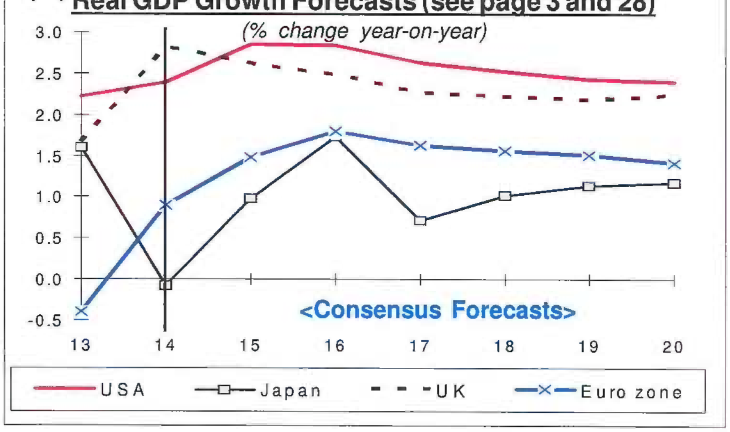
- Growing optimism in the **Euro zone** recovery has seen GDP prospects edge up to 1.5% for the bloc in 2015. Stronger domestic demand is fuelling growth in **Germany** and **Spain**, supported by the continued depression in consumer prices. The **UK** is facing a potential period of uncertainty as the May 7 general election approaches and the race to form the next government looks closer than ever. Meanwhile, the Riksbank announced an unscheduled rate cut on March 18 as **Sweden** battles deflation.

- Declining **US** forecasts appear to underline the economy's below-par end to 2014 and subsequent downbeat mood in Q1 2015. The 2015 industrial production forecast slumped from 3.7% to 3.1% this month, whilst fears remain over the stalling demand for exports, negatively impacted by the strong **US** dollar.

- This month's special survey is our regular compilation of **Long-Term Forecasts** (pages 3, 28, and 29) for the next 5-10 years. Moreover, our **Significant Changes** section (page 2) contrasts long-term aggregate forecasts for 2021-2025 with previous aggregates going back to April 1996, allowing an examination of trends in long-term GDP and inflation expectations.

Our next issue of **Consensus Forecasts** will be available at the end of the day on **May 14, 2015** and will include **Corporate Profits and Real Interest Rates.**

US, Japan, UK and Euro zone Long-Term Real GDP Growth Forecasts (see page 3 and 28)



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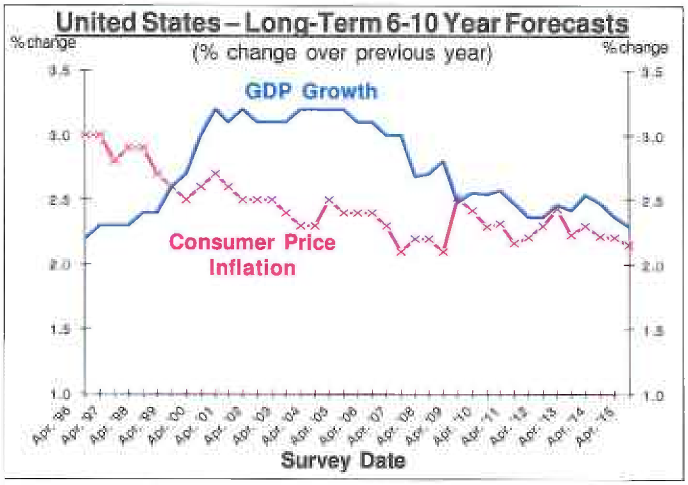
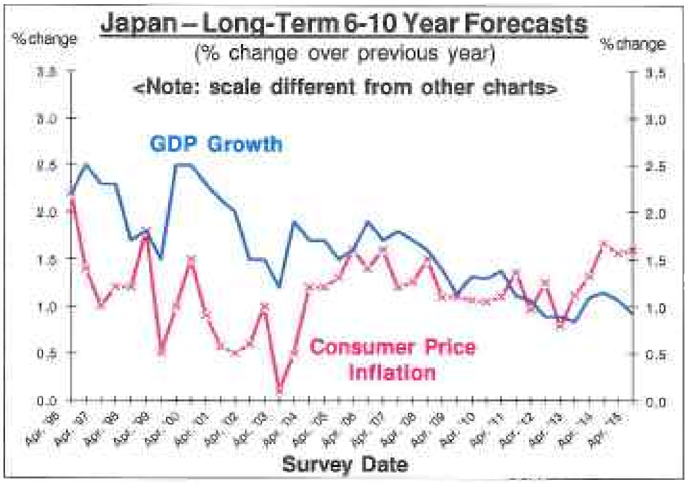
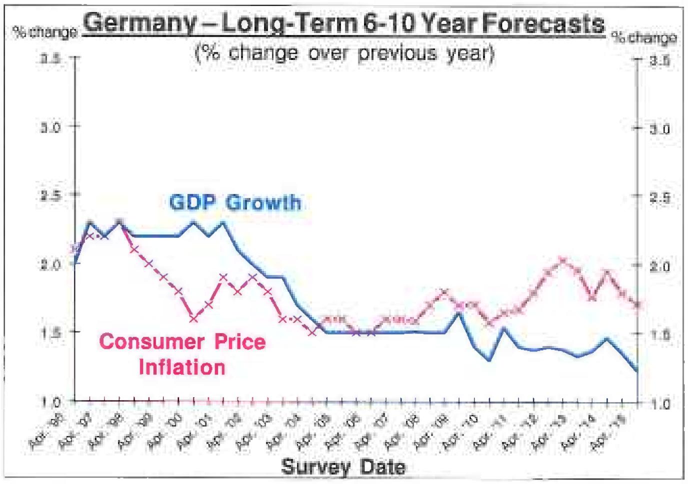
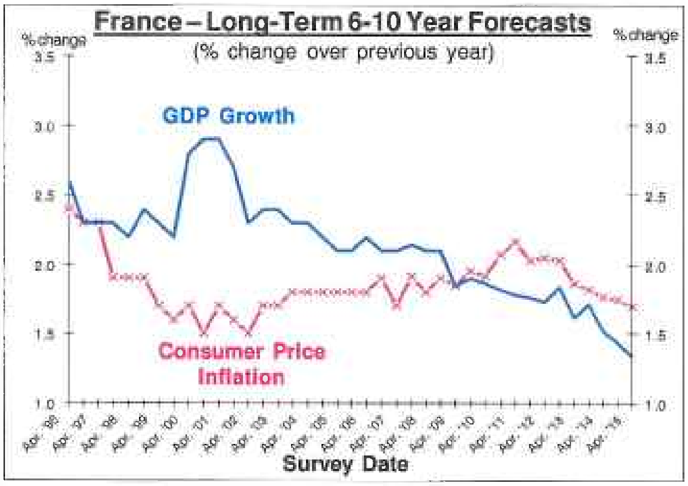
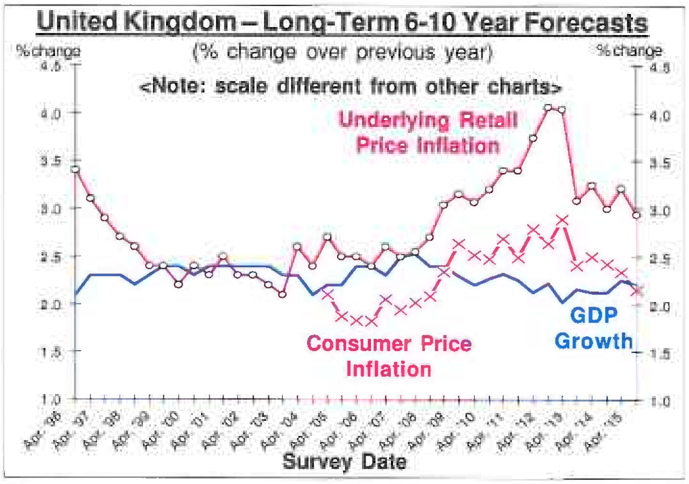
This month, we chart **Significant Changes in Long-Term Forecast Trends for GDP and Inflation** for the **US, Japan, Germany, France,** the **UK, Italy** and **Canada**. Long-term projections for the 6-10 year period average (in this case 2021-2025) are contrasted with those long-term aggregates published all the way back to April 1996. It is this rolling 6-10 year trendline average which we show in the charts below. The 6-10-year trend averages shown in these charts are a measure of changes in potential growth and inflation expectations. This construct has two problems, however. One is that the 6-10 year horizon is a moving target shifting forward one year, each year. The other is that the number of panellists responding to our long-term surveys is smaller and therefore less representative than the numbers responding to our one and two-year surveys on pages 4-24.

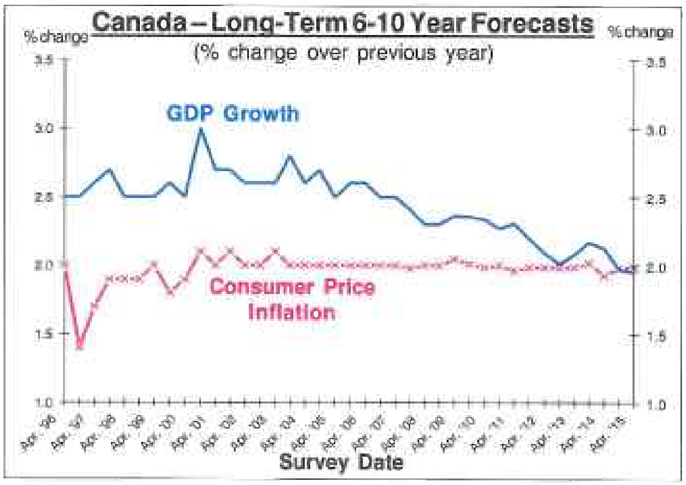












In addition to their regular forecasts, country panellists were asked to provide longer-term forecasts covering the period until 2025 for growth in real GDP, consumer spending, investment and industrial production, along with consumer price inflation, current account balances and long-term bond yields. All definitions correspond to those used in the individual country pages.

United States

* % change over previous year	Historical				Consensus Forecasts						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	1.6	2.3	2.2	2.4	2.9	2.8	2.6	2.5	2.4	2.4	2.3
Personal Consumption*	2.3	1.8	2.4	2.5	3.3	3.0	2.7	2.5	2.4	2.3	2.2
Business Investment*	7.7	7.2	3.0	6.3	4.7	5.0	4.6	4.4	4.1	4.0	3.6
Industrial Production*	3.3	3.8	2.9	4.2	3.1	3.1	3.0	2.7	2.6	2.6	2.5
Consumer Prices*	3.1	2.1	1.5	1.6	0.1	2.2	2.3	2.3	2.3	2.3	2.2
Current Account Balance (USbn)	-459	-461	-400	-411	-404	-459	-529	-566	-556	-571	-567
10 Year Treasury Bond Yield, %[2]	1.9	1.8	3.0	2.2	2.2[3]	2.8[4]	3.9	4.1	4.2	4.3	4.3

[1]Signifies average for period [2]End period [3]End July 2015 [4]End April 2016

As the charts on page 2 (opposite) indicate, the 6-10 year GDP growth potential for the G-7 has trended downward in recent years. Seven years after the global financial crisis precipitated deep recession and an extended period of retrenchment, the long-term outlook for the **G-7 and Western Europe** remains clouded by uncertainty. Although the **United States** and **United Kingdom** appear to be on firmer footing, concerns over long-term trends in public finances, productivity, growth and employment dominate. Consumers and corporations alike are still cautious in their spending decisions. Prior to the Great Recession, the long-term GDP outlook for the **US** hovered around 3%. Our panel has gradually moderated its assessment to 2.3% today, despite growth this year and next expected to reach 2.8%. Some of this pessimism is partly due to demographics: as populations age, there will be less workers to support retirees. Pensions systems are already coming under increasing pressure in many economies. Moreover, with long-term bond yields also falling to low levels, governments are scrambling to finance their commitments. As a result, the shadow of future austerity in many countries, especially **Japan, France**, the **United Kingdom** and **Italy**, looms large. And discontent over those measures, especially at a time of muted growth, is also looming. In **Japan**, a second consumption tax rise planned for October 2015 has been postponed to 2017, precisely because growth faltered after last year's hike. Softer GDP expectations translate into lower job creation and that, too, creates concerns of a brain drain as young people look for work elsewhere. This can precipitate a self-generating spiral into stagnation. However, even with current economic conditions presenting policymakers with acute challenges, productivity gains can lift growth potential (as evidenced by the 1990s), helped by new and as-yet undiscovered technologies. Economists can underestimate technological impact on the long-term outlook. In addition, as the cycle of growth in our panel's forecasts illustrate, even after an extended recession, activity will eventually pick up.

Tables continued on pages 28-29

Japan

* % change over previous year	Historical				Consensus Forecasts						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	-0.4	1.7	1.6	-0.1	1.0	1.7	0.7	1.0	1.1	1.2	0.9
Private Consumption*	0.3	2.3	2.1	-1.2	0.3	1.6	0.0	0.8	1.0	1.0	0.8
Business Investment*	4.1	3.6	0.5	3.8	1.4	3.4	1.9	1.1	1.5	1.5	1.3
Industrial Production*	-2.6	0.2	-0.6	2.1	2.3	3.0	1.3	1.4	1.2	0.8	1.0
Consumer Prices*	-0.3	0.0	0.4	2.7	0.7	1.0	2.0	1.4	1.4	1.5	1.6
Current Account Balance (¥tn)	10.4	4.8	3.9	2.6	13.9	13.5	14.6	11.7	11.3	11.6	7.6
10 Year Treasury Bond Yield, %[2]	1.0	0.8	0.7	0.3	0.4	0.5	0.9	1.2	1.5	1.5	1.9

Germany

* % change over previous year	Historical				Consensus Forecasts						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	3.6	0.4	0.1	1.6	1.9	2.0	1.6	1.4	1.3	1.4	1.2
Private Consumption*	2.3	0.7	0.8	1.2	2.2	1.7	1.3	1.3	1.2	1.2	1.1
Machinery & Eqpt Investment*	6.1	-3.0	-2.4	4.3	2.7	4.5	3.3	2.2	1.7	2.1	1.8
Industrial Production*	7.3	-0.4	0.1	1.5	2.1	2.5	1.7	1.6	1.6	1.6	1.5
Consumer Prices*	2.1	2.0	1.5	0.9	0.4	1.6	1.8	1.9	1.9	1.8	1.7
Current Account Balance (Euro bn)	165	187	182	220	229	229	222	214	207	196	185
10 Year Treasury Bond Yield, %[2]	1.8	1.5	1.9	0.5	0.3[3]	0.6[4]	1.7	2.2	2.5	2.9	3.2

[1]Signifies average for period [2]End period [3]End July 2015 [4]End April 2016

	Average % Change on Previous Calendar Year																Annual Total			
	Gross Domestic Product		Personal Consumption		Business Investment		Pre - Tax Corporate Profits		Industrial Production		Consumer Prices		Producer Prices		Employment Costs		Auto & Light Truck Sales (inc. imports, mn units)		Housing Starts (mn units)	
Economic Forecasters	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
Swiss Re	3.3	3.2	3.4	2.9	6.3	7.0	8.7	5.4	2.8	3.0	-0.1	2.2	-0.5	0.9	na	na	16.7	16.7	1.11	1.33
Econ Intelligence Unit	3.2	2.5	3.1	2.4	na	na	na	na	3.5	3.2	0.5	2.2	0.7	2.3	na	na	na	na	na	na
Citigroup	3.1	3.0	3.5	3.3	4.8	5.9	na	na	4.2	4.0	0.0	2.0	na	na	na	na	na	na	na	na
Moody's Analytics	3.1	3.5	3.6	4.2	4.4	5.9	1.7	10.1	2.3	1.6	0.6	2.6	-0.9	3.9	2.5	2.9	16.9	16.5	1.34	1.88
Bank of America - Merrill	3.1	3.1	3.5	3.2	5.1	4.8	na	na	2.7	3.8	0.2	2.4	na	na	na	na	17.3	18.1	1.15	1.35
PNC Financial Services	3.0	2.9	3.3	2.8	4.2	3.4	na	na	3.2	3.1	0.5	2.4	-1.5	2.2	na	na	17.1	17.3	1.04	1.12
DuPont	3.0	3.4	3.3	3.1	4.2	6.0	-1.0	6.8	3.1	3.7	0.0	2.0	-3.0	2.0	2.5	3.0	17.0	17.3	1.13	1.29
Ford Motor Company	3.0	2.7	3.7	3.2	4.8	3.1	na	na	4.4	2.7	0.2	2.0	-2.3	2.0	na	na	na	na	1.15	1.31
Standard & Poor's	3.0	2.8	3.3	2.9	5.7	5.9	na	na	3.7	3.8	-0.3	1.9	-2.4	2.0	na	na	16.8	16.9	1.20	1.43
Inforum - Univ of Maryland	3.0	2.9	3.2	2.8	5.0	5.1	5.6	5.3	3.3	3.3	0.3	2.2	0.2	1.9	2.3	2.6	16.8	16.9	1.16	1.28
Nat Assn of Home Builders	3.0	3.0	2.9	2.8	5.4	4.6	na	na	3.4	4.3	0.1	2.0	-0.4	2.3	2.5	2.5	16.6	16.6	1.10	1.40
RDQ Economics	2.9	2.9	3.2	3.0	5.0	5.2	6.1	3.9	3.1	3.3	0.1	2.1	na	na	na	na	17.0	17.2	1.10	1.20
Univ of Michigan - RSQE	2.9	3.2	3.2	3.2	4.4	4.1	6.6	5.9	3.7	3.5	0.1	2.0	-1.9	2.8	na	na	16.9	17.2	1.16	1.36
Fannie Mae	2.9	2.8	3.3	2.9	4.3	4.2	1.7	1.3	2.6	2.3	0.2	2.3	-3.2	2.1	na	na	16.8	16.9	1.13	1.32
HSBC	2.9	2.8	3.1	2.8	4.3	5.6	na	na	1.9	2.3	-0.2	1.8	na	na	2.3	2.4	16.8	16.5	1.06	1.12
Credit Suisse	2.9	2.9	3.3	3.2	3.5	4.0	3.6	3.5	4.1	4.3	-0.1	2.0	na	na	na	na	na	na	1.05	1.15
Goldman Sachs	2.8	2.9	3.3	3.5	4.5	5.0	na	na	3.9	3.5	0.3	2.1	na	na	na	na	na	na	1.11	1.32
General Motors	2.8	2.8	3.1	2.8	5.8	4.8	1.3	1.3	3.8	3.2	0.5	2.3	-1.1	1.9	na	na	na	na	1.10	1.35
Georgia State University	2.8	2.6	3.1	2.7	4.9	5.7	10.8	3.0	3.5	3.7	0.0	2.1	-1.6	1.8	2.7	2.9	16.5	16.5	1.13	1.24
Oxford Economics	2.8	2.8	3.1	2.8	4.5	5.1	4.9	2.5	2.9	3.6	0.1	2.3	-3.5	2.1	2.8	3.6	16.8	17.1	1.14	1.38
Wells Capital Mgmt	2.8	2.8	3.3	2.9	5.5	5.5	5.2	3.9	3.4	3.2	0.1	2.0	-2.5	4.2	2.3	2.7	16.9	16.7	1.04	1.00
UBS	2.8	2.8	3.3	2.9	4.4	7.1	na	na	2.7	2.4	-0.1	2.5	na	na	2.7	3.3	na	na	1.25	1.31
IHS Economics	2.8	2.7	3.2	3.1	4.2	6.1	8.0	6.5	1.9	2.9	-0.4	2.1	-4.2	2.1	2.5	2.7	16.9	17.2	1.12	1.31
Nomura	2.7	2.5	3.6	3.0	3.0	4.9	na	na	2.4	2.5	0.2	2.1	-0.4	2.3	3.0	3.5	16.6	16.8	1.05	1.24
Barclays Capital	2.7	2.5	3.2	2.8	5.1	5.1	na	na	2.9	2.5	0.0	2.0	na	na	na	na	na	na	1.03	1.15
American Int'l Group	2.7	2.6	3.3	3.2	5.0	3.6	na	na	3.0	2.0	-0.3	2.0	-3.5	1.9	na	na	16.7	16.9	1.11	1.30
Eaton Corporation	2.6	2.7	3.3	3.0	4.7	4.1	0.5	1.1	3.5	3.4	0.3	2.3	-3.2	2.0	na	na	16.7	17.1	1.14	1.20
Action Economics	2.6	2.7	3.1	3.0	4.7	4.0	2.5	5.5	2.9	3.0	0.0	2.0	0.4	2.2	2.4	2.5	16.8	17.1	1.08	1.20
First Trust Advisors	2.6	2.7	2.9	2.2	5.1	6.4	na	na	3.0	2.0	0.4	2.8	na	na	na	na	17.1	17.3	1.11	1.34
Wells Fargo	2.6	2.9	3.3	2.9	4.8	5.8	4.8	4.2	2.9	3.5	0.2	2.3	-0.3	2.3	2.4	2.7	17.0	17.1	1.13	1.22
Northern Trust	2.6	2.8	3.1	2.8	4.6	4.1	na	na	2.9	3.4	0.1	2.1	na	na	na	na	16.9	17.1	1.17	1.30
JP Morgan	2.5	2.5	3.1	2.8	3.7	4.6	2.3	5.2	2.9	2.7	0.2	2.0	-0.3	2.0	2.7	3.0	16.7	16.8	1.06	1.15
The Conference Board	2.5	2.5	3.0	2.5	4.1	4.5	2.5	1.4	3.3	2.8	0.0	2.1	na	na	na	na	16.7	16.5	1.10	1.32
Consensus (Mean)	2.9	2.8	3.3	3.0	4.7	5.0	4.2	4.3	3.1	3.1	0.1	2.2	-1.6	2.2	2.5	2.9	16.8	17.0	1.12	1.29
Last Month's Mean	3.1	2.9	3.3	2.9	5.2	5.3	5.6	4.4	3.7	3.1	0.3	2.1	-0.9	2.1	2.5	2.9	16.8	17.0	1.16	1.31
3 Months Ago	3.2	2.8	3.2	2.8	5.8	5.4	7.4	3.8	3.8	3.2	0.7	2.2	0.0	2.0	2.6	2.9	16.9	17.0	1.17	1.34
High	3.3	3.5	3.7	4.2	6.3	7.1	10.8	10.1	4.4	4.3	0.6	2.8	0.7	4.2	3.0	3.6	17.3	18.1	1.34	1.88
Low	2.5	2.5	2.9	2.2	3.0	3.1	-1.0	1.1	1.9	1.6	-0.4	1.8	-4.2	0.9	2.3	2.4	16.5	16.5	1.03	1.00
Standard Deviation	0.2	0.3	0.2	0.3	0.7	1.0	3.1	2.4	0.6	0.7	0.2	0.2	1.5	0.7	0.2	0.4	0.2	0.4	0.06	0.15
Comparison Forecasts																				
CBO (Jan. '15)	2.8	3.0									1.1	2.2			2.7	3.0				
OMB (Feb. '15)	3.1	3.0									1.4	1.9								
IMF (Apr. '15)	3.1	3.1	3.5	3.2							0.1	1.5								
OECD (Nov. '14)	3.1	3.0	2.9	2.8	5.8	5.4					1.7									

Government and Background Data

President - Mr. Barack Obama (Democrat). **Congress** - Republicans have a majority with 244 seats in the House of Representatives (lower house) and in the Senate (upper house) with 53 seats. **Next Elections** - November 8, 2016 (Presidential and Congressional). **Nominal GDP** - US$16,768bn (2013). **Population** - 320.1mn (mid-year, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of March 9, 2015

	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4
Gross Domestic Product	2.7	2.4	***3.5***	***3.1***	***2.7***	***2.8***	***2.9***	***2.9***	***2.8***	***2.8***
Personal Consumption	2.7	2.8	***3.3***	***3.5***	***3.4***	***3.1***	***3.1***	***2.9***	***2.8***	***2.7***
Consumer Prices	1.8	1.2	***0.1***	***-0.1***	***0.1***	***0.8***	***1.9***	***2.1***	***2.2***	***2.3***

Percentage Change (year-on-year).

Historical Data

** % change on previous year*

	2011	2012	2013	2014
Gross Domestic Product*	1.6	2.3	2.2	2.4
Personal Consumption*	2.3	1.8	2.4	2.5
Business Investment*	7.7	7.2	3.0	6.3
Pre - Tax Corporate Profits*	4.0	11.4	4.2	-0.8
Industrial Production*	3.3	3.8	2.9	4.2
Consumer Prices*	3.1	2.1	1.5	1.6
Producer Prices*	6.0	1.9	1.2	1.9
Employment Costs*	2.0	1.9	1.9	2.1
Auto & Light Truck Sales (inc. imports), mn	12.7	14.4	15.5	16.4
Housing Starts, mn	0.61	0.78	0.93	1.00
Unemployment Rate, %	8.9	8.1	7.4	6.2
Current Account, US$ bn	-459	-461	-400	-411
Federal Budget Balance, fiscal years, US$ bn	-1300	-1087	-680	-485
3 mth Treasury Bill, % (end yr)	0.0	0.1	0.1	0.0
10 Year Trsy Bond, % (end yr)	1.9	1.8	3.0	2.2

Year Average		Annual Total		Fiscal Years (Oct-Sep)		Rates on Survey Date 0.0%		Rates on Survey Date 2.0%	
Unemployment Rate (%)		Current Account (US$ bn)		Federal Budget Balance (US$ bn)		3 month Treasury Bill Rate (%)		10 Year Treasury Bond Yield (%)	
2015	2016	2015	2016	FY 14-15	FY 15-16	End Jul'15	End Apr'16	End Jul'15	End Apr'16
5.3	4.8	-375	-395	-267	-400	0.2	1.3	2.2	3.2
5.3	5.1	-392	-467	-443	-417	na	na	2.5	3.4
5.3	5.1	-267	-266	-510	-615	0.3	0.8	2.3	2.6
5.4	5.1	-437	-615	-406	-297	0.1	1.3	2.4	3.6
5.3	4.7	-414	-455	-475	-525	0.0	0.7	2.2	2.5
5.3	4.8	na	na	na	na	0.1	0.9	2.2	2.4
5.4	5.0	-400	-400	-450	-425	0.1	1.5	2.5	3.5
5.3	5.2	na	na	-487	-468	na	na	2.0	2.7
5.4	5.3	-351	-341	na	na	0.3	1.5	2.1	3.2
5.4	5.1	na	na	na	na	0.3	1.6	2.5	3.2
5.5	5.3	-492	-523	-488	-454	0.3	1.0	2.2	2.8
5.3	4.5	na	na	-400	na	0.2	1.3	2.4	3.2
5.3	5.0	na	na	na	na	0.3	1.0	2.1	2.6
5.4	5.1	-405	-472	-449	-409	0.3	0.6	2.0	2.2
5.4	5.0	-382	-410	-441	-435	0.0	0.5	2.1	2.6
5.3	4.7	na	na	na	na	na	na	2.3	2.6
5.4	5.0	-512	-693	-450	-575	0.1	0.9	2.4	2.7
5.4	5.0	-415	-540	-400	-420	0.1	1.0	2.4	3.2
5.5	5.3	-436	-440	-484	-360	0.2	1.0	2.0	3.0
5.3	5.0	-372	-345	-435	-433	0.0	0.6	2.1	2.5
5.6	5.4	-375	-425	-450	-435	0.1	1.1	2.1	2.6
5.5	5.1	-343	-448	-475	-500	0.3	1.0	2.0	2.6
5.5	5.2	-345	-390	-513	-392	0.2	1.0	2.2	2.8
5.3	5.0	-400	-420	-469	-536	0.0	1.0	2.2	2.6
5.3	4.6	-497	-537	-425	-375	na	na	1.9	na
5.4	5.1	-403	-517	-429	-447	0.1	1.1	2.3	2.7
5.4	5.2	na	na	na	na	0.1	1.0	2.1	3.1
5.4	5.0	-412	-474	-486	-485	0.3	1.5	2.1	2.6
5.4	4.9	-426	-444	-370	-315	0.4	1.1	2.5	3.4
5.4	5.0	-400	-475	-510	-575	0.1	1.2	2.2	2.5
5.4	5.3	na	na	na	na	0.4	1.8	2.5	3.4
5.3	4.7	-455	-534	-486	-455	na	na	na	na
5.3	4.7	na	na	na	na	0.3	1.0	2.3	2.6
5.4	5.0	-404	-459	-448	-448	0.2	1.1	2.2	2.8
5.4	5.0	-364	-412	-449	-440				
5.4	5.1	-339	-364	-452	-455				
5.6	5.4	-267	-266	-267	-297	0.4	1.8	2.5	3.6
5.3	4.5	-512	-693	-513	-615	0.0	0.5	1.9	2.2
0.1	0.2	53	90	53	78	0.1	0.3	0.2	0.4
5.5	5.4			-486	-455				
5.4	5.1			-583	-474				
5.5	5.1	-410	-455						
6.0		-312	-317						

A Pause in Growth During Q1

The final Q4 national accounts report confirmed that GDP grew by 2.2% (q-o-q annualized), down from the previous quarter's 5% pace. Personal consumption remained the main driver of activity, surging by 4.4% on the back of an annualized 3.6% jump from real disposable income. However, the pace of business investment halved from Q2 and Q3 2014, and pre-tax profits fell by 5.5% (q-o-q annualized) compared with a +12.8% jump in Q3 and 38.3% surge in Q2. The hit from the strong US dollar has likely been affecting export-oriented companies' profit margins, while the oil sector has retrenched in the face of weak oil prices. February and March 2015 releases suggest that activity slowed further, prompting our panel to downgrade its GDP outlook this month. Despite the recent drop in oil prices providing savings at the pump for US consumers, personal consumption expenditure fell by 0.1% (m-o-m) in real terms in February, compared with a 0.2% increase in January. This coincided with a noticeable moderation in real disposable income growth, from January's 0.9% jump to only +0.2%. As in 2014, the Eastern seaboard was once again hit by bitterly cold weather and snowstorms, impacting on both consumer and factory activity.

Industrial production did grow by 0.1% (m-o-m) in February after declines in the previous two months. Factory goods orders, meanwhile, recorded a 0.2% (m-o-m) advance in February. However, this followed a 3.5% contraction in December and 0.7% fall in January. In addition to inclement weather, business activity and supply-chain linkages have also been impacted by the labor dispute at West Coast ports and, not surprisingly, forecasts for investment and production have been scaled back this month.

US Fed Funds Rate – Apr. 13, 2015 = between 0%-0.25%

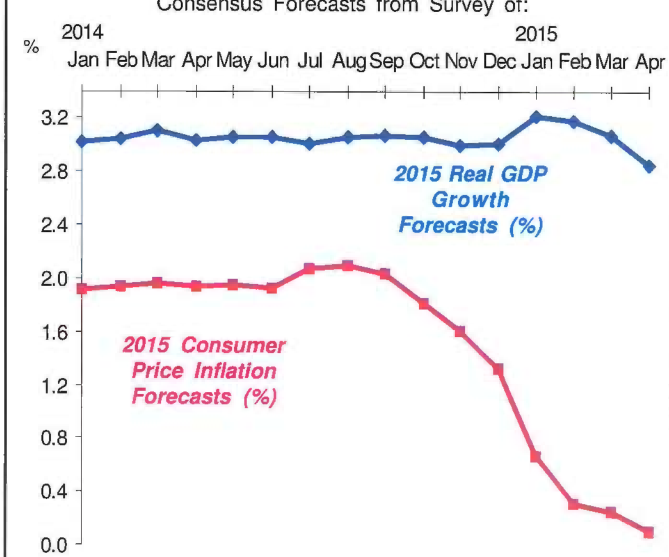
FORECASTS	End Jun. 2015	End Sep. 2015	End Dec. 2015	End Mar. 2016
Consensus Mean Average:	0.151%	0.400%	0.677%	0.935%
Mode (most frequent forecast):	0.125%	0.375%	0.625%	1.000%

Direction of Trade – 2013

Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
Canada	19.0	China	19.6
Mexico	14.3	Canada	14.6
China	7.7	Mexico	12.3
Latin America	*25.9*	*Asia (ex. Japan)*	*28.8*
EU	*16.7*	*Latin America*	*19.3*
Asia (ex. Japan)	*12.3*	*EU*	*17.1*

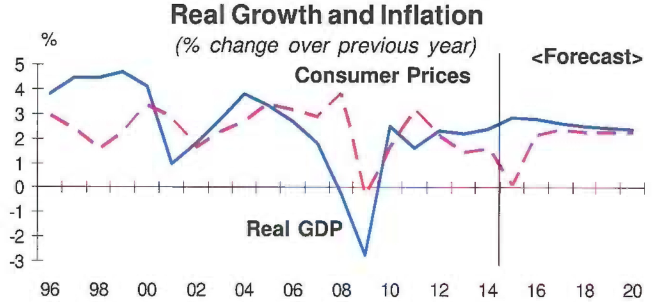
2015 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



Real Growth and Inflation

(% change over previous year)



	Average % Change on Previous Calendar Year														Annual Total			
	Gross Domestic Product 国内総生産		Private Consumption 民間消費		Business Investment 民間設備投資		Industrial Production 鉱工業生産		Consumer Prices 消費者物価		Domestic Corporate Goods Prices 卸売物価		Total Cash Earnings (nominal) 現金給与総額（名目）		New Car Registrations (mn) 新車登録台数（百万台）		Housing Starts (mn) 新設住宅着工（百万戸）	
Economic Forecasters	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
Nippon Steel & Sumikin Rsrch	1.7	3.0	1.2	2.3	4.8	7.4	1.8	2.3	0.4	0.5	-1.3	0.3	1.5	2.7	2.7	2.8	0.89	0.93
Econ Intelligence Unit	1.3	2.0	0.7	1.1	na	na	2.1	2.9	1.0	1.6	-0.5	1.9	na	na	na	na	na	na
Hitachi Research Institute	1.3	1.6	-0.4	0.6	-0.3	2.0	2.8	2.1	1.6	2.0	1.5	2.1	1.2	1.0	na	na	0.93	0.95
Merrill Lynch - Japan	1.3	1.9	0.8	2.4	1.4	2.9	3.5	4.3	0.8	1.4	na	na	na	na	na	na	na	na
Mizuho Research Institute	1.2	2.0	0.4	1.5	1.2	3.2	2.2	3.5	0.4	0.9	-1.6	0.7	1.0	1.3	na	na	0.90	0.95
Nomura Securities	1.2	1.7	0.1	1.6	1.7	4.5	2.7	2.4	0.8	1.2	-1.1	-0.2	1.1	1.6	na	na	na	na
Mizuho Securities	1.2	2.2	0.5	2.0	2.8	6.0	3.4	4.5	0.7	1.5	-0.4	2.0	1.6	3.3	na	na	0.83	0.89
Toyota Motor Corporation	1.2	1.9	0.9	2.2	1.9	3.6	na	na	1.2	0.9	na	na	na	na	na	na	na	na
Bank of Tokyo-Mitsubishi UFJ	1.1	na	0.5	na	1.4	na	2.8	na	0.8	na	-3.2	na	na	na	na	na	na	na
ITOCHU Institute	1.1	1.6	0.0	1.1	3.4	-0.6	3.0	2.2	0.6	1.2	-0.2	0.9	1.4	1.5	2.4	2.7	0.85	0.87
Citigroup Japan	1.0	2.2	0.3	1.7	2.3	4.6	2.8	3.1	0.4	0.9	na	na	na	na	na	na	na	na
Morgan Stanley	1.0	1.9	0.0	1.7	2.0	4.8	3.3	3.9	0.8	1.4	na	na	na	na	na	na	na	na
UBS	1.0	1.6	0.3	1.3	2.3	3.8	1.6	2.4	0.9	1.0	na	na	na	na	na	na	na	na
Mitsubishi Research Institute	0.9	1.4	0.2	1.3	1.0	3.0	1.5	2.9	0.5	1.5	-2.0	1.5	na	na	na	na	0.87	0.91
Deutsche Securities	0.9	1.8	-0.2	1.5	1.1	3.2	3.3	3.2	0.7	0.9	-2.8	0.8	1.2	1.9	na	na	na	na
IHS Economics	0.9	1.4	0.7	1.4	1.6	3.2	2.4	4.5	0.5	1.4	0.4	4.2	na	na	na	na	0.92	0.97
NLI Research Institute	0.9	1.8	0.5	2.0	0.7	3.9	1.1	2.8	0.6	1.1	-1.8	1.4	1.6	1.9	na	na	0.89	0.92
JP Morgan - Japan	0.9	1.5	0.5	1.9	1.5	4.4	2.0	3.9	0.7	1.2	-0.7	0.7	na	na	na	na	na	na
Oxford Economics	0.8	1.8	0.4	2.1	0.1	1.0	1.0	2.4	0.3	0.6	-1.5	1.3	-0.1	-0.8	na	na	0.95	0.97
Dai-Ichi Life Research	0.8	2.0	-0.4	1.9	0.6	4.5	1.6	4.7	0.4	0.7	na	na	na	na	na	na	na	na
HSBC	0.8	1.1	0.2	1.7	0.1	1.8	3.1	3.5	0.6	0.8	-1.6	1.1	1.3	1.6	na	na	na	na
Credit Suisse	0.7	1.0	-0.1	1.0	0.4	1.1	2.4	1.8	0.4	0.5	na	na	na	na	na	na	na	na
Japan Ctr for Econ Research	0.6	1.5	0.2	1.7	0.3	3.4	1.5	1.9	0.6	1.1	-1.0	1.1	0.8	0.9	na	na	0.91	0.94
Goldman Sachs	0.6	1.2	-0.1	0.9	-0.4	2.1	0.5	2.3	0.4	0.8	-0.9	2.5	na	na	na	na	na	na
Mitsubishi UFJ Research	0.5	1.6	0.1	1.7	1.3	2.7	1.6	2.1	0.6	0.5	-1.4	0.2	0.6	0.5	na	na	0.87	0.94
Barclays Capital	0.4	1.6	-0.2	1.3	2.2	4.4	na	na	0.5	0.4	na	na	na	na	na	na	na	na
Consensus (Mean)	1.0	1.7	0.3	1.6	1.4	3.4	2.3	3.0	0.7	1.0	-1.1	1.3	1.1	1.4	2.5	2.7	0.89	0.93
Last Month's Mean	1.1	1.7	0.3	1.5	1.8	3.5	2.4	3.0	0.7	1.1	-1.1	1.2	1.1	1.3	2.6	2.7	0.90	0.93
3 Months Ago	1.2	1.5	0.5	1.3	2.2	3.0	1.7	3.1	1.2	1.2	0.7	1.3	1.1	1.1	2.7	2.8	0.90	0.93
High	1.7	3.0	1.2	2.4	4.8	7.4	3.5	4.7	1.6	2.0	1.5	4.2	1.6	3.3	2.7	2.8	0.95	0.97
Low	0.4	1.0	-0.4	0.6	-0.4	-0.6	0.5	1.8	0.3	0.4	-3.2	-0.2	-0.1	-0.8	2.4	2.7	0.83	0.87
Standard Deviation	0.3	0.4	0.4	0.4	1.2	1.7	0.8	0.9	0.3	0.4	1.1	1.0	0.5	1.0	0.2	0.1	0.03	0.03
Comparison Forecasts																		
IMF (Apr. '15)	1.0	1.2	0.6	2.0					1.0	0.9								
OECD (Nov. '14)	0.8		1.0	1.2					1.8	1.6								

Government and Background Data

Prime Minister - Mr. Shinzo Abe of the Liberal Democratic Party of Japan (LDP) was elected as Prime Minister in December 2014. **Parliament -** President Abe's LDP won 291 of the 475 seats of the Lower House of Parliament and has formed a coalition with the minority party, Komeito Party. **Next Elections** House of Councillors (December 2016). **Nominal GDP -** ¥478.1tn (2013). **Population -** 127.1mn (mid-year, 2013). **Yen/$ Exchange Rate -** 97.51 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***March 9, 2015***

	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4
Gross Domestic Product	-1.4	-0.7	***-1.2***	***1.2***	***2.3***	***2.2***	***2.0***	***1.7***	***1.6***	***1.6***
Private Consumption	-2.9	-2.2	***-3.9***	***1.6***	***1.9***	***1.9***	***1.8***	***1.6***	***1.4***	***1.6***
Consumer Prices	3.3	2.5	***2.3***	***0.1***	***0.1***	***0.5***	***0.9***	***1.1***	***1.2***	***1.3***

Percentage Change (year-on-year).

Historical Data

** % change on previous year*	2011	2012	2013	2014
Gross Domestic Product*	-0.4	1.7	1.6	-0.1
Private Consumption*	0.3	2.3	2.1	-1.2
Business Investment*	4.1	3.6	0.5	3.8
Industrial Production*	-2.6	0.2	-0.6	2.1
Consumer Prices*	-0.3	0.0	0.4	2.7
Domestic Corporate Goods Prices*	1.5	-0.9	1.3	3.2
Total Cash Earnings (nominal)*	-0.2	-0.6	-0.1	0.8
New Car Registrations, mn	2.4	3.0	2.9	2.9
Housing Starts, mn	0.83	0.88	0.98	0.89
Unemployment Rate, %	4.6	4.4	4.0	3.6
Current Account, ¥tn	10.4	4.8	3.9	2.6
General Govt Budget Balance, SNA basis, fisc. years, ¥tn	-41.9	-41.0	-36.7	-31.5 *e*
3 mth TIBOR, % (end yr)	0.3	0.3	0.2	0.2
10 Yr Govt Bond, % (end yr)	1.0	0.8	0.7	0.3

e = consensus estimate based on latest survey

Year Average		Annual Total		Fiscal Years (Apr-Mar)		Rates on Survey Date 0.2%		0.3%	
Unemploy-ment Rate (%)		Current Account (¥tn)		General Government Budget Balance (¥tn)		3 month Yen TIBOR Rate(%)		10 Year Govt Bond Yield (%)	
失業率		経常収支		一般政府 財政収支 (SNA ベース、兆円)		3ヵ月物 円建 譲渡性預金		10年物 国債利回り	
2015	2016	2015	2016	FY 15-16	FY 16-17	End Jul'15	End Apr'16	End Jul'15	End Apr'16
3.2	2.6	15.9	23.1	na	na	0.2	0.2	0.4	0.7
3.5	3.3	na	na	na	na	na	na	na	na
3.4	3.3	9.3	11.5	na	na	0.2	0.4	0.4	0.6
3.5	3.3	11.2	11.5	na	na	na	na	0.2	0.2
3.4	3.3	14.6	13.6	na	na	0.2	0.2	0.5	0.6
3.4	3.3	18.6	18.8	na	na	na	na	0.5	0.9
3.5	3.3	13.4	14.0	na	na	na	na	0.4	0.7
3.4	3.3	na	na	na	na	na	na	na	na
na	na	15.1	na	na	na	0.2	na	0.6	na
3.5	3.3	9.5	10.5	-28.0	-27.3	0.2	0.2	0.4	0.6
3.4	3.2	14.7	15.8	-33.0	-31.8	0.1	0.1	0.4	0.5
3.1	2.8	na	na	na	na	na	na	na	na
3.3	3.2	3.6	4.6	na	na	na	na	na	na
3.5	3.4	17.0	16.9	na	na	na	na	0.5	0.7
3.4	3.3	17.3	17.1	-25.5	-21.4	na	na	na	na
3.6	3.5	na	na	na	na	0.3	0.3	0.5	0.7
3.5	3.3	16.2	14.7	-36.4	-35.3	0.2	0.2	0.4	0.6
3.5	3.3	19.1	19.6	na	na	na	na	0.3	0.4
3.5	3.6	7.2	4.8	-33.8	-29.9	0.1	0.1	0.2	0.2
3.4	3.3	16.0	15.5	na	na	0.2	0.2	0.5	0.7
3.3	3.2	13.3	3.7	-26.0	-23.6	0.1	0.1	0.3	0.4
3.5	3.0	14.8	10.3	na	na	0.2	0.2	0.3	0.3
3.5	3.4	19.5	16.9	-22.1	-16.8	na	na	0.4	0.5
3.4	3.4	11.0	12.4	na	na	na	na	na	na
3.5	3.4	13.9	13.9	-28.6	-26.2	0.2	0.2	0.4	0.6
3.4	3.3	13.9	15.1	na	na	na	na	na	na
3.4	3.3	13.9	13.5	-29.2	-26.5	0.2	0.2	0.4	0.5
3.4	3.3	14.3	14.2	-29.3	-26.7				
3.5	3.4	7.9	8.2	-31.0	-29.3				
3.6	3.6	19.5	23.1	-22.1	-16.8	0.3	0.4	0.6	0.9
3.1	2.6	3.6	3.7	-36.4	-35.3	0.1	0.1	0.2	0.2
0.1	0.2	3.9	4.9	4.8	5.9	0.1	0.1	0.1	0.2
3.7	3.7								
3.5	3.5								

Disappointing Growth Prospects

The GDP outlook has worsened following a spate of disappointing data. Activity was already muted going into 2015, but February production data might even hint at another possible recession in Q1 2015. Industry contracted by -3.4% (m-o-m) in February, its first decline in three months and partly as payback for January's 3.7% surge. Still, this was much larger than expected and highlights the sluggish nature of domestic and external demand. A depreciating yen is translating into cheaper exports – and indeed the economy ran an eighth straight monthly trade surplus in February. This swelled the current account to ¥+1.44tn, its largest surplus in three-and-a-half years. However, this reflects the weak oil price effect rather than resurgent export demand. Moreover, the weaker yen has lifted import costs, eroding consumers' purchasing power. Abenomics helped to boost consumption in 2012 and 2013, but ever since the April 2014 VAT hike, household spending has returned to muted levels. Retail sales recorded a weak -1.9% (m-o-m) showing in January before rising by 0.7% in February. Core real spending, meanwhile, remains in contractionary territory m-o-m and y-o-y. The hope is that better wage prospects, as well as lower inflation, will encourage consumers. Inflation, though, presents its own problems, with the headline CPI continuing to fall by 0.2% (m-o-m) in February.

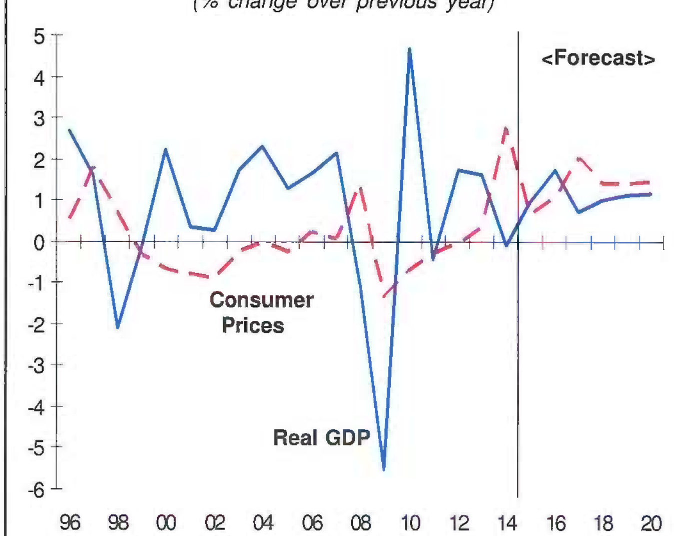
The Bank of Japan's Tankan survey showed sentiment worsening amongst large and small manufacturers and non-manufacturers alike. Small non-manufacturers were especially pessimistic in their assessment of conditions for the next three months. Capex and profit projections for FY2015 have been hindered by weaker demand at home and in China.

Direction of Trade – 2013

Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
United States	18.8	China	21.7
China	18.1	United States	8.6
South Korea	7.9	Australia	6.1
Asia (inc. the above)	*32.4*	*Asia (inc. the above)*	*36.1*
EU	*10.0*	*Middle East*	*19.3*
Latin America	*4.8*	*EU*	*9.4*

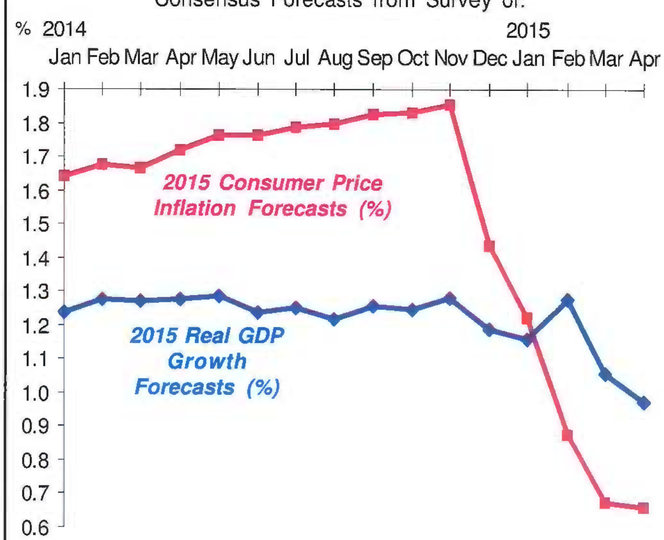
Real Growth and Inflation

(% change over previous year)



2015 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



	Average % Change on Previous Calendar Year													
	Gross Domestic Product		Private Consumption		Machinery & Equipment Investment		Industrial Production		Consumer Prices		Producer Prices		Negotiated Wages and Salaries	
	Bruttoinlands-produkt		*Privater Verbrauch*		*Ausrüstungs-investitionen*		*Produktion im Produzierenden Gewerbe*		*Preisindex für die Lebenshaltung*		*Index für Erzeugerpreise*		*Tariflohn- und -gehaltsniveau*	
Economic Forecasters	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**
Kiel Economics	2.5	3.8	2.2	3.2	3.2	4.8	na	na	0.7	1.1	na	na	2.9	na
Bank Julius Baer	2.4	2.1	3.0	2.0	2.4	2.7	1.8	2.5	0.4	1.7	-0.2	1.5	3.0	3.0
Oxford Economics	2.4	2.1	2.7	1.7	1.6	3.8	1.9	2.0	0.4	1.9	-1.9	1.8	3.1	3.6
IHS Economics	2.3	2.3	3.0	2.3	5.9	7.8	3.1	2.6	0.6	1.9	-0.6	1.6	2.9	3.0
DekaBank	2.2	2.0	2.4	1.3	2.8	6.5	2.0	4.2	0.6	1.7	-0.7	2.0	2.7	3.0
Allianz	2.1	1.7	2.7	1.3	3.1	3.4	2.4	2.4	0.5	1.5	-0.8	1.9	2.8	2.8
RWI Essen	2.1	1.9	2.6	1.7	3.6	5.6	na	na	0.4	1.5	na	na	3.2	2.8
UBS	2.1	2.4	2.1	1.9	2.9	5.1	2.2	3.8	0.3	1.4	0.2	1.8	na	na
Citigroup	2.1	2.2	2.4	2.1	2.1	3.1	2.2	1.9	0.7	2.1	na	na	na	na
Morgan Stanley	2.1	2.5	2.8	2.0	3.2	7.0	na	na	0.6	2.1	na	na	na	na
IWH Halle Institute	2.0	1.6	2.3	1.6	3.0	4.0	2.5	2.0	0.3	1.2	na	na	3.1	2.7
BayernLB	2.0	1.9	2.1	1.3	2.8	4.7	2.9	2.8	0.5	1.7	-1.1	2.4	3.2	2.8
MM Warburg	2.0	1.8	2.1	1.7	3.5	4.2	2.4	1.8	0.3	1.2	-0.8	1.5	2.8	2.8
UniCredit	2.0	2.1	2.3	1.8	1.7	3.7	2.0	2.0	0.0	1.7	na	na	3.2	2.5
WGZ Bank	2.0	1.9	2.3	2.0	2.9	4.0	1.5	2.5	0.5	1.4	-1.0	1.0	2.8	3.0
Deutsche Bank	2.0	1.7	2.3	1.0	3.9	3.5	1.7	2.1	0.0	1.5	-0.7	2.0	2.9	2.9
HWWI	1.9	1.7	1.6	1.2	4.8	4.7	2.1	2.6	0.7	0.6	-0.7	1.8	2.7	2.6
IfW - Kiel Institute	1.8	2.0	2.7	2.2	4.3	9.5	na	na	0.1	1.5	na	na	3.3	2.9
Feri EuroRating	1.8	1.7	1.9	1.1	2.9	3.7	2.2	1.9	0.3	1.6	-0.7	2.2	2.9	2.9
DZ Bank	1.8	1.6	1.8	1.4	0.8	3.5	1.8	3.0	0.4	1.6	-0.1	2.7	na	na
Commerzbank	1.8	1.8	2.3	1.8	3.2	4.8	2.0	2.5	0.5	2.4	-0.7	2.1	4.0	3.7
Helaba Frankfurt	1.8	1.7	1.7	1.5	2.0	4.0	1.7	1.7	0.5	1.6	-0.5	1.5	3.0	3.0
HSBC Trinkaus	1.8	1.8	1.8	1.3	1.6	4.3	2.9	4.1	0.4	1.5	-1.6	1.0	2.8	2.8
Sal Oppenheim	1.8	1.6	2.0	1.7	0.2	3.7	na	na	0.4	1.6	na	na	na	na
Econ Intelligence Unit	1.8	1.7	1.7	0.9	na	na	1.8	1.8	-0.2	1.0	-0.8	1.2	na	na
Goldman Sachs	1.7	1.9	2.2	2.2	1.2	3.4	2.4	2.8	0.3	2.3	na	na	na	na
Berliner Sparkasse	1.7	1.6	1.8	1.1	2.3	3.6	1.6	1.9	0.1	1.8	-1.1	1.7	3.0	2.8
Bank of America - Merrill	1.6	1.8	2.3	1.9	na	na	1.7	1.9	0.1	1.4	na	na	na	na
BHF-Bank	1.6	2.0	1.4	1.2	2.1	3.2	1.5	2.0	0.3	1.5	na	na	2.8	2.8
IFO - Munich Institute	1.5	na	1.7	na	2.6	na	na	na	0.8	na	na	na	na	na
DIW - Berlin	1.4	1.7	1.7	1.5	2.0	4.7	na	na	0.7	1.4	na	na	na	na
Consensus (Mean)	1.9	2.0	2.2	1.7	2.7	4.5	2.1	2.5	0.4	1.6	-0.8	1.8	3.0	2.9
Last Month's Mean	1.8	1.9	2.1	1.6	2.6	4.6	2.1	2.4	0.4	1.6	-0.6	1.7	3.0	3.0
3 Months Ago	1.4	1.8	1.6	1.5	1.8	4.2	1.6	2.4	0.7	1.6	0.1	1.6	3.0	2.9
High	2.5	3.8	3.0	3.2	5.9	9.5	3.1	4.2	0.8	2.4	0.2	2.7	4.0	3.7
Low	1.4	1.6	1.4	0.9	0.2	2.7	1.5	1.7	-0.2	0.6	-1.9	1.0	2.7	2.5
Standard Deviation	0.3	0.4	0.4	0.5	1.2	1.5	0.4	0.7	0.2	0.4	0.5	0.4	0.3	0.3
Comparison Forecasts														
Bundesbank (Dec. '14)	1.0	1.6	1.3	1.3										
Government (Oct. '14)	1.3													
Eur Commission (Jan. '15)	1.5	2.0	2.0	2.0										
IMF (Apr. '15)	1.6	1.7	2.0	1.5					0.2	1.3				
OECD (Nov. '14)	1.1	1.8	1.3	1.7					1.8					

Government and Background Data

Chancellor - Mrs. Angela Merkel (Christian Democratic Party or CDU). **Parliament -** After winning 255 seats in the 622-seat Bundestag (lower house), the CDU have formed a coalition government with the Social Democrats (SPD). **Next Elections -** 2017 (Bundestag). **Nominal GDP -** Euro 2,742bn (2013). **Population -** 82.7mn (mid-year 2013). **$/Euro Exchange Rate -** 1.328 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***March 9, 2015***

	2014		2015				2016			
	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Gross Domestic Product	1.2	1.5	***1.1***	***1.6***	***2.1***	***2.0***	***1.8***	***1.9***	***1.7***	***1.6***
Private Consumption	1.1	2.1	***2.0***	***2.3***	***2.0***	***1.8***	***1.5***	***1.4***	***1.3***	***1.1***
Consumer Prices	0.8	0.5	***0.0***	***0.2***	***0.3***	***0.9***	***1.6***	***1.6***	***1.7***	***1.7***

Percentage Change (year-on-year)

Historical Data

** % change on previous year*	2011	2012	2013	2014
Gross Domestic Product*	3.6	0.4	0.1	1.6
Private Consumption*	2.3	0.7	0.8	1.2
Machinery & Eqpt Investment*	6.1	-3.0	-2.4	4.3
Industrial Production*	7.3	-0.4	0.1	1.5
Consumer Prices*	2.1	2.0	1.5	0.9
Producer Prices*	5.3	1.6	-0.1	-1.0
Negotiated Wages & Salaries*	1.6	3.1	3.1	2.9
Unemployment Rate, %	7.0	6.8	6.9	6.7
Current Account, Euro bn	165	187	182	220
General Govt. Budget Balance (Maastricht definition), Euro bn	-23.3	2.6	4.2	18.0
3 mth Euro, % (end yr)	1.4	0.2	0.3	0.1
10 Yr German Govt Bond, % (end yr)	1.8	1.5	1.9	0.5

Year Average		Annual Total				Rates on Survey Date			
						0.0%		0.2%	
Unemploy-ment Rate (%)		Current Account (Euro bn)		General Govt Budget Bal (Maastricht) (Euro bn)		3 month Euro Rate (%)		10 Year German Govt Bond Yield (%)	
Arbeitslosen-quote, % der Erwerbspers. insgesamt		*Leistungs-bilanz (€ bn)*		*Finanzierungs-saldo des Staates (Maastricht) (€ bn)*		*3 Monate Euro (%)*		*Rendite von Bundesan-leihen, 10 Jahre (%)*	
2015	2016	2015	2016	2015	2016	End Jul'15	End Apr'16	End Jul'15	End Apr'16
6.2	5.1	193	194	26.9	51.9	0.1	0.4	0.2	0.6
6.4	6.2	na	na	na	na	0.0	0.0	0.2	0.6
6.6	6.6	245	234	30.7	30.1	0.0	0.0	0.1	0.1
6.3	6.1	241	246	8.6	12.0	0.1	0.1	0.6	1.5
6.4	6.4	234	245	6.0	6.2	0.0	0.0	0.2	0.5
6.4	6.4	218	212	20.1	16.7	0.1	0.2	0.2	0.6
6.4	6.2	249	259	16.0	16.0	0.0	0.0	0.3	0.3
6.5	6.4	na	na	na	na	0.1	0.1	0.7	1.4
6.3	6.1	223	184	9.6	7.2	0.1	0.1	-0.1	0.3
6.4	6.0	222	220	23.5	21.6	na	na	na	na
6.5	6.4	235	241	16.1	15.3	0.1	0.1	0.4	0.4
6.5	6.5	225	230	2.0	0.0	0.0	0.0	0.1	0.1
6.4	6.2	228	238	15.0	5.0	0.0	0.0	0.1	0.2
6.7	6.6	197	191	9.0	9.0	na	na	na	na
6.4	6.3	230	230	na	na	0.0	0.0	0.3	0.6
6.5	6.6	250	255	19.0	22.0	-0.1	-0.1	0.3	0.5
6.5	6.4	225	220	5.0	10.0	0.0	0.0	0.4	0.7
6.4	6.2	248	251	10.4	8.6	na	na	0.3	0.6
6.3	6.1	227	222	9.8	7.6	0.0	0.1	0.3	0.8
6.4	6.2	250	250	6.0	11.0	0.0	0.0	0.1	0.3
6.4	6.2	250	238	14.0	15.5	0.0	0.0	0.3	0.5
6.4	6.1	225	230	10.0	9.0	0.1	0.1	0.5	0.7
6.5	6.3	206	200	5.0	5.0	0.1	0.1	0.3	0.7
6.4	6.2	na	na	na	na	0.0	0.0	0.3	1.0
na	na	240	246	na	na	na	na	na	na
na	na	na	na	na	na	na	na	na	na
6.4	6.3	227	236	6.0	9.0	na	na	na	na
na	na	203	195	9.8	5.9	na	na	na	na
6.4	6.2	220	245	0.0	0.0	0.0	0.0	0.1	0.5
6.6	na	222	na	3.6	na	0.0	0.0	0.2	0.2
6.8	6.4	240	250	4.2	12.2	na	na	na	na
6.4	6.2	229	229	11.4	12.8	0.0	0.0	0.3	0.6
6.5	6.3	225	224	9.7	12.2				
6.6	6.4	221	220	3.7	5.6				
6.8	6.6	250	259	30.7	51.9	0.1	0.4	0.7	1.5
6.2	5.1	193	184	0.0	0.0	-0.1	-0.1	-0.1	0.1
0.1	0.3	16	22	7.9	10.8	0.0	0.1	0.2	0.4
6.7	6.7								
		238	239						
				8.5	11.8				

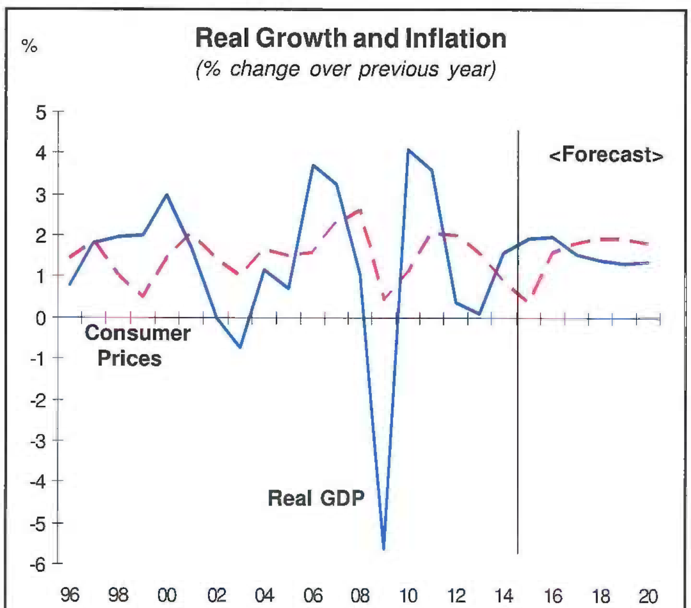
Highest Consumer Confidence in 13 Years

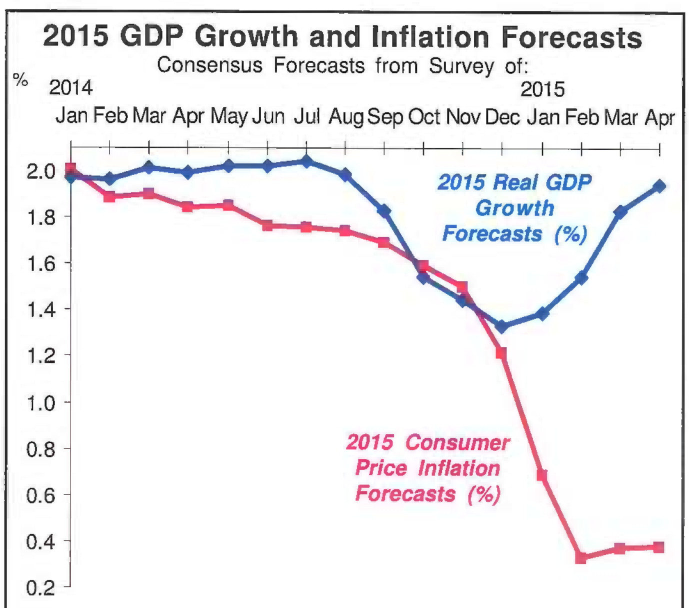
The German economy is surging as the boom in consumer expenditure continues to support 2015 GDP expectations. The expansion appears to becoming more broadbased, easing the reliance on the consistently strong export performance. Downward pressure on energy prices and cheap borrowing have boosted the consumer climate and, according to the latest GfK consumer sentiment survey, confidence has reached its highest level in over 13 years. The robust labour market is improving financial stability. Moreover, rising wages, accompanied by a lower unemployment rate (6.4% in March), are stimulating individuals' willingness to spend. Retail sales dipped slightly m-o-m in February but rose 3.6% (y-o-y) while new car registrations accelerated 9% (y-o-y) in March, indicating a resilient consumer-led GDP expansion in Q1.

Despite the many upsides to the economic outlook, some risks remain. Industrial production climbed a modest 0.2% (m-o-m) in February following January's -0.4% contraction. Industrial orders were weak in February, sliding for a second consecutive month, down 0.9% (m-o-m). Tumbling export orders more than offset strong demand for consumer goods. Furthermore, Greece's future in the Euro bloc remains unclear. As negotiations over debt repayments seemingly stall (and the Greek government riles Germany by demanding €278.7bn in WWII reparations), potential turmoil in the Euro zone could erode a sustained German recovery. Nevertheless, consumer price inflation advanced by 0.3% (y-o-y) in March, led by a less-pronounced decrease in food and energy prices. This eased deflationary pressures. The PMI indicator for both manufacturing and services also improved in March, adding to a generally favourable outlook.

Direction of Trade – 2013

Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
France	9.8	Netherlands	14.2
United Kingdom	7.4	France	7.7
Netherlands	6.9	Belgium	6.4
EU	*60.6*	*EU*	*65.5*
Eastern Europe	*14.3*	*Eastern Europe*	*14.9*
Asia (ex. Japan)	*7.8*	*Asia (ex. Japan)*	*9.4*





	Average % Change on Previous Calendar Year											
	Gross Domestic Product		Household Consumption		Business Investment		Manufacturing Production		Consumer Prices		Hourly Wage Rates	
	Produit Intérieur Brut		*Consommation des Ménages*		*Investissements des Entreprises*		*Production Manufacturière*		*Prix à la Consommation*		*Taux de Salaire Horaire*	
Economic Forecasters	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
Oddo Securities	1.4	1.9	1.7	1.2	0.6	3.6	1.2	2.0	0.2	1.6	1.0	1.6
BNP Paribas	1.2	1.8	1.5	1.1	1.4	5.0	1.2	2.7	0.2	1.2	1.3	1.6
PAIR Conseil	1.2	1.6	1.1	1.3	1.1	2.5	1.9	2.9	0.1	0.9	na	na
BIPE	1.2	1.9	1.5	1.7	0.5	2.4	na	na	-0.1	0.7	0.8	1.0
Barclays Capital	1.2	1.6	1.6	1.5	-0.3	2.9	na	na	0.2	1.0	na	na
Coe-Rexecode	1.2	1.6	1.7	1.5	1.4	3.7	na	na	0.4	1.4	1.5	1.7
Credit Suisse	1.2	1.9	1.2	1.4	1.1	4.1	na	na	0.0	1.0	na	na
Natixis	1.2	1.4	1.3	0.8	0.3	3.1	2.0	3.0	0.3	1.2	1.7	1.5
Oxford Economics	1.2	1.7	1.5	1.7	-0.2	2.1	1.2	2.0	0.3	1.0	1.8	2.3
Citigroup	1.2	1.8	1.3	1.5	0.7	3.0	0.8	2.0	0.2	1.5	1.5	na
La Banque Postale	1.1	1.9	1.4	1.7	0.2	2.6	na	na	0.3	1.0	1.2	1.4
IHS Economics	1.1	1.5	1.4	1.6	0.8	1.9	na	na	-0.1	1.4	na	na
Bank of America - Merrill	1.1	1.5	1.5	1.8	na	na	na	na	0.1	1.0	na	na
Credit Agricole	1.1	1.3	1.3	1.3	0.6	2.4	1.2	1.6	0.0	1.0	na	na
HSBC	1.1	1.3	1.1	0.9	0.9	1.0	1.5	2.3	0.0	0.9	1.1	0.8
Morgan Stanley	1.1	1.7	1.2	1.6	-0.4	3.0	na	na	0.3	1.4	na	na
OFCE	1.1	na	1.4	na	0.2	na	na	na	0.5	na	1.7	na
Goldman Sachs	1.1	1.7	1.1	1.5	-0.4	1.4	na	na	0.0	0.8	na	na
Euler Hermes	1.0	1.4	1.4	1.5	0.7	2.0	na	na	0.1	1.2	na	na
Exane	1.0	1.6	1.5	1.3	1.0	2.2	1.2	2.4	-0.2	0.8	1.1	1.0
UBS	1.0	1.5	1.1	1.5	-0.2	1.3	0.8	1.5	0.3	1.6	na	na
AXA Investment Managers	0.9	1.1	1.2	1.1	-0.4	1.3	na	na	-0.3	0.2	na	na
GAMA	0.9	1.3	1.1	1.0	0.3	1.4	na	na	0.2	1.1	1.1	1.2
Econ Intelligence Unit	0.9	1.2	1.2	1.1	na	na	na	na	0.1	1.0	na	na
Societe Generale	0.8	1.3	1.4	1.5	1.2	2.8	na	na	0.2	1.0	1.5	2.0
Consensus (Mean)	1.1	1.6	1.3	1.4	0.5	2.5	1.3	2.2	0.1	1.1	1.3	1.5
Last Month's Mean	1.0	1.5	1.2	1.3	0.5	2.4	1.2	2.1	0.1	1.1	1.4	1.5
3 Months Ago	0.9	1.3	1.0	1.2	0.4	2.2	0.8	1.7	0.3	1.2	1.3	1.5
High	1.4	1.9	1.7	1.8	1.4	5.0	2.0	3.0	0.5	1.6	1.8	2.3
Low	0.8	1.1	1.1	0.8	-0.4	1.0	0.8	1.5	-0.3	0.2	0.8	0.8
Standard Deviation	0.1	0.2	0.2	0.3	0.6	1.0	0.4	0.5	0.2	0.3	0.3	0.4
Comparison Forecasts												
Government (Apr. '15)	1.0	1.5										
Eur Commission (Jan. '15)	1.0	1.8	1.5	1.6								
IMF (Apr. '15)	1.2	1.5	1.0	1.7	-0.2	2.0			0.1	0.8		
OECD (Nov. '14)	0.8	1.5	1.0	1.5	0.2	2.2						

Government and Background Data

President - Mr. François Hollande (Parti Socialiste). **Prime Minister** - Mr. Manuel Valls (Parti Socialiste). **Parliament** - The Socialists currently have 292 out of the 577 seats in the National Assembly. **Next Elections** - Legislative – first round: May 2017. Presidential – first round: April 2017. **Nominal GDP** - Euro2,050bn (2013). **Population** - 64.3mn (mid-year, 2013). **$/Euro Exchange Rate** - 1.328 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***March 9, 2015***

	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4
Gross Domestic Product	0.4	0.2	***0.6***	***1.1***	***1.2***	***1.4***	***1.5***	***1.5***	***1.5***	***1.5***
Household Consumption	0.8	0.6	***1.2***	***1.2***	***1.2***	***1.4***	***1.3***	***1.3***	***1.3***	***1.3***
Consumer Prices	0.4	0.3	***-0.3***	***-0.1***	***0.1***	***0.4***	***0.9***	***0.9***	***1.0***	***1.0***

Percentage Change (year-on-year).

Historical Data

* % change on previous year	2011	2012	2013	2014
Gross Domestic Product*	2.1	0.4	0.4	0.4
Household Consumption*	0.3	-0.5	0.3	0.6
Business Investment*	4.0	0.3	-0.6	0.7
Manufacturing Production*	3.9	-3.4	-1.1	0.1
Consumer Prices*	2.1	2.0	0.9	0.5
Hourly Wage Rates*	2.1	2.2	1.7	1.4
Unemployment Rate (ILO), %	8.8	9.4	9.9	9.8
Current Account, Euro bn	-22.3	-31.9	-30.5	-21.7
General Govt. Budget Balance (Maastricht definition), Euro bn	-105	-102	-87.1	-84.8
3 mth Euro, % (end yr)	1.4	0.2	0.3	0.1
10 Yr French Govt Bond, % (end yr)	3.2	2.0	2.4	0.8

Year Average		Annual Total				Rates on Survey Date 0.0%		0.4%	
Unemployment Rate, ILO (%)		Current Account (Euro bn)		General Govt Budget Balance (Maastricht) (Euro bn)		3 month Euro Rate (%)		10 Year French Govt Bond Yield (%)	
Taux de Chômage, BIT (%)		*Solde Courant (€ md)*		*Balance Budgétaire (Maastricht) (€ md)*		*Taux d'intéret 3 mois Euro (%)*		*Rendement des obligations d'Etat, 10 ans (%)*	
2015	2016	2015	2016	2015	2016	End Jul'15	End Apr'16	End Jul'15	End Apr'16
10.1	9.8	-10.8	-3.8	-79.1	-72.8	0.1	0.1	0.8	1.0
10.0	9.4	0.0	8.9	-81.8	-72.8	0.1	0.1	0.5	0.6
9.9	9.8	-22.0	-17.9	-84.6	-80.0	0.0	0.0	0.5	0.6
10.1	9.9	-9.5	10.5	-97.5	-96.7	0.0	0.0	0.4	0.3
10.2	10.0	na	na	na	na	na	na	na	na
10.2	10.1	-6.9	-11.6	-80.0	-75.0	0.0	0.0	0.5	0.7
10.2	10.0	na	na	-90.2	-85.0	na	na	na	na
9.7	9.6	-18.0	-15.0	-89.0	-89.0	0.0	0.0	0.4	0.6
9.9	9.6	-23.3	-24.0	-93.9	-89.5	0.0	0.0	0.4	0.4
10.1	9.8	-6.6	4.2	-78.7	-69.1	0.1	0.1	0.2	0.5
10.1	10.0	-13.4	-15.4	-82.9	-76.8	0.0	0.0	0.4	0.5
9.9	9.6	-17.9	-21.1	-83.0	-78.3	na	na	na	na
na	na	-27.4	-25.4	-93.1	-86.5	na	na	na	na
10.2	10.1	-30.5	-31.0	-81.6	-75.8	0.0	0.0	0.7	1.0
10.1	10.0	-18.5	-21.7	-82.4	-80.6	0.1	0.1	0.7	1.3
10.0	9.6	-19.6	-24.1	-79.9	-77.3	na	na	na	na
10.1	na	-28.8	na	-71.1	na	0.1	na	0.6	na
10.5	10.1	na	na	na	na	na	na	na	na
10.1	9.9	-9.6	-8.4	-85.2	-82.9	0.0	0.0	0.5	1.0
10.2	10.2	-22.0	-16.0	-87.0	-80.0	na	na	na	na
9.6	9.4	na	na	na	na	-0.1	-0.1	1.0	1.7
9.6	9.3	na	na	na	na	0.0	0.0	0.5	0.6
10.2	10.3	na	na	-83.0	-79.0	0.1	0.2	0.8	1.1
9.7	9.5	-17.7	-15.8	na	na	na	na	na	na
9.9	9.7	-17.0	-18.0	-87.4	-89.6	0.0	0.0	0.5	0.6
10.0	9.8	-16.8	-13.6	-84.6	-80.9	0.0	0.0	0.5	0.8
10.0	9.9	-18.7	-17.0	-88.4	-84.1				
10.0	9.9	-21.7	-20.0	-90.6	-85.8				
10.5	10.3	0.0	10.5	-71.1	-69.1	0.1	0.2	1.0	1.7
9.6	9.3	-30.5	-31.0	-97.5	-96.7	-0.1	-0.1	0.2	0.3
0.2	0.3	8.1	11.8	6.1	7.0	0.0	0.1	0.2	0.4
10.4	10.2	-29.3	-38.1						
10.1	9.9								
9.8									

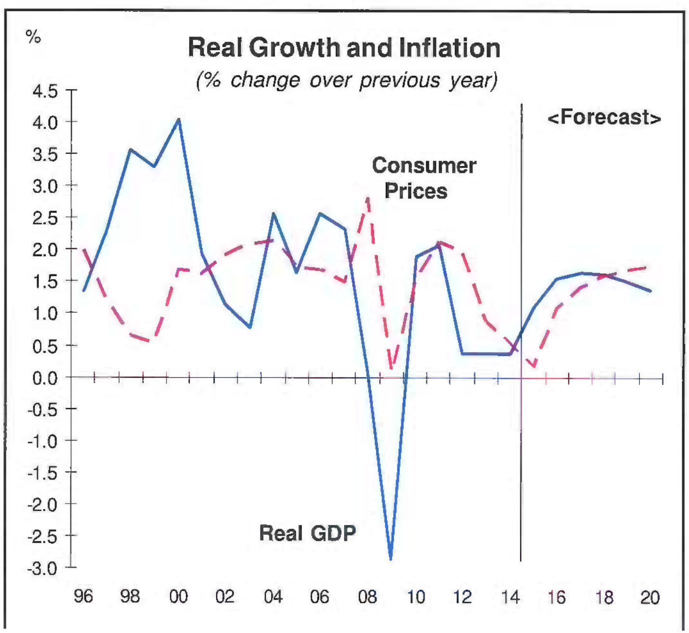
Better GDP Outlook

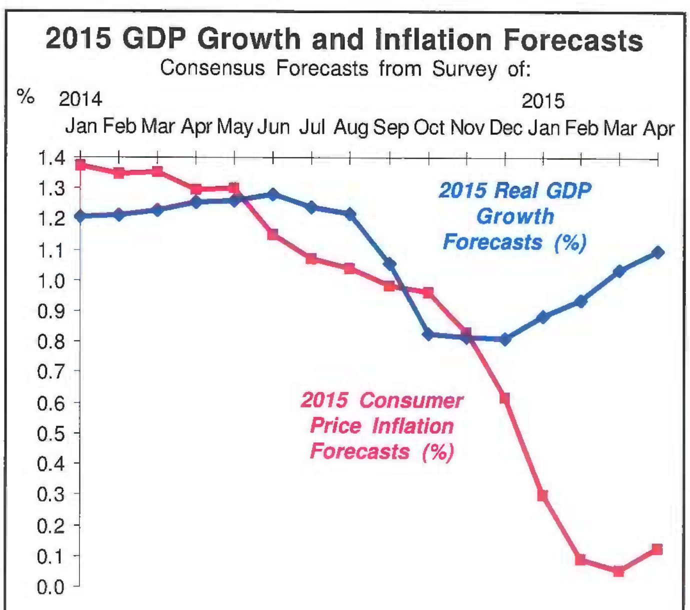
GDP growth slowed from 0.3% (q-o-q) in Q3 to +0.1% in Q4, supported in part by domestic final sales in the run-up to the holidays. With the euro depreciating against the US dollar, net trade helped sustain growth at the end of 2014. Going into this year, lower oil prices are improving corporate and household margins. Still, after a 1.6% (m-o-m) surge in December, goods' consumption halved to 0.7% in January and decelerated further, to +0.1%, in February on the back of falling clothing and automobile purchases post-January sales. However, spending on energy in February was boosted by 0.8% (m-o-m). Elsewhere, the retail PMI eased further below the 50-mark in March as actual sales undershot retailer expectations. Still, the consensus for consumption has edged up this month. March's manufacturing PMI also remained in negative territory, although the pace of falls in output, new orders and employment in the sector did moderate. Meanwhile, manufacturing orders fell by 0.9% (m-o-m) in January, triggered by a sharp 3.4% monthly drop in export orders and raising concerns about the extended weakness in demand for manufactured goods. Production was flat m-o-m in February following January's 0.3% decline, but the y-o-y rate remains negative at -0.8%. Our panel's manufacturing production forecast has also edged up, though.

The public deficit came in at 4% of GDP in 2014, below 4.1% in 2013. The deficit is not expected to decline below the EU-wide 3% limit until 2017, but the news is hopeful according to the Finance Ministry which is projecting a shortfall of 3.8% of GDP in 2015. While maintaining its GDP forecast at 1%, the government has reduced its outlook for 2016 and 2017, from 1.7% and 1.9%, respectively, to 1.5% for both.

Direction of Trade – 2013

Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
Germany	16.6	Germany	19.6
Belgium	7.8	Belgium	11.4
Italy	7.2	Italy	7.6
EU	*60.4*	*EU*	*69.4*
Eastern Europe	*7.3*	*Eastern Europe*	*8.0*
Asia (ex. Japan)	*6.5*	*Asia (ex. Japan)*	*7.2*





	Average % Change on Previous Calendar Year																	
	Gross Domestic Product		Household Consump-tion		Gross Fixed Investment		Company Trading Profits		Manufactur-ing Produc-tion		Retail Prices (RPI-X, underly-ing rate)		Consumer Prices Index		Output Prices		Average Weekly Earnings	
Economic Forecasters	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
Beacon Econ Forecasting	2.9	2.3	2.9	3.0	4.2	1.9	na	na	1.7	1.3	0.9	0.9	-0.1	0.6	0.1	-0.2	2.4	2.9
NIESR	2.9	2.3	3.4	2.5	6.8	6.3	na	na	na	na	1.4	2.1	0.6	1.6	na	na	na	na
Goldman Sachs	2.9	3.0	2.7	2.8	3.7	5.2	na	na	na	na	na	na	0.2	1.5	na	na	na	na
Liverpool Macro Research	2.8	2.5	na	na	na	na	na	na	na	na	2.3	2.4	0.4	1.7	na	na	1.9	3.4
Oxford Economics	2.8	2.8	3.0	2.8	4.1	5.6	4.1	5.1	0.9	1.2	1.2	3.0	0.3	1.8	0.6	1.8	1.9	2.6
Econ Intelligence Unit	2.7	2.4	2.8	2.4	3.4	3.2	na	na	na	na	na	na	0.2	1.4	na	na	na	na
Barclays Capital	2.7	2.2	2.9	1.9	5.4	5.5	na	na	na	na	na	na	0.3	1.5	na	na	na	na
British Chmbrs Commerce	2.7	2.6	2.6	2.5	3.7	6.0	na	na	1.8	2.0	na	na	0.3	1.7	na	na	2.8	3.6
Confed of British Industry	2.7	2.6	3.0	2.6	5.9	6.0	na	na	1.5	1.7	1.5	2.5	0.4	1.8	0.0	1.9	2.2	2.7
ING Financial Markets	2.7	2.6	2.9	2.8	4.6	4.8	na	na	2.0	2.4	na	na	0.4	2.2	0.0	2.7	2.8	4.0
Lombard Street Research	2.7	2.5	3.0	3.2	3.2	4.7	3.0	5.0	na	na	1.5	2.7	0.3	1.7	na	na	2.8	3.0
Citigroup	2.7	3.2	3.4	3.6	4.3	8.1	-0.5	5.7	1.8	2.0	1.4	2.7	0.3	1.5	na	na	2.7	3.4
Experian	2.7	2.4	2.7	2.3	4.5	4.4	na	na	2.3	2.5	2.3	3.0	0.8	1.5	na	na	2.5	3.3
Bank of America - Merrill	2.6	2.8	2.4	2.4	5.5	8.5	na	na	1.9	3.7	1.1	2.5	0.2	1.4	na	na	na	na
Credit Suisse	2.6	2.4	2.9	2.2	5.3	7.2	na	na	na	na	1.2	na	0.0	1.5	na	na	na	na
HSBC	2.6	2.6	2.3	2.3	4.3	6.9	na	na	1.7	2.4	1.4	2.7	0.3	1.5	na	na	2.7	3.0
IHS Economics	2.6	2.8	2.8	3.1	3.4	6.2	na	na	2.2	2.5	1.4	2.4	0.3	1.6	-1.1	1.5	2.5	3.7
Schroders	2.6	2.0	2.7	2.2	3.9	4.3	na	na	1.7	1.5	1.4	2.6	0.6	2.2	na	na	2.8	3.3
Societe Generale	2.6	2.0	2.6	1.8	8.1	5.4	na	na	na	na	na	na	0.4	1.8	na	na	2.5	2.8
Deutsche Bank	2.5	2.3	2.4	2.3	4.3	5.5	na	na	3.0	1.7	2.4	1.3	0.4	1.9	-0.8	1.8	2.0	3.0
Cambridge Econometrics	2.4	2.0	2.6	2.1	4.0	3.7	na	na	3.8	3.0	1.7	2.5	0.8	1.7	na	na	3.0	3.4
JP Morgan	2.4	2.6	2.5	2.1	3.2	5.5	na	na	na	na	na	na	0.4	1.6	na	na	na	na
RBS Markets	2.4	2.0	2.7	2.0	4.0	4.2	na	na	1.8	1.4	1.1	1.9	0.2	1.2	-0.8	1.5	2.8	2.9
UBS	2.4	2.9	2.2	2.7	2.9	6.4	na	na	na	na	na	na	0.1	1.7	na	na	2.3	2.5
Nomura	2.3	2.6	2.7	4.1	4.0	5.1	na	na	1.0	1.4	1.4	3.0	0.3	1.9	-0.7	1.5	2.2	4.3
Economic Perspectives	2.2	2.3	2.7	2.3	3.7	4.8	5.0	0.0	2.0	1.4	1.4	2.8	0.7	2.4	0.8	2.2	2.3	2.8
Consensus (Mean)	2.6	2.5	2.8	2.6	4.4	5.4	2.9	3.9	1.9	2.0	1.5	2.4	0.4	1.6	-0.2	1.6	2.5	3.2
Last Month's Mean	2.7	2.5	2.9	2.6	4.9	5.6	6.9	3.2	2.1	2.1	1.4	2.5	0.5	1.7	-0.1	1.5	2.5	3.2
3 Months Ago	2.6	2.4	2.8	2.5	5.8	5.2	6.4	3.6	1.8	2.1	1.8	2.5	0.9	1.8	0.5	1.6	2.5	3.2
High	2.9	3.2	3.4	4.1	8.1	8.5	5.0	5.7	3.8	3.7	2.4	3.0	0.8	2.4	0.8	2.7	3.0	4.3
Low	2.2	2.0	2.2	1.8	2.9	1.9	-0.5	0.0	0.9	1.2	0.9	0.9	-0.1	0.6	-1.1	-0.2	1.9	2.5
Standard Deviation	0.2	0.3	0.3	0.5	1.2	1.5	2.4	2.6	0.7	0.7	0.4	0.6	0.2	0.3	0.7	0.8	0.3	0.5
Comparison Forecasts																		
Treasury - OBR (Dec. '14)	2.4	2.2	2.8	2.2	8.4	5.9					2.2	2.9	1.2	1.7				
Eur Commission (Jan. '15)	2.6	2.4	2.7	2.3	6.9	6.3												
IMF (Apr. '15)	2.7	2.3	3.2	2.9	3.2	4.3							0.1	1.7				
OECD (Nov. '14)	2.7	2.5	2.4	2.1	7.1	7.6							2.1					

Government and Background Data

Prime Minister - Mr. David Cameron (Conservative Party). **Parliament** -The Conservative party has formed a coalition with the Liberal Democrat party, with a working majority in the 650-seat House of Commons (lower house). **Next Election** - May 2015 (general election). **Nominal GDP** - £1,613bn (2013). **Population** - 63.1mn (mid-year, 2013). **$/£ Exchange Rate** - 1.564 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***March 9, 2015***

	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4
Gross Domestic Product	2.5	2.7	***2.7***	***2.6***	***2.6***	***2.7***	***2.6***	***2.5***	***2.4***	***2.3***
Household Consumption	2.1	2.2	***2.7***	***2.9***	***2.8***	***3.0***	***2.9***	***2.7***	***2.6***	***2.5***
Consumer Prices	1.4	0.9	***0.2***	***0.3***	***0.4***	***0.9***	***1.4***	***1.7***	***1.8***	***1.9***

Percentage Change (year-on-year).

Historical Data

** % change on previous year*	2011	2012	2013	2014
Gross Domestic Product*	1.6	0.7	1.7	2.8
Household Consumption*	-0.1	1.5	1.7	2.5
Gross Fixed Investment*	2.3	0.7	3.4	7.8
Company Trading Profits*	7.1	3.4	2.6	10.0
Manufacturing Production*	1.8	-1.3	-0.7	2.8
Retail Prices (RPI-X underlying rate)*	5.3	3.2	3.1	2.4
Consumer Prices Index*	4.5	2.8	2.5	1.5
Output Prices*	4.8	2.1	1.3	0.0
Average Weekly Earnings*	2.7	1.3	1.3	1.1
Unemployment Rate % (LFS)	8.1	8.0	7.6	6.2
Current Account, £ bn	-27.0	-61.9	-76.7	-97.9
Public Sector Net Borrowing (excl. financial interventions), fiscal yrs, £ bn	113	119.4*	97.3	92.7 *e*
3 mth Interbank, % (end yr)	1.1	0.5	0.5	0.6
10 Yr Gilt Yields, % (end yr)	2.1	2.0	2.8	1.8

** Includes Royal Mail pension fund transfer of £28bn.*
e = consensus estimate based on latest survey

Unemployment Rate (%) (Labour Force Survey) Year Average 2015	2016	Current Account (£ bn) Annual Total 2015	2016	Public Sector Net Borrowing (£ bn) Fiscal Years (Apr-Mar) FY 15-16	FY 16-17	3 month Interbank Rate (%) Rates on Survey Date 0.6% End Jul'15	End Apr'16	10 Year Gilt Yield (%) 1.8% End Jul'15	End Apr'16
5.5	5.6	-76.9	-82.6	78.4	68.2	0.8	1.1	1.8	1.6
5.4	5.3	-74.0	-75.0	85.0	44.0	0.6	0.8	1.8	2.2
5.4	5.1	-114.9	-101.3	na	na	na	na	na	na
na	na	-72.0	-72.3	75.8	56.6	0.9	1.2	na	na
5.3	5.1	-86.6	-78.8	67.0	51.6	0.5	0.8	1.9	2.2
5.5	5.5	-84.3	-78.0	na	na	na	na	na	na
5.5	5.6	na	na	na	na	na	na	na	na
5.4	5.0	-90.0	-83.0	75.0	56.0	0.5	0.9	2.1	2.6
5.4	5.2	-82.0	-71.0	81.4	66.5	na	na	na	na
5.5	5.0	-80.0	-80.0	78.0	55.0	0.7	1.3	2.0	2.5
5.6	5.2	-80.0	-75.0	na	na	0.6	0.8	1.8	2.0
5.1	4.2	-91.9	-95.2	76.1	35.9	0.5	1.0	na	na
5.5	5.2	-88.2	-77.9	67.0	51.5	0.9	1.1	2.2	3.0
na	na	-54.0	-48.0	na	na	na	na	na	na
5.2	4.8	na	na	na	na	na	na	na	na
5.5	5.3	na	na	na	na	na	na	na	na
5.4	5.0	-80.6	-67.5	77.2	54.9	0.6	1.1	2.1	2.8
5.4	5.2	-98.0	-95.0	80.0	70.0	0.6	1.1	1.9	2.4
5.0	4.7	-98.3	-95.9	84.3	76.1	0.5	0.8	na	na
5.5	5.3	-75.0	-55.0	75.0	40.0	0.6	0.6	1.6	2.3
na	na	-54.5	-35.8	76.0	56.1	0.6	1.2	na	na
5.4	5.0	na	na	na	na	na	na	na	na
5.5	5.2	-76.0	-59.0	78.0	46.0	0.7	0.9	1.7	1.9
5.5	5.3	na	na	na	na	0.9	1.6	2.3	2.5
5.1	4.2	-80.1	-84.7	61.4	35.5	0.6	0.9	2.0	3.0
5.7	5.5	-75.0	-60.0	80.0	65.0	0.6	1.3	2.0	2.3
5.4	5.1	-81.5	-74.8	76.2	54.6	0.6	1.0	1.9	2.4
5.4	5.1	-84.8	-80.2	77.1	58.2				
5.5	5.2	-78.2	-72.7	80.1	62.0				
5.7	5.6	-54.0	-35.8	85.0	76.1	0.9	1.6	2.3	3.0
5.0	4.2	-114.9	-101.3	61.4	35.5	0.5	0.6	1.6	1.6
0.2	0.4	13.6	16.5	6.1	11.9	0.1	0.2	0.2	0.4
5.4	5.2			75.9	40.9				
5.6	5.4								

Election Adds Uncertainty to Strong Outlook

In the run-up to the general election on May 7, better-than-expected data confirmed GDP growth of 2.8% in 2014. The dominant services sector rose by 0.9% (q-o-q) and consumer spending advanced by 0.6% in Q4, supported by a 1.4% (q-o-q) surge in real incomes. According to the GfK consumer survey in March, confidence has risen to its highest level in over 12 years. Despite a slowdown in house prices [which increased by 7.2% (y-o-y) in February compared with 8.4% in January] consumers are benefiting from historically-low inflation and subdued energy costs. Retail sales soared 0.7% (m-o-m) in February, whilst car sales rocketed by 6% (y-o-y) in March and were at their highest monthly level since August 1998. The thriving UK automotive sector has seen demand buoyed by low interest rates at home and strong exports abroad. However, the record current account deficit, which widened to 5.5% of GDP in 2014, is now being closely monitored by the Bank of England's Financial Policy Committee. It fears a deterioration in market sentiment in the event of a sudden economic slump.

An unexpected -0.2% (m-o-m) drop in services output in January might not impact Q1 GDP too significantly, as the closely-watched services PMI hit a seven-month high of 58.9 in March, aided by faster growth in new business. Meanwhile, annual inflation was 0% in March, unchanged for a second consecutive month. Core inflation unexpectedly fell to 0.9% (y-o-y), ensuring that the deflationary threat cannot be dismissed. Yet, this anticipated temporary price slide continues to improve individuals' purchasing power and seems certain to delay a rise in interest rates.

UK Official Bank Rate – Apr. 13, 2015 = 0.50%

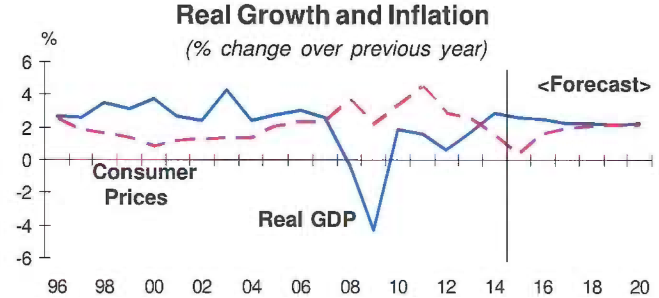
FORECASTS	End Jun. 2015	End Sep. 2015	End Dec. 2015	End Mar. 2016
Consensus Mean Average:	0.52%	0.55%	0.63%	0.84%
Mode (most frequent forecast):	0.50%	0.50%	0.50%	0.75%

Direction of Trade – 2013

Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
Germany	9.0	Germany	13.9
United States	8.8	China	8.5
Netherlands	7.6	Netherlands	8.5
EU	*45.9*	*EU*	*53.7*
Eastern Europe	*5.2*	*Asia (ex. Japan)*	*13.0*
Asia (ex. Japan)	*5.0*	*Eastern Europe*	*6.9*

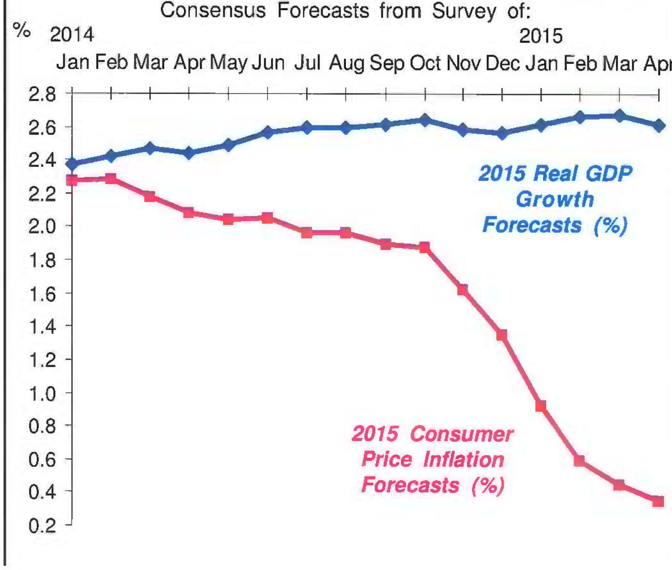
Real Growth and Inflation

(% change over previous year)



2015 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



	Average % Change on Previous Calendar Year													
	Gross Domestic Product		Household Consumption		Gross Fixed Investment		Industrial Production		Consumer Prices		Producer Prices		Contractual Hourly Earnings	
	Prodotto Interno Lordo		*Consumi delle Famiglie*		*Investimenti Fissi Lordi*		*Produzione Industriale*		*Prezzi al Consumo*		*Prezzi alla Produzione*		*Retribuzione Orarie Contrattuali*	
Economic Forecasters	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
Centro Europa Ricerche	0.9	1.3	0.5	0.8	0.8	2.0	na	na	0.3	1.5	na	na	na	na
Citigroup	0.8	1.4	1.1	0.9	0.5	2.5	na	na	0.2	1.0	na	na	na	na
ABI	0.7	1.5	0.4	0.9	0.2	2.3	1.1	2.5	0.2	0.7	-1.0	0.8	1.3	1.5
Banca Nzle del Lavoro	0.7	1.3	0.7	0.9	1.3	2.9	1.0	2.2	0.1	1.2	-0.8	1.3	1.0	1.0
Barclays Capital	0.7	1.3	0.3	0.7	-1.0	0.6	na	na	0.3	0.8	na	na	na	na
Credit Suisse	0.7	1.6	0.8	1.0	-0.1	2.9	0.6	1.8	0.0	0.7	na	na	na	na
ING Financial Markets	0.7	1.3	0.5	0.7	-0.1	1.6	na	na	0.1	0.9	-1.4	1.3	1.2	1.3
Prometeia	0.7	1.4	1.1	0.8	-0.4	2.8	1.3	2.7	-0.2	1.2	-3.4	3.0	1.2	1.3
REF Ricerche	0.7	1.2	0.7	0.9	-0.2	2.1	0.7	1.2	0.2	0.6	-1.0	na	1.1	1.3
UBS	0.7	1.3	0.8	0.9	0.0	1.1	na	na	na	na	0.5	2.0	1.4	1.4
Econ Intelligence Unit	0.5	0.9	0.6	0.7	0.2	0.9	0.5	1.3	-0.5	0.4	-2.0	0.7	na	na
Confindustria	0.5	1.1	0.5	0.8	-0.1	1.9	na	na	0.2	0.6	na	na	na	na
HSBC	0.5	0.8	0.6	0.6	0.0	0.7	0.2	2.1	0.2	0.7	na	na	0.7	0.7
Goldman Sachs	0.4	0.9	0.5	0.7	-0.4	1.1	0.6	2.1	0.1	0.3	na	na	na	na
Intesa Sanpaolo	0.4	1.0	0.8	1.1	0.3	2.1	0.7	0.9	0.0	1.1	-2.4	0.2	1.1	1.1
Moody's Analytics	0.4	1.1	0.4	1.2	0.3	1.7	0.5	3.2	0.1	1.1	-1.8	1.5	na	na
Oxford Economics	0.3	1.0	0.5	0.7	-0.2	1.6	0.7	1.9	0.1	0.8	-2.3	1.2	1.5	0.6
Bank of America - Merrill	0.3	0.9	0.6	0.9	-0.5	-0.1	0.9	4.0	-0.1	0.1	na	na	na	na
Consensus (Mean)	0.6	1.2	0.6	0.8	0.0	1.7	0.7	2.2	0.1	0.8	-1.6	1.3	1.2	1.1
Last Month's Mean	0.6	1.1	0.7	0.8	0.0	1.7	0.6	2.0	0.0	0.8	-1.2	1.3	1.2	1.2
3 Months Ago	0.4	1.0	0.5	0.7	-0.3	1.5	0.2	1.8	0.2	0.7	-0.1	1.3	1.0	1.0
High	0.9	1.6	1.1	1.2	1.3	2.9	1.3	4.0	0.3	1.5	0.5	3.0	1.5	1.5
Low	0.3	0.8	0.3	0.6	-1.0	-0.1	0.2	0.9	-0.5	0.1	-3.4	0.2	0.7	0.6
Standard Deviation	0.2	0.2	0.2	0.2	0.5	0.8	0.3	0.9	0.2	0.4	1.1	0.8	0.2	0.3
Comparison Forecasts														
Banca d'Italia (Jan. '15)	0.4	1.2	0.9	0.9	-0.7	2.5								
Government (Apr. '15)	0.7	1.4												
Eur Commission (Jan. '15)	0.6	1.3	0.5	0.5	1.0	4.1								
IMF (Apr. '15)	0.5	1.1	1.2	1.1	-0.3	0.4			0.0	0.8				
OECD (Nov. '14)	0.2	1.0	0.3	0.5	0.1	2.0			0.9					

Government and Background Data

Prime Minister - Mr. Matteo Renzi. **Parliament** - A coalition government with representation from Renzi's Democratic Party, the New Centre-Right, the Union of the Centre and Civic Choice was formed in February 2014. **Next Elections** - By 2018 (Parliamentary); 2020 (presidential). **Nominal GDP** - Euro1,560bn (2013). **Population** - 61.0mn (mid-year, 2013). **$/Euro Exchange Rate** - 1.328 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***March 9, 2015***

	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4
Gross Domestic Product	-0.5	-0.3	***-0.1***	***0.3***	***0.7***	***1.1***	***1.2***	***1.1***	***1.1***	***1.1***
Household Consumption	0.4	0.8	***0.5***	***0.5***	***0.6***	***0.9***	***1.0***	***1.0***	***0.9***	***0.8***
Consumer Prices	-0.1	0.1	***-0.3***	***-0.2***	***0.0***	***0.2***	***0.6***	***0.7***	***0.9***	***0.9***

Percentage Change (year-on-year).

Historical Data

** % change on previous year*	2011	2012	2013	2014
Gross Domestic Product*	0.6	-2.8	-1.7	-0.4
Household Consumption*	0.0	-3.9	-2.9	0.3
Gross Fixed Investment*	-1.9	-9.3	-5.8	-3.3
Industrial Production*	1.2	-6.4	-3.1	-0.8
Consumer Prices*	2.8	3.1	1.2	0.2
Producer Prices*	4.8	3.6	-1.1	-1.5
Contractual Hourly Earnings*	1.7	1.5	1.4	1.2
Unemployment Rate,%	8.4	10.6	12.2	12.7
Current Account, Euro bn	-50.4	-6.9	15.5	29.6
General Govt. Budget Balance (Maastricht definition), Euro bn	-57.2	-48.3	-47.5	-49.1
3 mth Euro, % (end yr)	1.4	0.2	0.3	0.1
10 yr Italian Govt Bond, % (end yr)	7.0	4.5	4.1	1.9

Year Average: Unemployment Rate (%) / Tasso di Disoccupazione (%) 2015	2016	Annual Total: Current Account (Euro bn) / Partite Correnti (€ mld) 2015	2016	Annual Total: General Govt Budget Bal (Maastricht) (Euro bn) / Indebitamento netto (Maastricht) (€ mld) 2015	2016	Rates on Survey Date 0.0%: 3 month Euro Rate (%) / Interessi Euro Trimestrali (%) End Jul'15	End Apr'16	Rates on Survey Date 1.3%: 10 Year Italian Govt Bond Yield (%) / Buoni del Tesoro Decennali (%) End Jul'15	End Apr'16
12.3	12.0	51.9	56.6	-42.8	-24.8	0.0	0.1	1.5	1.5
12.7	12.5	31.7	32.9	-47.3	-33.8	0.1	0.1	na	na
12.2	11.4	38.7	55.2	-42.3	-28.5	0.1	0.2	1.3	1.6
12.7	12.3	na	na	na	na	na	na	na	na
12.4	12.3	na	na	na	na	na	na	na	na
12.6	12.2	na	na	-45.0	-38.0	na	na	na	na
12.6	11.9	32.3	25.0	-44.2	-40.3	na	na	na	na
12.7	12.3	44.1	41.7	-48.1	-45.1	0.0	0.0	1.2	1.3
12.5	12.2	57.4	57.4	-43.5	-41.1	0.0	0.0	1.6	1.7
13.0	12.9	na	na	na	na	-0.1	-0.1	2.1	2.8
13.3	12.6	22.6	19.7	na	na	na	na	na	na
12.9	12.6	42.1	49.3	-43.8	-42.1	na	na	na	na
12.5	11.7	30.3	34.9	-48.9	-39.8	0.1	0.1	1.1	2.4
13.5	13.1	na	na	na	na	na	na	na	na
12.6	12.2	39.7	35.8	-46.8	-27.5	0.0	0.0	1.1	1.2
12.8	12.6	34.4	8.0	na	na	0.0	0.0	1.8	1.9
12.6	12.4	39.7	35.8	-45.5	-39.6	0.0	0.0	1.3	1.3
12.6	12.0	47.7	52.9	-45.6	-33.1	na	na	na	na
12.7	12.3	39.4	38.9	-45.3	-36.2	0.0	0.1	1.4	1.7
12.8	12.4	38.6	37.3	-45.7	-36.8				
12.9	12.6	27.9	27.9	-46.4	-40.5				
13.5	13.1	57.4	57.4	-42.3	-24.8	0.1	0.2	2.1	2.8
12.2	11.4	22.6	8.0	-48.9	-45.1	-0.1	-0.1	1.1	1.2
0.3	0.4	9.5	15.3	2.1	6.5	0.1	0.1	0.4	0.5
12.8	12.8								
12.8	12.6	42.6	42.9						
12.6	12.3								
12.5									

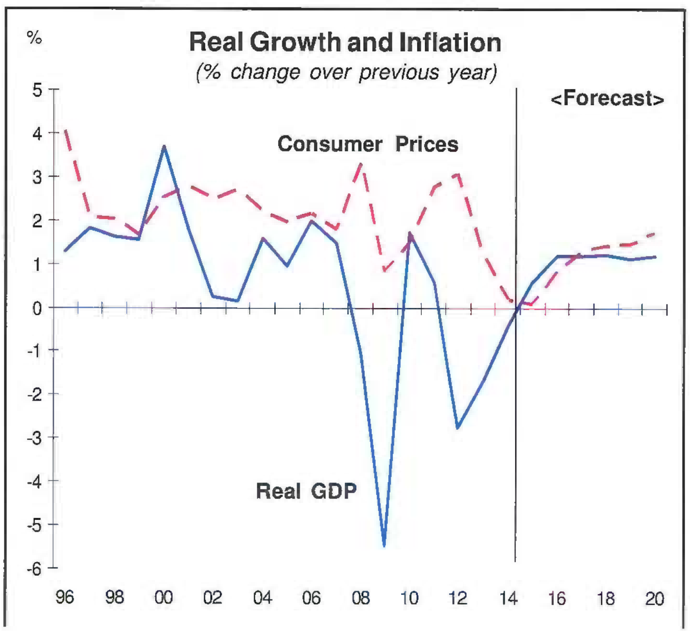
Sentiment Rises But Progress Remains Slow

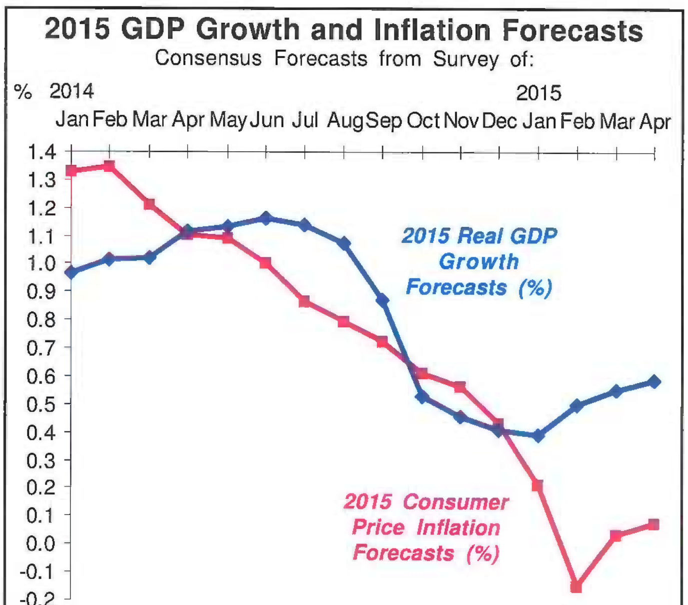
Sentiment is rising amongst consumers and businesses as the economy slowly extricates itself from three years of recession. The Istat index of consumer confidence climbed to 110.9 from 107.7 in March, underlining expectations that seem to be spreading through the Euro area. Optimism on the recovery remains cautious, though. Unemployment worsened to 12.7% in February, signalling continued weakness in the labour market. Exports dropped by 2.5% (m-o-m) in January but industrial production grew by 0.6% (m-o-m) in February to virtually offset January's -0.7% slump. The closely watched manufacturing PMI accelerated to an 11-month high of 53.3 in March, indicating a pick-up in momentum as output and employment expanded. Furthermore, investment may be on the cusp of a revival as the leading business confidence indicator soared to its highest level in seven years. Our panel anticipate no growth in investment in 2015, though.

Consumer price inflation was -0.1% (y-o-y) in March, weighed down by a decrease in core inflation. Ongoing deflationary pressures would be a significant burden on Italian debt. Public finances have been strained by prolonged stagnation, yet the Economy minister has stressed that the 2015 deficit target (2.6% of GDP) will be met and, therefore, comply with the Maastricht limit of 3% of GDP. Despite this, national debt is still at staggeringly high levels and so commitment to delivering economic reforms remains integral to adhering to European Commission guidelines. Prime Minister Renzi faces ongoing public opposition, this time to prospective education reforms which aim to raise performances in sub-standard schools. The reforms are seen as a vital step in reversing long-term growth and labour productivity stagnation.

Direction of Trade – 2013

Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
Germany	12.6	Germany	15.5
France	11.0	France	8.9
United States	6.7	China	6.7
EU	*54.4*	*EU*	*53.1*
Eastern Europe	*14.0*	*Eastern Europe*	*16.0*
Middle East	*5.5*	*Asia (ex. Japan)*	*10.2*





	Average % Change on Previous Calendar Year																Annual Total	
	Gross Domestic Product		Personal Expenditure		Machinery & Equipment Investment		Net Operating Surplus: Corporations		Industrial Production		Consumer Prices		Industrial Product Prices		Average Hourly Earnings		Housing Starts (thousand units)	
	Produit Intérieur Brut		*Dépenses de Consommation des Ménages*		*Investissement Productif*		*Excédent d'exploitation net: sociétés*		*Production Industrielle*		*Prix à la Consommation*		*Prix des Produits Industriels*		*Rémunération Horaire Moyenne*		*Construction de Logements mises en chantier, milliers*	
Economic Forecasters	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**
Informetrica	2.4	2.2	1.8	2.2	0.8	5.0	2.0	6.0	2.1	3.0	0.8	2.1	-3.0	2.0	2.1	3.2	170	180
Royal Bank of Canada	2.4	2.3	2.4	2.6	-1.5	5.1	-10.9	11.1	na	na	1.0	2.8	na	na	na	na	182	179
Oxford Economics	2.2	2.2	2.4	2.4	1.3	1.5	3.5	3.9	1.3	1.4	0.8	2.2	-0.8	2.1	na	2.5	177	184
Citigroup	2.1	1.8	2.3	2.0	4.8	0.9	na	na	-0.4	-0.5	1.1	1.7	na	na	na	na	na	na
Conf Board of Canada	2.0	2.2	2.5	2.3	-2.1	4.9	na	na	na	na	1.3	2.7	na	na	na	na	170	178
Desjardins	2.0	2.2	2.4	2.1	-2.6	4.4	-5.5	6.0	na	na	0.9	2.3	-0.8	2.8	2.2	2.4	177	183
Econ Intelligence Unit	2.0	2.3	1.9	1.6	-2.5	0.3	na	na	na	na	0.7	2.3	na	na	na	na	na	na
Economap	2.0	2.3	2.2	2.3	-2.5	2.4	-16.0	9.0	0.6	2.6	1.1	2.0	-2.0	2.4	2.5	2.4	179	180
National Bank of Canada	2.0	2.0	2.2	2.1	-0.1	0.6	-2.0	4.2	na	na	1.0	2.2	na	na	na	na	175	170
University of Toronto	2.0	2.5	2.2	1.8	0.7	4.3	-0.4	6.1	na	na	0.9	1.9	na	na	na	na	176	186
BMO Capital Markets	1.9	2.2	2.1	2.1	-2.5	2.4	-15.0	7.5	0.7	2.5	1.2	2.2	-2.0	2.8	2.7	2.8	178	180
IHS Economics	1.9	2.2	2.1	2.4	-0.8	1.5	1.5	2.4	-0.7	1.7	1.3	2.2	-2.6	2.5	na	na	173	180
Scotia Economics	1.9	2.0	2.4	2.2	0.6	4.0	0.5	6.0	2.8	3.4	1.0	2.1	na	na	na	na	182	178
Bank of America - Merrill	1.9	2.1	2.3	1.8	0.3	1.8	na	na	na	na	1.0	1.8	na	na	na	na	185	181
JP Morgan	1.8	2.3	1.6	2.1	-1.2	3.7	na	na	na	na	0.7	2.2	-1.3	1.5	na	na	na	na
CIBC World Markets	1.7	2.6	2.0	1.6	-0.3	5.2	na	na	na	na	0.9	2.2	na	na	na	na	187	187
Capital Economics	1.5	1.0	2.0	1.0	0.0	0.5	na	na	1.5	1.5	1.0	1.5	na	na	na	na	165	140
Consensus (Mean)	2.0	2.1	2.2	2.0	-0.4	2.9	-4.2	6.2	1.0	1.9	1.0	2.1	-1.8	2.3	2.4	2.7	177	178
Last Month's Mean	2.1	2.2	2.4	2.0	-0.5	2.8	-3.8	5.4	1.2	1.9	0.9	2.1	-1.6	2.3	2.4	2.6	181	178
3 Months Ago	2.3	2.2	2.4	2.1	1.5	3.5	-1.3	5.4	1.9	2.2	1.1	2.1	-0.4	1.8	2.3	2.6	185	179
High	2.4	2.6	2.5	2.6	4.8	5.2	3.5	11.1	2.8	3.4	1.3	2.8	-0.8	2.8	2.7	3.2	187	187
Low	1.5	1.0	1.6	1.0	-2.6	0.3	-16.0	2.4	-0.7	-0.5	0.7	1.5	-3.0	1.5	2.1	2.4	165	140
Standard Deviation	0.2	0.3	0.2	0.4	1.9	1.8	7.3	2.5	1.2	1.2	0.2	0.3	0.9	0.5	0.3	0.3	6	12
Comparison Forecasts																		
IMF (Apr. '15)	2.2	2.0	2.3	2.2							0.9	2.0						
OECD (Nov. '14)	2.6	2.4	2.6	2.4							1.8							

Government and Background Data

Prime Minister - Mr. Stephen Harper (Conservative). **Government** - The Conservatives hold 167 out of 308 seats in parliament (155 seats are needed for a clear majority). **Next Election** - by May 2015 (general election). **Nominal GDP** - C$1,881bn (2013). **Population** - 35.2mn (mid-year, 2013). **C$/$ Exchange Rate** - 1.030 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of March 9, 2015

	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4
Gross Domestic Product	2.7	2.6	***2.6***	***2.1***	***1.8***	***1.8***	***2.0***	***2.2***	***2.4***	***2.5***
Personal Expenditure	2.8	2.6	***2.8***	***2.3***	***2.2***	***2.1***	***2.0***	***2.1***	***2.1***	***2.1***
Consumer Prices	2.1	1.9	***0.8***	***0.5***	***0.7***	***1.3***	***2.1***	***2.2***	***2.2***	***2.1***

Percentage Change (year-on-year).

Historical Data

** % change on previous year*	2011	2012	2013	2014
Gross Domestic Product*	3.0	1.9	2.0	2.5
Personal Expenditure*	2.2	1.9	2.5	2.8
Machinery & Eqpt Investment*	8.1	1.9	-1.7	0.7
Net Operating Surplus: Corporations*	15.4	-4.2	-0.6	9.0
Industrial Production*	4.1	1.4	1.8	4.1
Consumer Prices*	2.9	1.5	0.9	1.9
Industrial Product Prices*	6.9	1.1	0.4	2.5
Average Hourly Earnings*	2.0	2.0	1.7	2.4
Housing Starts, '000 units	194	215	188	189
Unemployment Rate, %	7.5	7.4	7.1	6.9
Current Account, C$ bn	-47.2	-59.9	-56.3	-43.5
Federal Govt Budget Balance, fiscal years, C$ bn	-26.3	-18.4	-5.2	-2.0 *e*
3 mth Trsy Bill, % (end yr)	0.8	0.9	0.9	0.9
10 Yr Govt Bond, % (end yr)	1.9	1.8	2.8	1.8

e = consensus estimate based on latest survey

Year Average		Annual Total		Fiscal Years (Apr-Mar)		Rates on Survey Date 0.6%		1.4%	
Unemploy - ment Rate (%)		Current Account (C$ bn)		Federal Govt Budget Balance (C$ bn)		3 month Treasury Bill Rate (%)		10 Year Government Bond Yield (%)	
Taux de Chômage (%)		*Balance Courante (C$ md)*		*Balance Budgétaire (C$ md)*		*Rendement sur les Bons du Trésor de 3 mois %*		*Rendement des Obligations d'État de 10 ans %*	
2015	2016	2015	2016	FY 15-16	FY 16-17	End Jul'15	End Apr'16	End Jul'15	End Apr'16
6.8	6.3	-50.0	-45.0	0.5	2.0	0.7	0.9	1.6	2.1
6.6	6.3	-55.0	-25.9	na	na	0.8	1.0	1.6	2.4
6.7	6.6	-57.4	-53.4	na	na	0.8	1.1	1.5	1.9
6.8	6.9	-81.7	-75.3	-1.5	0.0	0.8	0.8	1.6	1.9
6.7	6.6	-59.0	-31.0	na	na	na	na	1.4	1.8
6.8	6.6	-57.0	-41.5	0.0	3.0	0.7	1.1	1.5	2.0
6.8	6.6	-36.0	-38.8	na	na	na	na	1.6	1.9
6.7	6.4	-57.0	-40.0	0.0	1.0	0.6	0.6	1.5	1.8
6.8	6.7	-52.6	-44.5	na	na	0.6	0.7	1.7	2.0
6.7	6.5	-58.0	-42.5	na	na	0.6	1.2	1.7	2.7
6.8	6.6	-58.0	-39.0	1.0	2.0	0.6	0.6	1.4	1.8
7.0	6.8	-69.2	-42.8	na	na	na	na	1.8	2.3
6.8	6.8	-66.0	-55.0	0.5	2.0	0.5	0.5	1.6	2.1
6.8	6.7	-53.6	-44.0	na	na	na	na	na	na
6.7	6.5	-72.3	-55.0	na	na	na	na	na	na
6.9	6.6	-71.5	-46.4	na	na	0.6	0.8	1.6	2.0
7.0	7.3	-74.7	-53.4	na	na	0.4	0.2	1.5	2.3
6.8	6.6	-60.5	-45.5	0.1	1.7	0.6	0.8	1.6	2.1
6.7	6.6	-60.1	-49.1	-1.0	1.4				
6.6	6.5	-48.7	-41.9	0.6	3.0				
7.0	7.3	-36.0	-25.9	1.0	3.0	0.8	1.2	1.8	2.7
6.6	6.3	-81.7	-75.3	-1.5	0.0	0.4	0.2	1.4	1.8
0.1	0.2	10.9	11.0	0.9	1.0	0.1	0.3	0.1	0.3
6.6									

Winter and Commodity Crosswinds

The 2015 outlook for GDP continues to falter in the wake of weak oil prices. The energy sector has been adversely impacted, with oil companies cutting back on investment and employment. Government finances have also been hit, especially in energy-producing Alberta where the provincial government has hiked taxes and slashed spending in response. Some observers suggest that Q1 GDP could well post a decline. January output-based GDP contracted by 0.1% (m-o-m) following a +0.3% jump in December, leaving the y-o-y rate down from 2.8% to an estimated 2.4%. However, surprisingly, energy was not the source of the decline – it soared by 1.3% (m-o-m) following a 1.5% drop in December, probably because of the cold weather and as payback for holiday shutdowns. Instead, a 0.3% decline in services output (led by retrenchment in wholesale and retail trade) pushed GDP into negative territory. On the upside, a better-than-expected March employment report, coupled with housing starts returning to levels of 189.7mn units during the same month, does offer some support to cautious households.

Goods-producing industries recorded a 0.3% (m-o-m) rise, powered by a 1.9% surge in agriculture, forestry & fishing, and by a 1.4% advance in mining, quarrying, oil & gas extraction. However, manufacturing registered a 0.7% contraction, and construction activity fell, too. Manufacturing sales tumbled in January, by 1.7% (m-o-m), accentuating fears of softer global demand. Our panel's industrial production outlook has faltered, although the Bank of Canada suggests that the negative impact from low oil prices was felt mostly in Q4 2014 and Q1 2015. Q2 could see a turnaround although the economy will still be adjusting to lower price levels for commodities.

Canada Overnight Lending Rate – Apr. 13, 2015 = 0.75%

FORECASTS	End Jun. 2015	End Sep. 2015	End Dec. 2015	End Mar. 2016
Consensus Mean Average:	0.73%	0.67%	0.71%	0.77%
Mode (most frequent forecast):	0.75%	0.75%	0.75%	0.75%

Direction of Trade – 2013

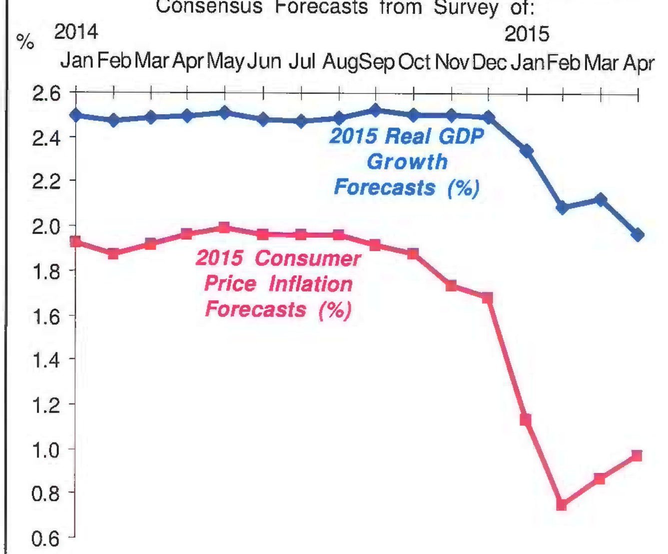
Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
United States	75.8	United States	52.1
China	4.3	China	11.1
United Kingdom	3.0	Mexico	5.6
EU	*7.0*	*Asia (ex. Japan)*	*14.2*
Asia (ex. Japan)	*6.1*	*EU*	*11.2*
Latin America	*2.8*	*Latin America*	*9.0*

Real Growth and Inflation

(% change over previous year)

2015 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



The EURO ZONE is: Austria, Belgium, Cyprus, Estonia, Finland, France, Germany, Greece, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Portugal, Slovakia, Slovenia and Spain.	Average % Change on Previous Calendar Year																Year Average	
	Gross Domestic Product		Private Consumption		Govt Consumption		Gross Fixed Investment		Industrial Production		Consumer Prices (HICP)		Industrial Producer Prices		Hourly Labour Costs – Total		Unemployment Rate (%)	
Economic Forecasters	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
Bank Julius Baer	1.8	2.0	1.9	2.1	0.5	0.4	2.2	3.4	1.5	2.5	0.5	1.3	-1.5	-1.3	2.1	1.7	11.3	11.2
BNP Paribas	1.8	2.0	1.8	1.1	0.6	0.8	1.2	2.2	1.5	3.6	0.0	1.3	na	na	na	na	10.8	10.1
JP Morgan	1.7	2.5	2.1	2.2	0.9	1.2	1.9	3.5	1.8	3.2	0.1	1.0	na	na	na	na	10.9	10.1
Natixis	1.7	1.7	1.8	1.5	0.8	0.8	2.1	2.8	2.1	2.7	0.3	1.3	na	na	na	na	11.0	10.7
European F'cast Network	1.6	2.1	1.6	1.2	0.6	0.6	2.4	4.4	2.1	1.6	0.1	1.3	na	na	1.5	2.3	11.1	10.6
IHS Economics	1.6	1.9	2.0	1.7	0.7	0.9	2.4	3.3	1.5	2.3	0.0	1.3	-1.5	1.1	1.5	1.8	11.0	10.6
UBS	1.6	2.0	1.5	1.6	0.7	0.7	2.1	3.6	na	na	0.1	1.5	0.1	1.4	na	na	11.0	10.6
Oxford Economics	1.6	1.8	1.7	1.5	0.3	0.4	1.0	2.9	1.5	2.3	0.1	1.3	-1.0	1.6	na	na	11.0	10.6
Intesa Sanpaolo	1.5	2.0	1.7	1.7	0.6	0.5	2.0	2.6	2.4	1.5	0.3	1.3	-1.2	0.6	1.5	1.4	11.1	10.5
Allianz	1.5	1.6	1.8	1.4	1.1	1.0	1.7	2.8	1.5	2.2	0.1	1.2	-1.0	2.0	na	na	11.0	10.5
AXA Investment Managers	1.5	1.5	1.7	1.3	0.7	0.6	1.6	1.2	na	na	-0.1	1.2	na	na	na	na	na	na
Barclays Capital	1.5	1.7	1.6	1.3	0.7	0.7	1.4	2.6	na	na	0.2	1.1	na	na	na	na	11.2	10.7
Credit Suisse	1.5	2.1	1.7	1.6	na	na	1.9	4.0	2.6	3.2	0.0	1.2	na	na	na	na	11.2	10.6
Citigroup	1.5	2.0	1.8	1.6	1.0	0.7	1.5	3.0	1.8	3.6	0.2	1.5	na	na	na	na	10.7	9.9
Bank of America - Merrill	1.5	1.6	1.8	1.7	0.3	0.1	1.6	2.5	1.2	2.2	-0.1	1.1	na	na	na	na	11.2	10.9
Goldman Sachs	1.5	1.7	1.7	1.8	na	na	1.0	2.5	1.8	2.6	0.0	1.2	na	na	na	na	11.6	11.2
Grupo Santander	1.5	1.8	1.5	1.3	0.3	0.3	3.0	4.3	na	na	-0.1	1.2	na	na	na	na	11.2	10.9
Morgan Stanley	1.4	2.2	1.7	1.6	0.5	0.7	1.9	3.8	na	na	0.2	1.6	na	na	na	na	10.9	10.3
Societe Generale	1.4	1.6	1.7	1.3	1.0	1.0	-0.4	2.0	na	na	0.0	1.3	na	na	na	na	11.2	10.7
Credit Agricole	1.4	1.6	1.5	1.5	0.8	0.3	1.3	2.3	na	na	0.1	1.2	na	na	na	na	11.4	10.9
ETLA	1.4	1.9	1.7	1.4	0.8	0.5	1.6	2.7	1.6	2.0	0.3	1.3	na	na	na	na	11.1	10.4
Econ Intelligence Unit	1.3	1.5	1.4	1.1	0.9	0.9	1.6	2.7	1.6	2.1	-0.2	0.9	-1.4	1.3	na	na	11.1	10.7
BBVA	1.3	2.2	1.4	1.7	0.5	0.9	0.9	4.6	na	na	0.1	1.0	na	na	na	na	11.2	10.6
HSBC	1.3	1.4	1.7	1.3	1.1	0.8	1.4	2.0	1.6	2.1	-0.1	0.8	na	na	1.4	1.3	11.1	10.8
Moody's Analytics	1.3	1.8	1.5	1.6	0.6	0.6	1.4	3.0	0.1	2.0	0.2	1.3	-1.0	2.4	na	na	11.7	11.2
Nomura	1.2	1.1	1.6	1.2	0.6	0.7	1.1	1.4	na	na	0.1	0.7	na	na	na	na	11.3	11.2
Commerzbank	1.2	1.3	1.3	1.5	1.1	0.7	1.4	2.2	0.9	2.1	-0.1	1.2	-1.7	1.1	1.4	1.6	11.2	10.7
Consensus (Mean)	1.5	1.8	1.7	1.5	0.7	0.7	1.6	2.9	1.6	2.4	0.1	1.2	-1.1	1.1	1.6	1.7	11.1	10.7
Last Month's Mean	1.4	1.7	1.6	1.4	0.7	0.7	1.5	2.7	1.3	2.3	0.0	1.2	-1.0	1.2	1.5	1.7	11.2	10.8
3 Months Ago	1.1	1.6	1.3	1.3	0.7	0.7	1.3	2.6	1.3	2.2	0.1	1.2	-0.2	1.2	1.4	1.7	11.3	10.9
High	1.8	2.5	2.1	2.2	1.1	1.2	3.0	4.6	2.6	3.6	0.5	1.6	0.1	2.4	2.1	2.3	11.7	11.2
Low	1.2	1.1	1.3	1.1	0.3	0.1	-0.4	1.2	0.1	1.5	-0.2	0.7	-1.7	-1.3	1.4	1.3	10.7	9.9
Standard Deviation	0.2	0.3	0.2	0.3	0.2	0.3	0.6	0.9	0.5	0.6	0.2	0.2	0.5	1.1	0.3	0.4	0.2	0.3
Comparison Forecasts																		
Eur Commission (Jan. '15)	1.3	1.9	1.6	1.6	0.4	0.9	2.0	4.4			-0.1	1.3					11.2	10.6
ECB - midpoint (Dec. '14)	1.0	1.5	1.3	1.2	0.5	0.4	1.4	3.2			0.7	1.3					11.2	10.9
IMF (Apr. '15)	1.5	1.6	1.7	1.5	0.7	0.5	1.5	2.4			0.1	1.0					11.1	10.6
OECD (Nov. '14)	1.1	1.7	1.0	1.3	0.4	0.6	1.2	3.1			1.1						11.4	

European Monetary Union

Euro zone - The 19 European countries (listed at the top of this page) are united by a common currency (the euro), monetary policy and adherence to the Maastricht Treaty. **Monetary Policy** - is set by the European Central Bank's (ECB) governing board, headed by Mario Draghi. **Nominal GDP** - Euro 9,585bn (2013). **Population** - 331.1mn (mid-year, 2013). **$/Euro Exchange Rate** - 1.328 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***March 9, 2015***

	2014		2015				2016			
	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Gross Domestic Product	0.8	0.9	***1.0***	***1.3***	***1.6***	***1.7***	***1.7***	***1.7***	***1.7***	***1.6***
Private Consumption	1.1	1.4	***1.6***	***1.7***	***1.6***	***1.6***	***1.5***	***1.5***	***1.5***	***1.5***
Consumer Prices	0.4	0.2	***-0.3***	***-0.1***	***0.1***	***0.5***	***1.1***	***1.1***	***1.2***	***1.2***

Percentage Change (year-on-year).

Historical Data

** % change on previous year*	2011	2012	2013	2014
Gross Domestic Product*	1.7	-0.7	-0.4	0.9
Private Consumption*	0.2	-1.3	-0.6	1.0
Government Consumption*	-0.2	-0.1	0.2	0.7
Gross Fixed Capital Formation*	1.7	-3.5	-2.4	1.0
Industrial Production*	3.5	-2.4	-0.7	0.8
Consumer Prices*	2.7	2.5	1.3	0.4
Industrial Producer Prices*	5.7	2.8	-0.2	-1.5
Hourly Labour Costs – Total*	2.6	2.4	1.3	1.2
Unemployment Rate, (%)	10.2	11.4	12.0	11.6
Exports - Goods & Services*	6.8	2.7	2.2	3.7
Imports - Goods & Services*	4.5	-0.9	1.4	3.8
Current Account, Euro bn	-6.9	151	214	236
General Govt. Budget Balance (Maastricht definition), Euro bn	-402	-355	-285	-261 *e*
Money Supply, M3, end period*	1.6	3.5	1.0	3.6

e = consensus estimate based on latest survey

Average % Change on Previous Calendar Year				Annual Total				Average % Change on Prev. Year	
Exports of Goods & Services		Imports of Goods & Services		Current Account (€ bn)		General Govt Budget Balance (Maastricht) (€ bn)		Money Supply, M3, end period	
2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
6.7	5.2	5.5	8.5	na	na	na	na	na	na
6.1	8.1	5.6	7.1	370	410	-198	-168	na	na
3.9	5.0	4.5	5.6	na	na	na	na	na	na
4.4	3.9	4.0	4.0	240	220	na	na	na	na
6.0	7.7	6.0	7.6	na	na	na	na	na	na
4.8	4.5	4.8	4.4	240	245	-217	-184	na	na
4.0	4.4	4.2	4.9	na	na	na	na	na	na
4.2	4.4	3.8	4.7	280	263	-203	-172	4.1	4.0
4.6	4.3	5.2	5.0	247	275	-218	-235	3.7	4.6
4.3	4.2	4.6	4.4	265	245	-200	-195	na	na
3.9	4.1	3.8	3.6	na	na	na	na	na	na
na	na	na	na	na	na	na	na	na	na
na	na	na	na	na	na	-232	-197	na	na
3.8	4.0	4.0	3.7	232	218	-213	-180	na	na
7.4	3.9	7.3	3.8	248	248	-234	-228	na	na
na	na	na	na	na	na	na	na	na	na
4.4	4.4	4.2	4.4	188	180	-202	-152	na	na
4.5	5.2	3.9	4.8	247	249	-209	-199	na	na
3.9	3.8	3.7	3.7	na	na	na	na	na	na
4.5	4.9	4.2	4.8	255	251	-243	-206	na	na
7.0	5.6	6.4	5.1	na	na	na	na	na	na
3.3	3.7	3.3	3.6	na	na	-228	-178	na	na
4.8	4.9	4.8	5.0	na	na	na	na	na	na
3.9	3.8	4.1	4.0	245	250	-239	-217	na	na
3.2	4.1	3.3	3.9	-8	-8	na	na	5.7	3.4
3.6	3.1	3.4	3.4	na	na	na	na	na	na
4.4	5.4	3.9	4.9	250	200	-250	-230	4.0	4.0
4.6	4.7	4.5	4.8	236	232	-220	-196	4.4	4.0
4.5	4.4	4.4	4.5	232	226	-229	-200	4.3	3.9
4.1	4.3	4.3	4.4	237	233	-229	-201	2.8	3.2
7.4	8.1	7.3	8.5	370	410	-198	-152	5.7	4.6
3.2	3.1	3.3	3.4	-8	-8	-250	-235	3.7	3.4
1.1	1.2	1.0	1.3	80	87	17	25	0.9	0.5
4.3	5.1	4.5	5.7	329	325				

Euro Zone Economic Statistics

The source of all Historical Data (facing page) is **Eurostat**, with the exception of the Current Account and the Money Supply, M3, which are from the **European Central Bank**. The base years and statistics methodologies used by Eurostat may differ from those used by individual Euro zone-member countries included in *Consensus Forecasts*. Eurostat data is often drawn from the national statistical agencies within the Euro zone but is adjusted to achieve standard classifications.

Q1 Started on Upbeat Note

The GDP outlook for the Euro area has continued to brighten modestly. March PMIs, not just regionally but also country-wide, continued to improve for both services and manufacturing (with a few exceptions, like France). Strong consumer spending in Germany is helping to support European consumption fundamentals as well, although Euro area retail sales slipped by -0.2% (m-o-m) in volume terms in February. Y-o-y, though, they stood at a solid 3.0%. Spending activity is being helped somewhat by ebbing unemployment growth, increased bank lending and the sharp decline in petrol prices. Our panel's consumption forecast for 2015 has edged up this month. Industry has been noticeably upgraded, in line with a 1.1% (m-o-m) surge in February production.

Euro Zone Interest Rates

Forecasts are provided by a total of more than 80 panellists for **Germany** (page 9), **France** (page 11), **Italy** (page 15), the **Netherlands** (page 20) and **Spain** (page 22). This allows the analysis of forecasts for different yields on individual country 10-year benchmark bonds. Forecasts for 3-month interest rates are all for the EURIBOR rate.

	Actual	---- Consensus -----	
	Apr. 13, '15	*End Jul. '15*	*End Apr. '16*
Euribor, 3-mth, %	0.0	0.0	0.0
German 10-yr Govt Bond, %	0.2	0.3	0.6

Euro zone Refinancing Rate – Apr. 13, 2015 = 0.05%

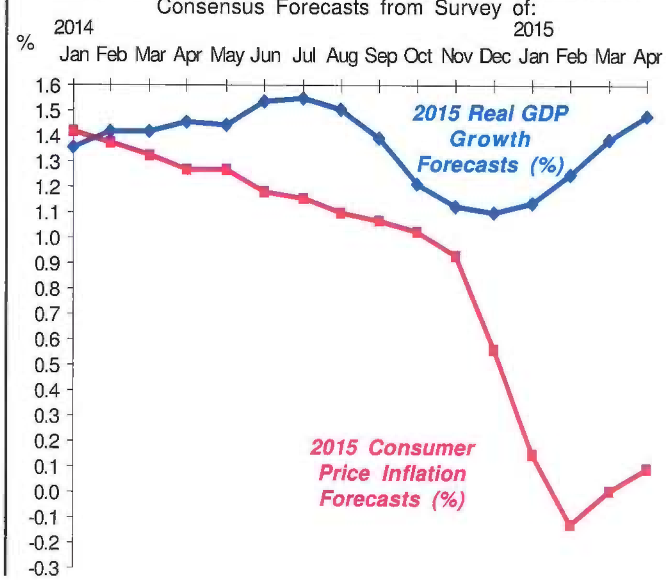
FORECASTS	End Jun. 2015	End Sep. 2015	End Dec. 2015	End Mar. 2016
Consensus Mean Average:	0.05%	0.05%	0.05%	0.07%
Mode (most frequent forecast):	0.05%	0.05%	0.05%	0.05%

Euro Exchange Rates

Consensus forecasts from a survey of approximately 100 panellists are shown on page 27.

2015 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



	Average % Change on Previous Calendar Year												Annual Total				Rates on Survey Date			
	Gross Domestic Product		Private Con-sumption		Gross Fixed Investment		Manufac-turing Produc-tion		Con-sumer Prices		Hourly Wages (Manu-facturing)		Current Account (€ bn)		General Govt Bud Bal (Maastricht) (€ bn)		3 month Euro Rate (%) 0.0%		10 Year Dutch Govt Bond Yield (%) 0.3%	
Economic Forecasters	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	End Jul'15	End Apr'16	End Jul'15	End Apr'16
Credit Suisse	2.0	2.0	1.0	1.4	4.9	5.0	na	na	na	na	na	na	na	na	-13.4	-12.4	na	na	na	na
ING	2.0	2.1	1.2	1.2	5.8	3.9	1.0	1.5	0.3	2.0	1.7	2.0	71.3	73.3	-10.1	-5.6	0.0	0.1	0.2	0.7
ABN AMRO	1.8	2.3	1.5	1.5	4.5	5.1	na	na	0.6	1.8	2.0	2.3	66.5	66.5	-11.5	-7.0	0.1	0.1	0.1	0.5
NIBC	1.8	0.3	1.4	0.9	4.0	0.0	1.6	-1.0	0.5	0.8	1.8	1.5	65.0	55.0	-12.0	-20.0	0.0	0.0	0.8	1.0
Theodoor Gilissen	1.8	1.7	1.5	1.7	5.8	2.9	1.3	3.1	0.5	1.1	1.1	2.1	na	na	-13.0	-10.0	0.0	0.0	0.3	0.4
UBS	1.8	2.0	0.8	0.9	4.7	5.3	na	na	na	na	na	na	na	na	na	na	-0.1	-0.1	0.8	1.5
Feri EuroRating	1.7	1.7	1.1	0.9	1.0	1.7	2.0	1.8	0.1	1.5	1.6	2.0	74.0	67.8	-14.6	-12.4	0.0	0.1	0.5	1.0
Rabobank Nederland	1.7	1.8	1.4	1.3	4.7	3.4	na	na	na	na	na	na	69.6	67.7	-14.9	-13.8	0.0	0.0	0.5	1.0
Bank of America - Merrill	1.6	1.8	1.3	1.5	3.4	3.7	2.0	2.8	1.0	1.1	na	na	69.6	72.3	-12.4	-12.8	na	na	na	na
Barclays Capital	1.6	1.7	1.0	1.5	2.2	3.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na
Nomura	1.6	1.1	1.2	0.8	4.8	0.4	na	na	na	na	na	na	na	na	na	na	0.0	0.0	na	na
Moody's Analytics	1.5	1.7	1.6	1.8	1.3	2.8	1.6	2.0	0.7	1.4	na	na	75.9	76.0	na	na	0.0	0.0	0.6	0.7
BNP Paribas	1.5	1.7	1.3	1.7	4.0	4.0	2.1	2.6	0.0	1.2	2.3	2.4	69.7	70.1	-12.0	-11.0	0.0	0.0	0.3	1.4
Citigroup	1.4	1.9	1.1	1.0	2.9	2.3	na	na	na	na	na	na	59.3	53.4	-13.2	-12.0	0.1	0.1	0.0	0.4
Oxford Economics	1.3	1.4	0.6	0.8	1.3	2.1	1.9	1.3	0.6	1.3	0.8	1.8	72.1	74.6	-12.7	-11.8	0.0	0.0	0.2	0.2
Econ Intelligence Unit	1.3	1.5	1.1	0.7	2.5	2.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na
Consensus (Mean)	1.6	1.7	1.2	1.2	3.6	3.0	1.7	1.8	0.5	1.4	1.6	2.0	69.3	67.7	-12.7	-11.7	0.0	0.0	0.4	0.8
Last Month's Mean	1.5	1.5	1.0	1.2	3.0	2.8	1.8	1.8	0.5	1.2	1.7	2.0	67.5	66.4	-12.5	-12.0				
3 Months Ago	1.3	1.5	0.8	1.1	2.3	2.5	2.1	1.6	0.9	1.4	1.9	2.0	70.3	69.6	-13.1	-12.7				
High	2.0	2.3	1.6	1.8	5.8	5.3	2.1	3.1	1.0	2.0	2.3	2.4	75.9	76.0	-10.1	-5.6	0.1	0.1	0.8	1.5
Low	1.3	0.3	0.6	0.7	1.0	0.0	1.0	-1.0	0.0	0.8	0.8	1.5	59.3	53.4	-14.9	-20.0	-0.1	-0.1	0.0	0.2
Standard Deviation	0.2	0.5	0.3	0.4	1.6	1.5	0.4	1.3	0.3	0.4	0.5	0.3	4.8	7.8	1.4	3.7	0.0	0.0	0.3	0.4
Comparison Forecasts																				
CPB (Mar. '15)	1.7	1.8	1.5	1.7	3.4	3.9			0.4	1.2			67.1	65.6	-12.3	-8.1				
Eur Commission (Jan. '15)	1.4	1.7	1.2	1.6	3.0	4.0							53.3	55.5						
IMF (Apr. '15)	1.6	1.6													-9.4	-3.5				
OECD (Nov. '14)	1.4	1.6	0.4	0.4	3.5	4.3														

◈ Q4 GDP growth was revised to 0.8% (q-o-q) so annual growth in 2014 edged up to 0.9%, led by a better-than-expected increase in gross fixed investment. The CBS's consumer confidence index moved into positive territory in March for the first time in over seven years. This reflects buoyant household consumption in January, which expanded by 1.8% (y-o-y), whilst retail sales rose by 3.1% (y-o-y) in February.

◈ Meanwhile, Dutch exports grew at their fastest pace in four years, surging by 10.2% (y-o-y). The 2015 GDP outlook has advanced to 1.6% this month.

Real Growth and Inflation

(% change over previous year)

Historical Data

* % change on previous year	2011	2012	2013	2014
Gross Domestic Product*	1.7	-1.6	-0.7	0.9
Private Consumption*	0.2	-1.4	-1.6	0.1
Gross Fixed Investment*	5.6	-6.0	-4.0	3.4
Manufacturing Production*	3.3	-0.8	-1.0	1.1
Consumer Prices*	2.4	2.4	2.5	1.0
Hourly Wages (manufacturing)*	1.2	1.8	1.6	1.7 e
Current Account, transactions basis, Euro bn	56.8	70.5	70.4	67.5
General Govt. Budget Balance (Maastricht definition), Euro bn	-27.8	-25.3	-14.6	-12.4 e
3 mth Euro, % (end yr)	1.4	0.2	0.3	0.1
10 Yr Dutch Govt Bond Yield, % (end yr)	2.2	1.5	2.2	0.7

e = consensus estimate based on latest survey

Nominal GDP - Euro 603.4bn (2013). **Popn** - 16.8mn (mid-year, 2013). **$/Euro Exch. Rate** - 1.328 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***March 9, 2015***

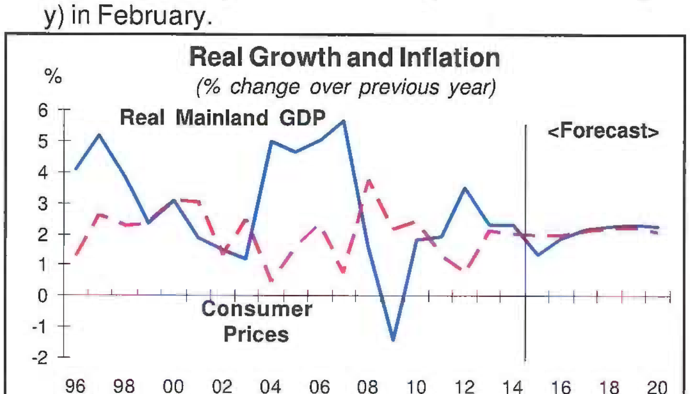
	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4
Gross Domestic Product	1.0	1.0	***1.6***	***1.3***	***1.5***	***1.5***	***1.5***	***1.5***	***1.7***	***1.6***
Consumer Prices	0.9	0.9	***0.2***	***0.2***	***0.4***	***0.8***	***1.2***	***1.2***	***1.0***	***0.9***

Percentage Change (year-on-year)

	Average % Change on Previous Calendar Year												Annual Total				Rates on Survey Date			
	Gross Domestic Product (Mainland)		Private Consumption		Gross Fixed Investment		Manufacturing Production		Consumer Prices		Wages & Salaries		Current Account (Nkr bn)		General Govt Budget Balance (Nkr bn)		1.5% 3 month Interbank Rate (%)		1.3% 10 Year Govt Bond Yield (%)	
Economic Forecasters	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	End Jul'15	End Apr'16	End Jul'15	End Apr'16
HSBC	1.7	2.0	1.9	1.7	-2.3	3.7	1.8	2.5	1.6	1.7	2.4	2.0	na	na	na	na	1.0	1.0	1.4	1.6
Citigroup	1.6	1.8	1.8	1.8	-2.4	0.5	na	na	2.4	2.3	na	na	261	269	na	na	0.8	0.8	na	na
Nordea Markets	1.5	1.7	2.0	1.5	-4.0	-0.7	na	na	2.3	2.0	2.8	2.8	176	276	219	277	1.3	1.0	1.4	1.5
Feri EuroRating	1.4	2.2	2.1	2.6	-1.0	3.1	2.7	2.0	1.5	1.7	3.3	3.7	254	276	278	256	1.2	1.2	1.6	2.1
NHO Conf Nor Enterprise	1.3	2.3	1.8	2.3	-5.3	-1.5	na	na	na	na	na	na	na	na	na	na	na	na	na	na
DNB	1.2	1.7	1.9	2.2	-4.3	-1.6	1.8	-0.4	2.6	2.1	3.1	2.9	na	na	na	na	1.5	1.1	1.6	1.9
Swedbank	1.2	1.4	1.7	1.2	-3.3	-3.6	-0.8	0.1	2.3	1.8	2.5	2.3	290	340	202	176	na	na	na	1.5
Statistics Norway	1.2	2.2	2.1	2.2	-3.6	1.1	na	na	2.3	2.0	2.9	3.1	162	171	na	na	1.0	1.0	na	na
UBS	1.1	2.2	2.0	2.8	-3.9	0.9	na	na	1.3	1.3	na	na	na	na	na	na	1.0	1.0	1.7	2.5
Oxford Economics	0.6	1.3	1.9	2.2	-2.3	2.4	-3.2	-1.6	1.8	2.7	2.3	2.7	183	230	190	176	1.2	1.2	1.5	1.5
Consensus (Mean)	1.3	1.9	1.9	2.0	-3.2	0.4	0.5	0.5	2.0	2.0	2.8	2.8	221	260	222	221	1.1	1.0	1.5	1.8
Last Month's Mean	1.3	2.0	1.8	2.1	-2.2	0.6	0.2	0.0	2.2	2.2	2.9	3.0	243	286	222	221				
3 Months Ago	1.6	2.1	2.1	2.7	0.1	1.5	0.5	1.1	2.2	2.3	3.3	3.3	246	282	217	235				
High	1.7	2.3	2.1	2.8	-1.0	3.7	2.7	2.5	2.6	2.7	3.3	3.7	290	340	278	277	1.5	1.2	1.7	2.5
Low	0.6	1.3	1.7	1.2	-5.3	-3.6	-3.2	-1.6	1.3	1.3	2.3	2.0	162	171	190	176	0.8	0.8	1.4	1.5
Standard Deviation	0.3	0.3	0.2	0.5	1.2	2.3	2.4	1.7	0.5	0.4	0.4	0.5	53	56	39	53	0.2	0.2	0.1	0.4
Comparison Forecasts																				
Bank of Norway (Mar. '15)	1.5	2.0	1.8	2.5					2.3	2.3										
OECD (Nov. '14)	1.8	2.5	3.0	3.0	0.5	2.5			2.1											

◈ The key policy rate was surprisingly kept at 1.25% in the central bank's March meeting. With oil prices not improving, the bank has already signalled possible rate decreases later this year to support stalling GDP growth. Inflation was 2% (y-o-y) in March, close to the 2.5% target, lowering the immediate urgency for the bank to intervene.

◈ Household consumption rebounded from January's -0.4% (m-o-m) decline to a +0.9% jump in February. However, concerns have ignited over soaring household debt, fuelled by cheap credit, as house prices rose 8.7% (y-o-y) in February.



Historical Data

* % change on previous year	2011	2012	2013	2014
GDP (Mainland)*	1.9	3.5	2.3	2.3
Private Consumption*	2.2	3.4	2.1	2.2
Gross Fixed Investment*	7.4	7.5	6.9	1.2
Manufacturing Production*	0.9	2.8	3.7	3.3
Consumer Prices*	1.3	0.7	2.1	2.0
Wages & Salaries per Full-Time Employee (Total)*	4.1	4.2	4.8	2.8
Current Account, Nkr bn	345	369	308	267
General Govt. Bud Bal, Nkr bn	375	411	348	285
3 mth Interbank Rate, % (end year)	2.9	1.8	1.7	1.5
10 Yr Govt Bond Yield, % (end year)	2.4	2.1	3.0	1.6

Nominal GDP (total) - Nkr 3,011bn (2013). **Population** - 5.0mn (mid-yr, 2013). **Nkr/$ Exchange Rate** - 5.875 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***March 9, 2015***

	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4
Gross Domestic Product (Mainland)	2.2	2.2	***1.9***	***1.1***	***1.0***	***1.2***	***1.4***	***1.8***	***2.1***	***2.2***
Consumer Prices	2.2	2.0	***2.3***	***2.4***	***2.0***	***2.4***	***2.3***	***2.1***	***1.9***	***1.8***

Percentage Change (year-on-year)

	Average % Change on Previous Calendar Year												Annual Total				Rates on Survey Date			
	Gross Domestic Product		House-hold Con-sumption		Gross Fixed Invest-ment		Industrial Produc-tion		Con-sumer Prices		Salary Cost per Hour		Current Account (€ bn)		General Govt Bud Bal (Maastricht) (€ bn)		0.0% 3 month Euro Rate (%)		1.3% 10 Year Spanish Govt Bond Yield (%)	
Economic Forecasters	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	End Jul'15	End Apr'16	End Jul'15	End Apr'16
FUNCAS	3.0	2.8	3.5	2.9	6.6	5.6	1.2	3.3	-0.7	0.8	na	na	8.4	5.1	-48.1	-37.0	0.0	0.1	1.1	1.0
CEOE	2.8	2.6	3.1	2.5	5.5	4.4	2.0	1.5	-0.3	1.4	na	na	6.5	10.2	-47.0	-39.7	0.0	0.0	1.1	0.9
Inst Estud Economicos	2.8	2.8	3.2	3.1	7.9	8.1	1.9	2.2	-0.4	1.0	0.5	1.0	na	na	na	na	0.1	0.2	1.4	1.7
Barclays Capital	2.7	2.4	2.3	1.8	3.7	4.3	na	na	-0.3	1.1	na	na	na	na	na	na	na	na	na	na
BBVA	2.7	2.7	2.5	1.7	5.2	6.4	na	na	-0.4	1.4	na	na	9.9	11.1	-46.1	-32.6	0.0	0.1	1.0	1.6
IFL-Univers Carlos III	2.7	2.5	3.0	2.7	3.4	4.3	1.9	3.6	-0.4	0.9	na	na	na	na	na	na	na	na	na	na
Grupo Santander	2.6	2.5	3.4	3.0	5.2	4.6	na	na	-0.7	0.6	0.4	1.0	17.6	16.4	-45.2	-32.0	0.1	0.1	1.6	2.2
Inst. Klein-G. (UAM)	2.6	3.0	2.8	3.0	5.0	5.4	2.5	2.9	-0.4	1.3	0.3	0.7	9.2	6.5	-52.3	-42.6	0.1	0.1	1.4	1.7
AFI	2.5	2.2	3.1	2.3	4.9	4.5	na	na	-0.8	1.1	na	na	12.7	10.6	-46.8	-44.8	0.1	0.1	1.3	1.8
Citigroup	2.5	2.5	3.3	2.4	5.3	5.3	na	na	-0.4	0.8	na	na	2.9	3.3	-48.2	-35.2	0.1	0.1	1.0	1.0
Oxford Economics	2.5	2.5	2.8	2.7	4.3	3.9	2.4	4.4	-0.3	1.1	1.1	0.3	5.8	4.2	-47.2	-36.9	0.0	0.0	1.2	1.2
Econ Intelligence Unit	2.5	2.0	3.1	2.1	3.5	3.2	2.1	2.2	-0.8	1.3	na	na	2.6	-3.9	na	na	na	na	na	na
La Caixa	2.5	2.3	2.6	1.6	4.6	4.2	2.4	2.8	-0.1	1.9	0.1	1.2	14.1	14.8	-52.1	-37.5	0.1	0.1	0.9	1.2
UBS	2.4	2.3	2.8	2.7	4.4	3.9	na	na	-0.4	1.4	na	na	na	na	na	na	-0.1	-0.1	na	na
CEPREDE	2.3	2.5	2.4	2.7	4.0	5.1	2.5	3.0	-0.3	1.4	0.4	1.7	16.0	10.0	-51.8	-41.6	0.0	0.1	1.3	1.6
Bank of America - Merrill	2.2	1.9	2.8	2.3	3.9	2.1	1.6	1.8	-0.7	1.0	na	na	7.9	9.4	-50.8	-41.9	na	na	na	na
Goldman Sachs	2.2	2.1	2.6	2.9	3.3	3.9	1.0	1.1	-0.7	1.1	na	na	na	na	na	na	na	na	na	na
HSBC	2.1	1.8	3.5	2.5	3.2	2.1	1.0	1.4	-0.6	1.1	0.9	1.1	4.4	2.4	-54.5	-46.0	0.1	0.1	1.2	1.9
Consensus (Mean)	2.5	2.4	2.9	2.5	4.7	4.5	1.9	2.5	-0.5	1.2	0.5	1.0	9.1	7.7	-49.2	-39.0	0.0	0.1	1.2	1.5
Last Month's Mean	2.4	2.3	2.8	2.3	4.0	4.1	2.1	2.5	-0.6	1.2	0.6	0.9	7.2	6.6	-49.4	-39.6				
3 Months Ago	2.0	2.1	2.3	2.2	3.5	3.5	2.0	2.4	-0.3	1.0	0.4	1.2	9.0	8.3	-49.6	-41.4				
High	3.0	3.0	3.5	3.1	7.9	8.1	2.5	4.4	-0.1	1.9	1.1	1.7	17.6	16.4	-45.2	-32.0	0.1	0.2	1.6	2.2
Low	2.1	1.8	2.3	1.6	3.2	2.1	1.0	1.1	-0.8	0.6	0.1	0.3	2.6	-3.9	-54.5	-46.0	-0.1	-0.1	0.9	0.9
Standard Deviation	0.2	0.3	0.4	0.5	1.2	1.4	0.5	1.0	0.2	0.3	0.3	0.4	4.8	5.5	3.0	4.5	0.0	0.1	0.2	0.4
Comparison Forecasts																				
Banco de Espana (Mar. '15)	2.8	2.7	3.3	2.4	5.9	6.7			-0.2	1.2										
Eur Commission (Jan. '15)	2.3	2.5	2.7	2.6	4.7	5.2			-1.0	1.1			7.0	5.6						
IMF (Apr. '15)	2.5	2.0	3.9	2.5	4.5	3.1			-0.7	0.7					-46.7	-31.7				
OECD (Nov. '14)	1.7	1.9	1.9	1.7	3.6	4.9			0.5											

◈ The consensus for Spanish GDP output in 2015 has edged up to 2.5% in further sign that the economic recovery is well underway. New job creation is slowly reducing the still-high unemployment rate, which fell to 23.2% in February. CPI inflation remains negative, despite lifting to -0.7% (y-o-y) in March amid higher transport costs. This should continue to fuel the boom in domestic demand which is driving the economy's resurgence.

◈ Industrial production rose 0.7% (m-o-m) in February, its biggest expansion since April last year, boosted by rising demand for durable consumer goods.

Real Growth and Inflation

(% change over previous year)

Historical Data

** % change on previous year*	2011	2012	2013	2014
Gross Domestic Product*	-0.6	-2.1	-1.2	1.4
Household Consumption*	-2.0	-3.0	-2.3	2.4
Gross Fixed Investment*	-6.3	-8.1	-3.8	3.4
Industrial Production*	-2.0	-6.4	-1.7	1.4
Consumer Prices*	3.2	2.4	1.4	-0.2
Salary Cost per Hour*	2.1	0.0	0.4	0.3
Current Account, Euro bn	-34.0	-3.0	15.1	1.2
General Govt. Budget Balance (Maastricht definition), Euro bn	-101	-109	-71.3	-60.4 *e*
3 mth Euro, % (end yr)	1.4	0.2	0.3	0.1
10 Yr Spanish Govt Bond Yield, % (end yr)	5.1	5.3	4.1	1.6

e = consensus estimate based on latest survey

Nominal GDP - Euro1,023bn (2013). **Popn** - 46.9mn (mid-year, 2013). **$/Euro Exch. Rate** - 1.328 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***March 9, 2015***

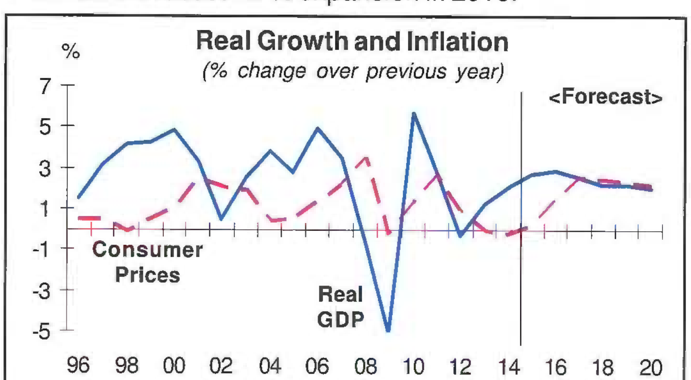
	2014		2015				2016			
	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Gross Domestic Product	1.6	2.0	***2.3***	***2.4***	***2.5***	***2.4***	***2.3***	***2.3***	***2.2***	***2.1***
Consumer Prices	-0.3	-0.5	***-1.2***	***-0.9***	***-0.6***	***0.1***	***1.3***	***1.2***	***1.2***	***1.2***

Percentage Change (year-on-year)

	Average % Change on Previous Calendar Year												Annual Total				Rates on Survey Date			
	Gross Domestic Product		Household Consumption		Gross Fixed Investment		Mining & Manufacturing Production		Consumer Prices		Hourly Earnings (Mining & Manuf.)		Current Account (Skr bn)		General Govt Budget Balance (Skr bn)		3 month Interbank Rate (%) -0.1%		10 Year Govt Bond Yield (%) 0.3%	
Economic Forecasters	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	End Jul'15	End Apr'16	End Jul'15	End Apr'16
Goldman Sachs	3.2	3.6	3.4	4.4	6.0	4.5	na	na	0.2	1.4	na	na	na	na	na	na	na	na	na	na
Confed of Swed Enterprise	3.1	na	3.3	na	3.8	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na
National Institute - NIER	3.1	3.3	2.8	2.7	4.1	5.5	1.7	4.8	0.2	1.1	2.9	3.2	247	267	-60.0	-37.0	na	na	0.9	1.5
UBS	3.0	3.7	2.6	3.1	7.1	7.7	na	na	0.2	1.5	na	na	na	na	na	na	0.0	0.0	1.1	1.5
Econ Intelligence Unit	2.9	3.1	2.6	2.4	5.5	4.1	1.8	3.1	0.6	1.8	na	na	254	232	na	na	na	na	na	na
SBAB Bank	2.9	2.7	2.4	2.3	6.8	4.3	2.0	4.0	0.2	1.5	2.5	2.7	220	200	-75.0	-75.0	-0.1	-0.1	0.4	0.9
Nordea	2.9	2.6	2.5	2.4	na	na	na	na	0.3	1.3	na	na	246	165	-71.5	-44.8	-0.4	-0.4	0.6	1.4
Citigroup	2.8	2.6	2.8	2.7	4.2	4.0	na	na	0.1	1.3	na	na	247	250	-74.3	-42.0	-0.5	-0.5	0.2	0.7
SE Banken	2.7	2.7	2.8	2.7	4.7	5.5	na	na	0.1	1.1	2.8	3.0	na	na	na	na	-0.3	-0.3	0.2	0.7
Morgan Stanley	2.7	3.0	2.2	2.5	5.9	5.0	na	na	0.5	1.6	na	na	234	249	na	na	na	na	na	na
Erik Penser Bank	2.5	2.2	2.6	1.7	5.0	5.5	na	na	0.4	2.0	3.0	3.0	210	200	-60.0	-60.0	0.0	0.0	0.5	0.8
Swedbank	2.2	2.9	2.7	2.3	5.3	6.3	1.0	4.2	0.4	1.6	3.0	3.3	200	210	-70.0	-55.0	-0.3	-0.3	0.2	1.2
Oxford Economics	2.0	2.8	3.0	3.5	3.4	5.3	1.2	3.4	0.2	1.8	na	2.3	213	177	-83.2	-52.3	-0.4	-0.4	0.6	1.1
HSBC	1.8	1.9	2.4	2.2	4.9	4.2	1.0	1.2	0.1	0.4	2.3	2.0	na	na	na	na	0.0	0.0	0.9	1.1
Consensus (Mean)	2.7	2.9	2.7	2.7	5.1	5.2	1.4	3.4	0.3	1.4	2.8	2.8	230	217	-70.6	-52.3	-0.2	-0.2	0.6	1.1
Last Month's Mean	2.6	2.8	2.8	2.7	4.7	5.0	1.8	3.6	0.3	1.6	2.7	2.8	215	215	-71.2	-49.4				
3 Months Ago	2.4	2.7	2.7	2.6	4.5	4.9	1.7	3.4	0.4	1.7	2.8	2.7	211	210	-65.0	-41.0				
High	3.2	3.7	3.4	4.4	7.1	7.7	2.0	4.8	0.6	2.0	3.0	3.3	254	267	-60.0	-37.0	0.0	0.0	1.1	1.5
Low	1.8	1.9	2.2	1.7	3.4	4.0	1.0	1.2	0.1	0.4	2.3	2.0	200	165	-83.2	-75.0	-0.5	-0.5	0.2	0.7
Standard Deviation	0.4	0.5	0.3	0.7	1.1	1.1	0.4	1.3	0.2	0.4	0.3	0.5	20	35	8.3	12.8	0.2	0.2	0.3	0.3
Comparison Forecasts																				
Riksbank (Feb. '15)	2.7	3.3	2.7	2.8	4.7	5.5			0.1	1.9										
Eur Commission (Jan. '15)	2.3	2.6	2.6	2.6	4.4	4.5														
IMF (Apr. '15)	2.7	2.8							0.2	1.1					-53.8	-26.4				
OECD (Nov. '14)	2.8	3.1	2.6	3.0	4.4	4.4			1.4											

◈ The Riksbank announced an unscheduled rate cut on March 18, slashing the benchmark interest rate to a record low of -0.25%. With inflation at 0.2% (y-o-y) in March, it fears that an appreciating krona, fuelled in part by ECB stimulus measures, may damage efforts to get inflation back towards the 2% target. Furthermore, the bank will quadruple the size of its bond-buying program.

◈ Household consumption rose 0.7% (m-o-m) in February following a 1.9% increase in January. Exports jumped 4.4% (m-o-m) in February and should support the economy towards a robust 2.7% expansion in 2015.



Historical Data

* % change on previous year	2011	2012	2013	2014
Gross Domestic Product*	2.7	-0.3	1.3	2.1
Household Consumption*	1.9	0.9	2.0	2.4
Gross Fixed Investment*	5.8	0.3	-0.3	6.6
Min. & Manufacturing Prodn*	3.0	-3.3	-4.1	-1.9
Consumer Prices*	2.6	0.9	0.0	-0.2
Average Hourly Earnings (Mining & Manufacturing)*	2.8	3.7	2.1	2.3
Current Account, Skr bn	252	244	276	245
General Govt. Bud Bal, Skr bn	-2.9	-34.1	-51.8	-80.7 e
3 mth Interbank Rate, % (end yr)	2.6	1.3	0.9	0.3
10 Yr Govt Bond Yield, % (end yr)	1.6	1.5	2.5	0.9

e = consensus estimate based on latest survey

Nominal GDP - Skr 3,634bn (2013). **Population** - 9.6mn (mid-year, 2013). **Skr/$ Exchange Rate** - 6.514 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***March 9, 2015***

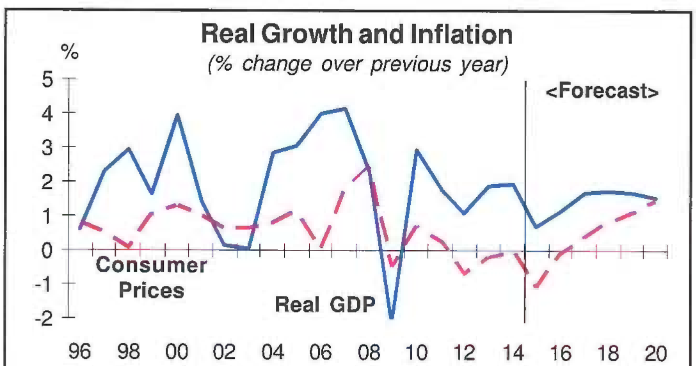
	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4
Gross Domestic Product	2.3	2.6	***2.3***	***2.4***	***2.6***	***2.7***	***2.7***	***2.9***	***2.7***	***2.8***
Consumer Prices	-0.2	-0.2	***0.0***	***0.1***	***0.4***	***0.9***	***1.4***	***1.7***	***1.9***	***2.2***

Percentage Change (year-on-year)

	Average % Change on Previous Calendar Year												Annual Total				Rates on Survey Date			
	Gross Domestic Product		Private Consumption		Gross Fixed Investment		Industrial Production		Consumer Prices		Merchandise Exports (SwFr bn)		Current Account (SwFr bn)		General Govt Budget Balance (SwFr bn)		-0.9% 3 month Euro-Franc Rate (%)		-0.1% 10 Year Govt Bond Yield (%)	
Economic Forecasters	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	End Jul'15	End Apr'16	End Jul'15	End Apr'16
Econ Intelligence Unit	1.2	1.8	2.3	2.3	0.0	0.4	-0.1	2.7	-0.5	-0.1	na	na	54.3	46.4	na	na	na	na	na	na
Swiss Life	1.1	0.7	0.7	0.6	0.5	0.5	0.4	0.5	-1.1	-0.3	na	na	na	na	na	na	na	na	na	na
BAK Basel	1.0	1.8	1.6	1.5	-0.8	1.5	1.0	1.9	-1.0	0.1	219	228	60.5	65.4	0.1	-0.8	-0.8	-0.8	0.0	0.0
Bank Vontobel	1.0	1.5	1.9	2.2	2.1	2.5	na	na	-1.0	0.2	na	na	25.0	30.0	-1.5	0.8	-0.9	-0.9	0.0	0.0
Credit Suisse	0.8	1.2	1.5	1.0	1.2	1.5	na	na	-1.3	0.0	na	na	na	na	na	na	-0.8	-0.8	0.1	0.4
HSBC	0.8	1.1	2.3	2.0	0.2	0.7	-0.2	0.6	-1.1	-0.4	na	na	na	na	na	na	-1.0	-1.0	0.0	0.1
Wellershoff & Partners	0.8	1.0	1.4	1.2	0.5	1.0	na	na	-1.5	-0.5	200	210	na	na	na	na	na	na	na	na
Oxford Economics	0.7	1.7	1.6	1.5	-1.0	1.5	1.0	1.9	-1.0	0.1	202	190	62.4	68.4	0.1	-0.8	-0.8	-0.6	0.0	0.0
Bank Julius Baer	0.7	0.9	1.5	1.8	2.4	3.2	-0.9	1.0	-1.3	-0.1	211	220	40.5	51.9	4.0	5.3	-0.8	-0.8	-0.2	0.3
Pictet & Cie	0.7	1.0	1.3	0.7	1.0	1.5	na	na	-1.1	0.0	na	na	40.0	35.0	-1.5	-2.0	-0.8	-0.7	0.0	0.3
Zürcher Kantonalbank	0.5	1.2	1.6	1.6	0.7	0.8	-0.8	1.8	-0.8	0.4	211	216	41.3	49.5	4.0	5.3	-0.8	-0.6	-0.2	0.0
Goldman Sachs	0.5	1.1	2.1	2.2	0.4	0.7	na	na	-1.4	0.1	na	na	na	na	na	na	na	na	na	na
IHS Economics	0.5	0.7	1.1	0.6	-0.7	1.3	-0.3	1.0	-1.2	-0.4	198	201	31.7	36.2	-3.2	-4.8	-0.9	-0.9	0.1	0.7
UBS	0.5	1.1	1.4	1.5	-0.3	0.6	na	na	-1.0	0.2	na	na	na	na	na	na	-0.7	-0.7	0.0	0.2
KOF Swiss Econ Inst	0.2	1.0	2.1	1.6	-0.1	0.8	na	na	-0.8	0.0	206	210	na	na	-0.9	-1.9	-0.8	-0.8	0.0	0.0
Citigroup	0.0	0.7	2.1	1.4	2.5	2.7	na	na	-1.7	-0.9	na	na	67.5	64.3	na	na	-0.8	-0.8	-0.2	0.1
Consensus (Mean)	0.7	1.2	1.7	1.5	0.5	1.3	0.0	1.4	-1.1	-0.1	207	211	47.0	49.7	0.1	0.1	-0.8	-0.8	0.0	0.2
Last Month's Mean	0.6	1.1	1.6	1.4	0.5	1.0	-0.1	1.2	-1.2	-0.1	199	202	48.7	49.4	0.7	0.6				
3 Months Ago	1.9	2.0	1.8	1.7	2.1	2.9	2.0	2.8	-0.2	0.5	220	232	80.0	86.5	2.8	3.9				
High	1.2	1.8	2.3	2.3	2.5	3.2	1.0	2.7	-0.5	0.4	219	228	67.5	68.4	4.0	5.3	-0.7	-0.6	0.1	0.7
Low	0.0	0.7	0.7	0.6	-1.0	0.4	-0.9	0.5	-1.7	-0.9	198	190	25.0	30.0	-3.2	-4.8	-1.0	-1.0	-0.2	0.0
Standard Deviation	0.3	0.4	0.4	0.6	1.1	0.8	0.7	0.8	0.3	0.3	8	12	14.7	14.2	2.6	3.5	0.1	0.1	0.1	0.2
Comparison Forecasts																				
IMF (Apr. '15)	0.8	1.2							-1.2	-0.4					-2.7	-1.5				
OECD (Nov. '14)	1.5	2.5	1.0	1.9	0.9	2.1			0.3											
SECO (Mar. '15)	0.9	1.8	1.5	1.3					-1.0	0.3										

◈ The outlook remains fragile following the Swiss franc's sudden appreciation. The SNB justified its currency floor abandonment in its recent annual report, stating that the mounting costs of maintaining the floor were outweighing the benefits to the economy. The strengthening franc has adversely impacted consumer prices, which slipped to -0.9% (y-o-y) in March. Fears of a sharp GDP downturn have receded slightly, with the consensus up to +0.7% for 2015.

◈ As exporters struggle to remain competitive, retail turnover dropped by -2.1% (m-o-m) in January signalling much weaker consumer spending.



Historical Data

% change on previous year	2011	2012	2013	2014
Gross Domestic Product*	1.8	1.1	1.9	2.0
Private Consumption*	0.8	2.8	2.2	1.0
Gross Fixed Investment*	4.3	2.4	1.7	1.5
Industrial Production*	2.7	2.3	0.8	1.6
Consumer Prices*	0.2	-0.7	-0.2	0.0
Merch Exports, SwFr bn	198	201	201	208
Current Account, SwFr bn	42.0	62.0	68.0	45.3
General Govt. Bud. Bal. SwFr bn	1.8	0.3	2.9	-1.0
3 mth Euro-Franc Rate, % (end yr)	0.2	-0.1	-0.1	-0.2
10 Yr Govt Bond Yield, % (end yr)	0.7	0.5	1.1	0.4

Nominal GDP - SwFr 603bn (2013). **Population -** 8.1mn (mid-year, 2013). **SwFr/$ Exchange Rate -** 0.927 (average, 2013).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***March 9, 2015***

	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4
Gross Domestic Product	1.9	2.0	***1.5***	***1.1***	***0.4***	***-0.1***	***0.3***	***0.8***	***1.3***	***1.7***
Consumer Prices	0.0	-0.1	***-0.9***	***-1.4***	***-1.4***	***-1.1***	***-0.3***	***0.0***	***0.0***	***0.1***

Percentage Change (year-on-year)

Forecasts for the countries in Western Europe, the Middle East and Africa shown on the next two pages were provided by the following leading economic forecasters, among others:

Bank Leumi · *Bank of America Merrill* · *Barclays Capital*
Citigroup · *Economist Intelligence Unit* · *Euromonitor*
Fitch Ratings · *Forecaster ECOSA* · *Moody's Analytics*
Nomura · *Oxford Economics*

e = consensus estimate based on latest survey

AUSTRIA Population - 8.5mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$415.8bn (2013)	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)	3.1	0.9	0.2	0.3	1.0	1.6
Industrial Production (% change on previous year)	6.1	1.3	0.7	-0.1	1.4	2.4
Consumer Prices (% change on previous year)	3.3	2.4	2.0	1.7	1.1	1.6
Current Account (US Dollar bn)	7.0	6.1	4.1	3.4	5.8	6.1

BELGIUM Population - 11.1mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$505.9bn (2013)	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)	1.6	0.1	0.3	1.0	1.3	1.7
Industrial Production (% change on previous year)	3.9	-2.2	0.7	0.9	1.6	2.7
Consumer Prices (% change on previous year)	3.5	2.8	1.1	0.3	0.3	1.5
Current Account (US Dollar bn)	-5.7	-3.6	-1.2	9.8	2.8	3.1

DENMARK Population - 5.6mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$330.9bn (2013)	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)	1.2	-0.7	-0.5	1.0	1.6	1.8
Manufacturing Production (% change on previous year)	4.7	1.9	2.5	3.0	3.5	2.8
Consumer Prices (% change on previous year)	2.7	2.4	0.8	0.5	0.7	1.5
Current Account (US Dollar bn)	19.6	18.1	24.2	21.1	18.5	16.9

EGYPT Population - 82.1mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$250.4bn (2013)[1]	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)[1]	1.9	2.2	2.1	2.8 *e*	3.8	4.5
Consumer Prices (% change on previous year)	10.1	7.1	9.5	10.1 *e*	10.4	9.4
Current Account (US Dollar bn)	-7.9	-9.5	-3.5	-4.3 *e*	-6.2	-7.7

[1] year(s) ending June 30

FINLAND Population - 5.4mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$257.2bn (2013)	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)	2.6	-1.4	-1.3	-0.1	0.5	1.3
Industrial Production (% change on previous year)	2.3	-1.7	-3.6	-2.9	0.9	2.1
Consumer Prices (% change on previous year)	3.5	2.8	1.5	1.0	0.8	1.3
Current Account (US Dollar bn)	-4.9	-5.0	-4.8	-5.1	-1.7	-2.9

GREECE Population - 11.1mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$241.8bn (2013)	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)	-8.2	-5.9	-3.8	0.8	0.7	2.0
Industrial Production (% change on previous year)	-5.7	-2.0	-3.2	-2.7	0.9	2.1
Consumer Prices (% change on previous year)	3.3	1.5	-0.9	-1.3	-1.3	0.5
Current Account (US Dollar bn)	-28.7	-5.9	1.4	2.1	2.3	2.0

IRELAND Population - 4.6mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$217.8bn (2013)	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)	2.8	-0.3	0.2	4.8	3.2	3.4
Industrial Production (% change on previous year)	0.0	-1.3	-1.3	19.4	5.2	3.4
Consumer Prices (% change on previous year)	2.6	1.7	0.5	0.2	0.1	1.3
Current Account (US Dollar bn)	1.9	3.5	10.1	15.2	12.3	10.4

ISRAEL Population - 7.7mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$290.2bn (2013)	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)	4.2	3.0	3.2	2.9	3.0	3.4
Industrial Production (% change on previous year)	2.1	3.8	0.2	1.2 *e*	2.9	3.3
Consumer Prices (% change on previous year)	3.5	1.7	1.5	0.5	0.2	1.7
Current Account (US Dollar bn)	3.9	2.1	6.9	9.0	10.0	10.6

NIGERIA Popn - 173.6mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$509.1bn (2013)	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)	5.3	4.2	5.5	6.2 *e*	5.0	5.8
Consumer Prices (% change on previous year)	10.8	12.2	8.5	8.0	9.5	9.0
Current Account (US Dollar bn)	12.7	18.9	20.1	6.2 *e*	-15.1	-7.7

PORTUGAL Population - 10.6mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$220.0bn (2013)	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)	-1.8	-3.3	-1.4	0.9	1.6	1.8
Industrial Production (% change on previous year)	-0.9	-6.1	0.4	1.0	1.6	2.6
Consumer Prices (% change on previous year)	3.7	2.8	0.3	-0.3	0.2	0.9
Current Account (US Dollar bn)	-14.8	-4.5	3.2	1.4	1.8	1.8

SAUDI ARABIA Popn - 28.8mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$748.4bn (2013)	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)	10.0	5.4	2.7	3.6	1.2	2.5
Consumer Prices (% change on previous year)	5.8	2.9	3.5	2.7	2.7	3.3
Current Account (US Dollar bn)	159	165	133	96.2 *e*	-7.5	12.4

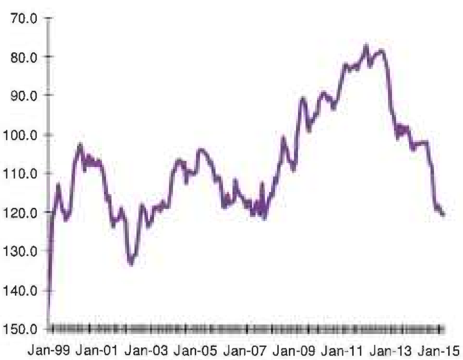
SOUTH AFRICA Popn - 52.8mn (2013, mid-year)	Historical Data				Consensus Forecasts	
Nominal GDP - US$351.4bn (2013)	2011	2012	2013	2014	2015	2016
Gross Domestic Product (% change on previous year)	3.2	2.2	2.2	1.5	2.2	2.8
Manufacturing Production (% change on previous year)	2.8	2.3	1.3	0.0	3.1	4.8
Consumer Prices (% change on previous year)	5.0	5.6	5.7	6.1	4.6	5.7
Current Account (US Dollar bn)	-9.0	-19.7	-21.1	-19.0	-15.7	-15.7

e = consensus estimate based on latest survey

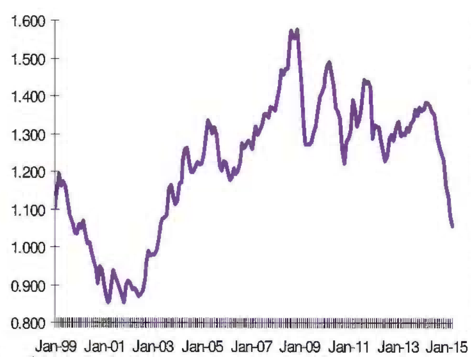
Foreign Exchange Rates

*All US$ rates are amounts of currency per dollar, except the UK pound and the euro which are reciprocals. A positive (+) sign for the % change implies an appreciation of the currency against the US Dollar and vice versa.	Historical Data Rates at end of: 2011	2012	2013	2014	Latest Spot Rate (Apr. 13)	Consensus Forecasts Forecast End Jul. 2015	Percent Change	Forecast End Apr. 2016	Percent Change	Forecast End Apr. 2017	Percent Change
Rates per US Dollar *											
Canadian Dollar	1.021	0.995	1.064	1.160	1.260	1.278	-1.4	1.264	-0.3	1.201	+4.9
Egyptian Pound	5.933	6.056	6.938	7.150	7.602	7.691	-1.1	7.964	-4.5	8.299	-8.4
European Euro	1.294	1.318	1.378	1.214	1.057	1.054	-0.3	1.047	-1.0	1.072	+1.4
Israeli Shekel	3.824	3.736	3.478	3.905	3.990	4.033	-1.1	4.023	-0.8	3.922	+1.8
Japanese Yen	77.72	86.55	105.3	119.9	120.4	122.7	-1.9	125.8	-4.3	123.7	-2.7
Nigerian Naira	158.3	155.3	155.2	183.6	199.1	213.5	-6.8	218.5	-8.9	227.6	-12.6
Saudi Arabian Riyal	3.750	3.750	3.750	3.750	3.751	3.757	-0.2	3.785	-0.9	3.750	0.0
South African Rand	8.143	8.501	10.49	11.58	12.14	12.01	+1.1	11.82	+2.7	11.59	+4.7
United Kingdom Pound	1.546	1.578	1.647	1.561	1.464	1.456	-0.5	1.469	+0.4	1.487	+1.5
Rates per Euro											
Danish Krone	7.435	7.461	7.460	7.446	7.471	7.456	+0.2	7.455	+0.2	7.457	+0.2
Norwegian Krone	7.750	7.343	8.426	9.025	8.554	8.607	-0.6	8.377	+2.1	8.166	+4.8
Swedish Krona	8.913	8.576	8.971	9.484	9.323	9.326	0.0	9.101	+2.4	8.976	+3.9
Swiss Franc	1.218	1.208	1.229	1.201	1.035	1.054	-1.8	1.064	-2.7	1.120	-7.6

Yen per US$

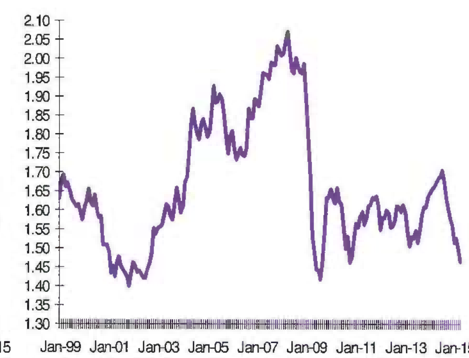


US$ per Euro[1]



[1] *historical rates up to January 1, 1999, are calculated as "synthetic" euro exchange rates based on a weighted average of the eleven original component currencies.*

US$ per UK Pound



APRIL 2015 OIL PRICES

Brent, US$ per barrel		
Range 1990-2015 Spot Rate (Apr. 13)	9.10 - 143.95 57.14	
Brent April Survey	Forecast for End Jul. 2015	End Apr. 2016
Mean Forecast	59.4	67.3
High	78.0	87.0
Low	48.0	57.0
Standard Deviation	5.5	6.9
No. of Forecasts	69	65

Rising Inventories

While European benchmark Brent remained close to US$55-per-barrel over the last two weeks of March and beginning of April, the US measure West Texas Intermediate (WTI) dropped below the US$50-mark. This came on the back of surging US oil inventories. Output increased by 9.4mn barrels in March, according to the US Energy Department, and gasoline inventories also expanded. While this is partly in anticipation of the summer driving season, it also confirms that production is continuing as oil firms try to cover their costs. Saudi Arabia has added to the glut, producing a record 10.3mn barrels per day in March. The world's largest oil producer has continued pumping in order to maintain its market share in the face of rising output from non-OPEC producers like Russia. However, the Saudi oil ministry

continued from page 3

France

* % change over previous year	Historical 2011	2012	2013	2014	Consensus Forecasts 2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	2.1	0.4	0.4	0.4	1.1	1.6	1.7	1.6	1.5	1.4	1.3
Household Consumption*	0.3	-0.5	0.3	0.6	1.3	1.4	1.5	1.4	1.3	1.3	1.4
Business Investment*	4.0	0.3	-0.6	0.7	0.5	2.5	2.9	2.7	2.6	2.4	2.2
Manufacturing Production*	3.9	-3.4	-1.1	0.1	1.3	2.2	1.9	1.6	1.4	1.4	1.4
Consumer Prices*	2.1	2.0	0.9	0.5	0.1	1.1	1.4	1.6	1.7	1.7	1.7
Current Account Balance (Euro bn)	-22.3	-31.9	-30.5	-21.7	-16.8	-13.6	-20.6	-21.9	-21.9	-23.4	-17.2
10 Year Treasury Bond Yield, %[2]	3.2	2.0	2.4	0.8	0.5 [3]	0.8 [4]	1.4	1.9	2.3	2.6	3.1

United Kingdom

* % change over previous year	Historical 2011	2012	2013	2014	Consensus Forecasts 2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	1.6	0.7	1.7	2.8	2.6	2.5	2.3	2.2	2.2	2.2	2.2
Household Consumption*	-0.1	1.5	1.7	2.5	2.8	2.6	2.2	2.1	2.1	2.3	2.2
Gross Fixed Investment*	2.3	0.7	3.4	7.8	4.4	5.4	4.1	3.6	3.1	3.0	3.0
Manufacturing Production*	1.8	-1.3	-0.7	2.8	1.9	2.0	1.6	1.5	1.5	1.5	1.4
Retail Prices (underlying rate)*	5.3	3.2	3.1	2.4	1.5	2.4	2.8	2.9	3.0	3.0	2.9
Consumer Prices*	4.5	2.8	2.5	1.5	0.4	1.6	2.0	2.0	2.1	2.2	2.2
Current Account Balance (£ bn)	-27.0	-61.9	-76.7	-97.9	-81.5	-74.8	-67.3	-65.0	-62.8	-65.2	-72.0
10 Year Treasury Bond Yield, %[2]	2.1	2.0	2.8	1.8	1.9 [3]	2.4 [4]	2.9	3.3	3.4	3.5	3.7

Italy

* % change over previous year	Historical 2011	2012	2013	2014	Consensus Forecasts 2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	0.6	-2.8	-1.7	-0.4	0.6	1.2	1.2	1.2	1.1	1.2	1.1
Household Consumption*	0.0	-3.9	-2.9	0.3	0.6	0.8	1.0	1.0	0.9	1.1	1.2
Gross Fixed Investment*	-1.9	-9.3	-5.8	-3.3	0.0	1.7	2.1	2.4	2.0	2.2	1.7
Industrial Production*	1.2	-6.4	-3.1	-0.8	0.7	2.2	2.3	2.2	2.0	1.9	1.7
Consumer Prices*	2.8	3.1	1.2	0.2	0.1	0.8	1.3	1.4	1.5	1.7	1.8
Current Account Balance (Euro bn)	-50.4	-6.9	15.5	29.6	39.4	38.9	18.6	15.8	16.1	6.3	2.2
10 Year Treasury Bond Yield, %[2]	7.0	4.5	4.1	1.9	1.4 [3]	1.7 [4]	1.9	2.4	2.9	3.3	4.1

Canada

* % change over previous year	Historical 2011	2012	2013	2014	Consensus Forecasts 2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	3.0	1.9	2.0	2.5	2.0	2.1	2.3	2.2	2.1	2.0	1.9
Personal Expenditure*	2.2	1.9	2.5	2.8	2.2	2.0	2.2	2.2	2.2	2.1	2.0
Machinery & Eqpt Investment*	8.1	1.9	-1.7	0.7	-0.4	2.9	3.9	3.6	3.1	2.8	2.6
Industrial Production*	4.1	1.4	1.8	4.1	1.0	1.9	2.7	2.6	2.4	2.3	2.1
Consumer Prices*	2.9	1.5	0.9	1.9	1.0	2.1	2.1	2.0	2.0	2.0	2.0
Current Account Balance (C$ bn)	-47.2	-59.9	-56.3	-43.5	-60.5	-45.5	-34.3	-27.8	-20.8	-19.3	-13.0
10 Year Treasury Bond Yield, %[2]	1.9	1.8	2.8	1.8	1.6 [3]	2.1 [4]	3.2	3.6	3.7	3.9	4.0

Euro zone

* % change over previous year	Historical 2011	2012	2013	2014	Consensus Forecasts 2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	1.7	-0.7	-0.4	0.9	1.5	1.8	1.6	1.6	1.5	1.4	1.4
Private Consumption*	0.2	-1.3	-0.6	1.0	1.7	1.5	1.4	1.4	1.3	1.4	1.3
Gross Fixed Investment*	1.7	-3.5	-2.4	1.0	1.6	2.9	2.4	2.4	2.4	2.0	1.9
Industrial Production*	3.5	-2.4	-0.7	0.8	1.6	2.4	2.2	2.1	1.9	1.6	1.6
Consumer Prices*	2.7	2.5	1.3	0.4	0.1	1.2	1.5	1.7	1.8	1.9	1.9
Current Account Balance (Euro bn)	-6.9	151	214	236	236	232	176	174	131	137	148

[1] Signifies average for period [2] End period [3] End July 2015 [4] End April 2016

The Netherlands

* % change over previous year	Historical 2011	2012	2013	2014	Consensus Forecasts 2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	1.7	-1.6	-0.7	0.9	1.6	1.7	1.5	1.7	1.7	1.7	1.4
Private Consumption*	0.2	-1.4	-1.6	0.1	1.2	1.2	1.0	1.3	1.4	1.5	1.3
Gross Fixed Investment*	5.6	-6.0	-4.0	3.4	3.6	3.0	2.1	2.1	2.3	2.3	1.6
Manufacturing Production*	3.3	-0.8	-1.0	1.1	1.7	1.8	1.3	1.7	1.6	1.7	1.1
Consumer Prices*	2.4	2.4	2.5	1.0	0.5	1.4	1.4	1.5	1.7	1.9	1.9
Current Account Balance (Euro bn)	56.8	70.5	70.4	67.5	69.3	67.7	65.2	66.7	65.4	70.8	72.5
10 Year Treasury Bond Yield, %[2]	2.2	1.5	2.2	0.7	0.4 [3]	0.8 [4]	1.3	1.9	2.6	3.3	3.5

Norway

* % change over previous year	Historical 2011	2012	2013	2014	Consensus Forecasts 2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Dom Prod (Mainland)*	1.9	3.5	2.3	2.3	1.3	1.9	2.2	2.4	2.3	2.3	2.1
Private Consumption*	2.2	3.4	2.1	2.2	1.9	2.0	2.6	2.7	2.7	2.7	2.3
Gross Fixed Investment*	7.4	7.5	6.9	1.2	-3.2	0.4	1.9	2.9	2.6	2.6	1.8
Manufacturing Production*	0.9	2.8	3.7	3.3	0.5	0.5	1.6	1.9	1.4	1.4	1.4
Consumer Prices*	1.3	0.7	2.1	2.0	2.0	2.0	2.1	2.1	2.2	2.1	2.3
Current Account Balance (Nkr bn)	345	369	308	267	221	260	273	291	270	272	232
10 Year Treasury Bond Yield, %[2]	2.4	2.1	3.0	1.6	1.5 [3]	1.8 [4]	2.0	2.6	3.1	3.8	4.3

Spain

* % change over previous year	Historical 2011	2012	2013	2014	Consensus Forecasts 2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	-0.6	-2.1	-1.2	1.4	2.5	2.4	2.1	2.1	2.2	2.2	1.9
Household Consumption*	-2.0	-3.0	-2.3	2.4	2.9	2.5	2.0	2.0	1.9	1.8	1.5
Gross Fixed Investment*	-6.3	-8.1	-3.8	3.4	4.7	4.5	4.2	4.0	3.9	3.8	3.0
Industrial Production*	-2.0	-6.4	-1.7	1.4	1.9	2.5	2.5	2.2	2.5	2.4	2.3
Consumer Prices*	3.2	2.4	1.4	-0.2	-0.5	1.2	1.2	1.4	1.6	1.8	1.8
Current Account Balance (Euro bn)	-34.0	-3.0	15.1	1.2	9.1	7.7	5.7	6.4	9.3	14.7	25.0
10 Year Treasury Bond Yield, %[2]	5.1	5.3	4.1	1.6	1.2 [3]	1.5 [4]	2.3	2.8	3.1	3.4	3.6

Sweden

* % change over previous year	Historical 2011	2012	2013	2014	Consensus Forecasts 2015	2016	2017	2018	2019	2020	2021-2025
Gross Domestic Product*	2.7	-0.3	1.3	2.1	2.7	2.9	2.5	2.2	2.2	2.0	1.9
Household Consumption*	1.9	0.9	2.0	2.4	2.7	2.7	2.4	2.2	2.1	2.0	1.9
Gross Fixed Investment*	5.8	0.3	-0.3	6.6	5.1	5.2	3.9	3.3	3.1	2.7	2.5
Mining & Manufacturing Production*	3.0	-3.3	-4.1	-1.9	1.4	3.4	3.6	3.4	3.1	1.9	1.9
Consumer Prices*	2.6	0.9	0.0	-0.2	0.3	1.4	2.5	2.5	2.3	2.2	2.2
Current Account (Skr bn)	252	244	276	245	230	217	220	219	218	201	207
10 Year Treasury Bond Yield, %[2]	1.6	1.5	2.5	0.9	0.6 [3]	1.1 [4]	2.4	3.0	3.6	4.2	4.3

Switzerland

* % change over previous year	Historical 2011	2012	2013	2014	Consensus Forecasts 2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	1.8	1.1	1.9	2.0	0.7	1.2	1.7	1.7	1.7	1.6	1.5
Private Consumption*	0.8	2.8	2.2	1.0	1.7	1.5	1.7	1.7	1.7	1.5	1.5
Gross Fixed Investment*	4.3	2.4	1.7	1.5	0.5	1.3	2.7	2.9	2.1	2.1	2.0
Industrial Production*	2.7	2.3	0.8	1.6	0.0	1.4	2.6	2.4	2.2	1.9	1.7
Consumer Prices*	0.2	-0.7	-0.2	0.0	-1.1	-0.1	0.4	0.8	1.1	1.5	1.5
Current Account Balance (SwFr bn)	42.0	62.0	68.0	45.3	47.0	49.7	57.6	62.8	66.6	72.1	75.8
10 Year Treasury Bond Yield, %[2]	0.7	0.5	1.1	0.4	0.0 [3]	0.2 [4]	1.0	1.5	2.1	2.6	2.6

[1]Signifies average for period [2]End period [3]End July 2015 [4]End April 2016

- GDP - Gross Domestic Product IMF - International Monetary Fund
  na - not available Emu - European economic and monetary union
  OECD - Organisation for Economic Co-operation and Development ECB - European Central Bank
  BoE - Bank of England PMI - Purchasing Managers Index
  y-o-y - year-on-year q-o-q - quarter-on-quarter m-o-m - month-on-month

- Measures of GDP, Consumption, Business Investment and Industrial Production are expressed in real (i.e. inflation-adjusted) terms. These variables, and certain others as indicated, are expressed as percentage changes over the previous year.

- All individual country forecasters on pages 4-24 are listed in descending order of their 2015 real GDP estimates. Consensus forecasts are mean arithmetic averages of the listed individual estimates.

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CONSENSUS FORECASTS: WORLD ECONOMIC ACTIVITY

April Survey	Real GDP % increase			Consumer Prices % increase			Current Account Balance, US$bn		
	2014	2015	2016	2014	2015	2016	2014	2015	2016
Belgium	1.0	**1.3**	**1.7**	0.3	**0.3**	**1.5**	9.8	**2.8**	**3.1**
Canada	2.5	**2.0**	**2.1**	1.9	**1.0**	**2.1**	-39.4	**-47.9**	**-36.4**
France	0.4	**1.1**	**1.6**	0.5	**0.1**	**1.1**	-28.8	**-18.1**	**-14.4**
Germany	1.6	**1.9**	**2.0**	0.9	**0.4**	**1.6**	292	**246**	**241**
Italy	-0.4	**0.6**	**1.2**	0.2	**0.1**	**0.8**	39.3	**42.3**	**40.9**
Japan	-0.1	**1.0**	**1.7**	2.7	**0.7**	**1.0**	24.6	**114.0**	**108.2**
Netherlands	0.9	**1.6**	**1.7**	1.0	**0.5**	**1.4**	89.7	**74.4**	**71.3**
Norway	2.3	**1.3**	**1.9**	2.0	**2.0**	**2.0**	42.3	**27.5**	**32.8**
Spain	1.4	**2.5**	**2.4**	-0.2	**-0.5**	**1.2**	1.6	**9.7**	**8.1**
Sweden	2.1	**2.7**	**2.9**	-0.2	**0.3**	**1.4**	35.7	**26.5**	**25.1**
Switzerland	2.0	**0.7**	**1.2**	0.0	**-1.1**	**-0.1**	49.5	**47.8**	**48.6**
United Kingdom	2.8	**2.6**	**2.5**	1.5	**0.4**	**1.6**	-161.4	**-120.2**	**-110.1**
United States	2.4	**2.9**	**2.8**	1.6	**0.1**	**2.2**	-411	**-404**	**-459**
North America[1]	2.4	**2.8**	**2.8**	1.6	**0.2**	**2.2**	-450.4	**-452.3**	**-495.8**
Western Europe[2]	1.3	**1.7**	**1.9**	0.7	**0.2**	**1.3**	407.8	**377.5**	**381.4**
European Union[2]	1.3	**1.8**	**2.0**	0.6	**0.2**	**1.3**	314.7	**300.0**	**292.9**
Euro zone[2]	0.9	**1.5**	**1.8**	0.4	**0.1**	**1.2**	313.0	**253.1**	**244.1**
Asia Pacific[3]	4.6	**4.7**	**4.9**	2.7	**1.7**	**2.3**	402.8	**611.5**	**578.6**
Eastern Europe[4]	1.6	**-0.4**	**2.1**	7.4	**8.1**	**5.7**	4.4	**-8.2**	**-7.8**
Latin America[5]	1.0	**0.8**	**2.3**	11.4	**13.3**	**10.5**	-160.7	**-171.8**	**-159.7**
Other Countries[6]	3.7	**2.8**	**3.7**	5.1	**5.2**	**5.5**	88.1	**-34.5**	**-8.1**
Total[7]	2.7	**2.7**	**3.2**	3.0	**2.5**	**3.0**			

*Regional totals and the grand total for GDP growth and inflation, are weighted averages calculated using **2013 GDP weights, converted at average 2013 exchange rates.** Current account forecasts given in national currencies on pages 7-24 have been converted using consensus exchange rate forecasts for the purposes of comparison. [1] USA and Canada. [2] The Euro zone aggregate is taken from our panel's latest forecasts (pages 18-19). The Euro zone current account data and forecasts are based on extra-euro zone data, i.e., an aggregate of the Euro zone member states' transactions with nonresidents of the Euro zone. The European Union data includes the Euro zone countries listed on page 18 plus Denmark, Sweden and the United Kingdom, as well as the Czech Republic, Hungary, Lithuania and Poland, plus Romania and Bulgaria which entered in January 2007, plus Croatia which entered in July 2013 (data taken from Eastern Europe Consensus Forecasts). Western Europe comprises the six Euro zone countries listed above, plus Austria, Denmark, Finland, Greece, Ireland, Norway, Portugal, Sweden, Switzerland and the United Kingdom. [3] Survey results for Japan plus fifteen other countries taken from **Asia Pacific Consensus Forecasts**. [4] Twenty-seven countries, including eleven European Union countries taken from the latest issue of **Eastern Europe Consensus Forecasts.** [5] Eighteen countries taken from the latest issue of **Latin American Consensus Forecasts** (inflation figures are on a December/December basis). [6] Egypt, Israel, Nigeria, Saudi Arabia and South Africa. [7] The **Eastern Europe** and **Latin American** components of the **World Total** are taken from prior months surveys.*

Blue Chip Economic Indicators®

Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead

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Little Change This Month In Outlook For 2016 Real GDP Growth

Domestic Commentary The consensus forecast of annual real GDP growth this year rose a tad this month, while the forecast of annual growth next year slipped by an equal amount, but it was much ado about nothing as forecasts of growth measured on a fourth quarter-over-fourth quarter basis (q4/q4) remained unchanged. The changes in the forecasts of annual real GDP growth resulted from an upward revision in the second estimate of growth last quarter by the Bureau of Economic Analysis (BEA) that was larger than a decline this month in the consensus forecast of growth in the current quarter, coupled with a small decline in consensus estimate of growth in the initial quarter of next year along with unchanged estimates of growth over the remaining three quarters. The consensus now forecasts real GDP will grow 2.5% on an annual basis in both 2015 and 2016, but 2.2% and 2.6%, respectively, on a q4/q4 basis. That compares with annual growth of 2.4% in 2014 and a q4/q4 increase of 2.5%.

According to our December 3rd-4th survey, consumer spending is expected to remain the primary catalyst of economic growth in 2016, supported by further improvement in labor market conditions, another healthy increase in disposable personal income (DPI), and looser lending standards. Growth in real nonresidential fixed investment is predicted to improve modestly over that seen in 2015, aided in large part by diminishing drag from the oil and gas sector. Real residential investment, too, is predicted to expand again next year, but by less than forecast over the past three months. Total government spending and investment in 2016 will likely register its first annual increase since 2010, according to most analysts. On the other hand, the strength of the U.S. dollar and relatively weaker economic growth abroad, is predicted to widen the trade deficit for a third, consecutive year in 2016, albeit by less than that witnessed this year. Weakness this year in total industrial production should begin to gradually give way to better growth in early 2016 as the recent drawdown in private inventories runs its course and the plunge in oil and gas exploration plays out. However, if predictions of a warm winter pan out, we will likely continue to see downward pressure on utility output in the short term.

The consensus forecasts that y/y measures of headline inflation are on the verge of bottoming, and will rapidly lift toward the 2.0% level by next summer. The rebound is largely premised on base effects. Energy prices plunged from the summer of 2014 through very early this year. As the effects of that decline begin to roll out of the data in the next couple of months, the y/y change in headline inflation measures will jump. Core inflation appears to have already bottomed, thus its acceleration in 2016 is expected to be much more limited.

The anticipated acceleration of inflation, combined with labor market conditions that now appear to meet the Federal Reserve's objectives, is widely expected to prompt the Federal Open Market Committee (FOMC) into hiking interest rates by 25 basis points at its December 15th-16th meeting, marking the first increase in nine years. Further, gradual increases by the FOMC of 75 to 100 basis points are foreseen by the consensus in 2016, according to a special question asked of the panelists this month. The consensus anticipates that 10-year Treasury notes yields will be approaching the 3.0% level by the end of next year versus the current level of about 2.25%

Real GDP grew an upwardly revised 2.1% (q/q,saar) in Q3, according to BEA's second estimate, 0.6 of a percentage point faster than its initial guess and much closer to what the consensus had expected ahead of the original estimate from the government. The upward revision in GDP was accounted for higher inventories as the change in real inventories went to $90.2 billion from $56.8 billion. As a result, inventories now are believed to have subtracted only 0.6 of a percentage point from real GDP's growth rate in Q3 rather than the 1.4 points initially estimated. Growth in real personal consumption expenditures (PCE) was revised down from 3.2% (q/q,saar) to a still healthy 3.0%, but growth in business fixed investment was revised higher to 3.4% (q/q,saar), 1.3 percentage points faster than first estimated. The rate of growth in real residential investment was revised up 1.2 percentage points to 7.3%. Real net exports last quarter are now estimated to have subtracted a bit more from GDP than previously thought. Growth during Q3 in real domestic final sales (GDP minus inventories and net exports) were revised to 2.8% versus the first estimate of 2.9%.

The consensus looks for real GDP to grow 2.2% (q/q,saar) in the current quarter, 0.5 of a percentage point slower than estimated a month ago. Due to the upward revision by BEA in Q3 inventories, the consensus now believes they will subtract more than previously expected from GDP in Q4. Real net exports also are now predicted by the consensus to subtract more from GDP this quarter than estimated a month ago. The consensus forecasts that real PCE growth will slow to a still relatively healthy rate of 2.7% (q/q,saar) in Q4. However, Real PCE started the quarter with a weak gain of just 0.1% and November may not have been much stronger, suggesting downside risk to the current consensus estimate despite the recent strength in real DPI. Real nonresidential and residential investment growth during the current quarter will likely be on par with that seen in Q3, but government spending and investment may weaken given the recent trend of solid growth in Q2 and Q3 followed by softness in Q1 and Q4.

For all of 2015, the consensus predicts real PCE will register an annual increase of 3.1%, 0.1 of a percentage point less than last month. That still would be the largest increase since 2005. Real DPI is predicted to grow 3.5%, 0.3 of a percentage point more than forecast a month ago. Real nonresidential fixed investment still is forecast to increase 3.3% this year. Housing starts now are forecast to total 1.11 million units this year, down 10,000 units from a month ago, but an increase of 11.0% over 2014. The consensus forecast for auto and light truck sales increased for a fifth consecutive month to 17.4 million units. The real net export deficit is expected to total $543.4 billion this year, marking a widening over last year of about $100 billion. The GDP price index still is forecast to increase 1.0% y/y and 1.2% q4/q4, both estimates down 0.1 of a percentage point over the past month. Also unchanged, the CPI is forecast to increase 0.2% y/y, but only 0.5% on a q4/q4 basis.

In 2016, the consensus now sees real GDP growth of 2.5% (q/q,saar) in Q1, 0.1 of a percentage point slower than last month. However, forecasts of growth over the next three quarters went unchanged this month at 2.7% (q/q,saar) in Q2 and 2.6% in both Q3 and Q4. The consensus forecast of the annual change in nominal (current dollar) GDP in 2016 fell 0.1 of a percentage point for the fifth consecutive month to 4.3%. However, that still is 0.8 of a percentage point more than the predicted increase in 2015. Real PCE is forecast to increase 2.8% y/y in 2016, 0.1 of a point less than last month, but the forecast for real DPI growth jumped 0.2 of a point to 2.9%. Real nonresidential fixed investment is forecast to increase 4.3%, 0.1 of a percentage point more than last month's estimate. The consensus predicts that housing starts will total 1.25 million units next year, down from last month's forecast of 1.28 million. On the other hand, the forecast of total car and light trucks sales rose to 17.6 million units, 200,000 more than last month. The unemployment rate still is expected to average 4.8% next year versus an expected average of 5.3% in 2015. The GDP price index is forecast to increase 1.7% y/y, but 1.9% q4/q4. The q4/q4 estimate slipped to 1.9%. The y/y forecast for the CPI remained at 1.8%, but the forecast of its q4/q4 change slipped 0.1 of a point to 2.1%.

International Commentary For the most part, America's major trading partners are expected to experience modestly stronger economic growth in 2016 than in 2015. The major exception is China. Real GDP in Russia and Brazil is predicted to contract for a second consecutive year in 2016, but by less than in 2015 *(see pages 6-7)*.

Special Questions The consensus predicts average monthly nonfarm payroll increases of about 189,000 next year. The PCE price index and core PCE price index will both register December-over-December increases of 1.9% next year *(see page 14)*.

GREEN indicates the Blue Chip consensus forecast of real GDP growth over the next four quarters is 3.0 percent or more.
YELLOW cautions that the consensus forecast of real GDP growth over the next four quarters is between 1.5 percent and 2.9 percent.
RED warns that the consensus forecast of real GDP growth of real GDP growth over the next four quarters is less than 1.5 percent.

2015 Real GDP Forecast Inches Back Up To 2.5%

DECEMBER 2015 Forecast For 2015 SOURCE:	Percent Change 2015 From 2014 (Full Year-Over-Prior Year)									Average For 2015			Total Units-2015		2015
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Real GDP (Chained) (2009$)	GDP Price Index	Nominal GDP (Cur.$)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income (2009$)	Personal Cons. Exp. (2009$)	Non-Res. Fix. Inv. (2009$)	Corp. Profits (Cur.$)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto&Light Truck Sales (Mil.)	Net Exports (2009$)
Ford Motor Company*	2.6 H	1.0 L	3.6	0.2	1.6	3.4	3.2 H	4.8 H	na	na	2.2	5.3 H	1.12	na	-547.4
Societe Generale	2.6 H	1.0 L	3.6	0.1 L	1.7	4.0 H	3.1	3.1	1.4	0.1	2.1 L	5.2 L	1.12	17.4	-543.3
ACT Research	2.5	1.1	3.6	0.1 L	1.4	3.5	3.1	3.3	na	0.1	2.1 L	5.3 H	1.11	17.4	-547.0
Action Economics	2.5	1.0 L	3.5	0.2	1.4	3.6	3.1	3.1	-0.9	0.1	2.1 L	5.3 H	1.15 H	17.4	-537.1
Amherst Pierpont Securities	2.5	1.0 L	3.5	0.1 L	1.4	3.6	3.1	3.3	-0.7	0.1	2.2	5.3 H	1.10	17.5 H	-544.0
Bank of America Merrill Lynch	2.5	1.0 L	3.5	0.1 L	1.4	3.6	3.1	3.1	-1.0	0.2 H	2.3 H	5.3 H	1.11	17.4	-542.0
Barclays*	2.5	1.0 L	3.5	0.1 L	na	na	3.1	3.3	na	na	2.2	5.3 H	1.10	na	-545.2
BMO Capital Markets*	2.5	1.0 L	3.5	0.1 L	1.5	3.6	3.1	3.1	-0.7	0.1	2.2	5.3 H	1.10	17.4	-541.5
BNP Paribas North America	2.5	na	na	0.1 L	1.6	3.2	3.1	3.1	na	na	2.1 L	5.3 H	1.10	na	-550.0
Conference Board*	2.5	1.0 L	3.5	0.2	1.6	3.6	3.1	3.2	-0.9	0.0 L	2.1 L	5.3 H	1.10	17.4	-543.0
Credit Suisse	2.5	1.0 L	3.6	0.1 L	1.6	na	3.1	3.2	-0.4	na	2.2	5.3 H	1.08 L	na	-542.5
Daiwa Capital Markets America	2.5	1.0 L	3.5	0.1 L	1.4	3.6	3.1	3.3	-0.8	0.1	2.2	5.3 H	1.11	17.4	-544.0
Economist Intelligence Unit	2.5	1.1	3.6	0.2	1.5	3.1	2.9 L	3.5	na	0.1	2.2	5.3 H	1.15 H	17.4	-545.0
Fannie Mae	2.5	1.0 L	3.5	0.1	1.7	3.6	3.1	3.1	-1.1	0.1	2.1 L	5.3 H	1.11	17.4	-540.4
General Motors	2.5	1.0 L	3.5	0.1 L	1.4	3.6	3.2 H	3.0 L	-1.9	0.1	2.1 L	5.3 H	1.12	na	-536.6
Georgia State University*	2.5	1.0 L	3.6	0.1 L	1.5	3.7	3.2 H	3.3	0.8	0.0 L	2.2	5.3 H	1.13	17.4	-545.1
Goldman Sachs & Co.**	2.5	1.0 L	3.5	0.2	1.7	3.6	3.1	3.2	na	0.0 L	2.2	5.3 H	1.12	na	-545.1
High Frequency Economics	2.5	1.0 L	3.6	0.2	1.4	3.6	3.1	3.3	-1.0	0.2 H	2.2	5.3 H	1.10	17.4	-546.5
IHS Global Insight	2.5	1.0 L	3.5	0.1 L	1.4	3.6	3.1	3.3	-1.1	0.1	2.1 L	5.3 H	1.10	17.4	-543.8
Inforum - Univ. of Maryland	2.5	1.0 L	3.6	0.2	1.6	3.5	3.1	3.3	0.0	0.1	2.2	5.3 H	1.12	17.2	-542.5
J P MorganChase	2.5	1.0 L	3.5	0.1 L	2.0	3.6	3.1	3.5	-0.6	na	2.1	5.3 H	1.11	17.3	-538.4
Macroeconomic Advisers, LLC**	2.5	1.0 L	3.5	0.1 L	1.5	3.6	3.1	3.1	-1.4	0.1	2.1	5.3 H	1.11	17.4	-541.5
MacroFin Analytics	2.5	1.0 L	3.5	0.2	1.7	3.2	3.1	3.2	-1.1	0.0 L	2.1	5.3 H	1.12	17.4	-537.1
Mesirow Financial	2.5	1.0 L	3.5	0.1 L	1.5	3.6	3.1	3.1	-1.4	0.1	2.1 L	5.3 H	1.11	17.4	-539.0
Moody's Analytics	2.5	1.0 L	3.4 L	0.2	1.5	3.4	3.2 H	3.2	0.7	0.0 L	2.2	5.3 H	1.14	17.3	-542.1
Moody's Capital Markets*	2.5	1.0 L	3.5	0.1 L	1.5	3.5	3.1	3.2	0.3	0.1	2.1 L	5.3 H	1.10	17.4	-544.2
Morgan Stanley*	2.5	1.0 L	3.5	0.1 L	2.0	3.6	3.1	3.5	-0.6	na	2.1 L	5.3 H	1.11	17.3	-538.4
MUFG Union Bank	2.5	1.0 L	3.5	0.2	1.5	na	3.0	3.5	0.0	0.1	2.1 L	5.3 H	1.11	17.4	-540.0
Naroff Economic Advisors*	2.5	1.2 H	3.7 H	0.1 L	1.9	3.4	3.1	3.7	5.0	0.1	2.3 H	5.3 H	1.11	17.3	-540.0
National Assn. of Home Builders	2.5	1.0 L	3.6	0.2	1.5	3.5	3.2 H	3.3	na	0.1	2.2	5.3 H	1.11	17.3	-544.0
Nomura Securities	2.5	1.0 L	3.5	0.1 L	1.4	3.6	3.1	3.3	na	0.0 L	2.1 L	5.3 H	1.10	17.4	-542.7
Northern Trust Company*	2.5	1.0 L	3.5	0.2	1.6	3.1	3.1	3.2	na	0.0 L	2.2	5.3 H	1.10	17.4	-546.5
PNC Financial Services Group	2.5	1.0	3.5	0.2	1.5	3.2	3.2 H	3.2	na	0.1	2.2	5.3 H	1.12	17.4	-538.3
Point72 Asset Management	2.5	1.1	3.6	0.2	1.5	3.6	3.1	3.1	-0.8	0.0 L	2.1 L	5.2 L	1.11	17.3	-540.7
RBC Capital Markets	2.5	1.1	3.6	0.1 L	na	na	3.1	3.2	na	0.0 L	2.2	5.3 H	1.12	17.4	-541.0
RBS Securities	2.5	1.0 L	3.5	0.2	1.3 L	3.3	3.1	3.3	0.0	0.0 L	2.1 L	5.3 H	1.10	17.4	-542.0
RDQ Economics	2.5	1.1	3.6	0.2	1.4	3.6	3.1	3.2	0.3	0.1	2.2	5.3 H	1.10	17.5 H	-537.3
Regions Financial Corporation	2.5	1.1	3.6	0.1 L	1.5	3.6	3.2 H	3.1	-1.5	0.1	2.1 L	5.3 H	1.10	17.4	-542.7
SOM Economics, Inc.	2.5	1.0 L	3.5	0.2	1.5	3.6	3.2 H	3.1	-1.0	0.1	2.1 L	5.3 H	1.12	17.4	-541.0
Standard & Poors Corp.*	2.5	1.0 L	3.5	0.1 L	1.5	3.1	3.2 H	3.1	-0.7	0.0 L	2.2	5.3 H	1.13	17.4	-539.1
Swiss Re	2.5	1.0 L	3.5	0.1 L	1.7	3.6	3.1	3.4	-0.5	0.1	2.1 L	5.3 H	1.12	17.2	-548.0
Turning Points (Micrometrics)	2.5	1.0 L	3.5	0.2	1.6	3.0 L	3.2 H	4.0 H	0.0	0.1	2.2	5.3 H	1.12	17.5 H	-545.8
U.S. Chamber of Commerce	2.5	1.0 L	3.6	0.2	1.5	3.6	3.1	3.0 L	1.0	0.1	2.2	5.3 H	1.10	na	-543.6
UBS	2.5	1.0 L	3.6	0.2	1.7	3.6	3.1	3.3	na	0.1	2.2	5.3 H	1.14	na	-542.7
UCLA Business Forecasting Proj.*	2.5	1.1	3.6	0.1 L	1.3 L	3.3	3.2 H	3.3	0.4	0.1	2.2	5.3 H	1.13	17.4	-544.0
Wells Capital Management	2.5	1.0 L	3.6	0.1 L	1.7	3.6	3.1	3.3	-0.8	0.1	2.2	5.3 H	1.11	17.4	-546.0
Oxford Economics	2.5	1.1	3.5	0.1 L	1.5	3.5	3.1	3.1	-2.0	0.1	2.1 L	5.3 H	1.11	17.5 H	-537.9
AIG	2.4 L	1.1	3.5	0.2	1.5	3.1	3.0	3.0 L	-2.3 L	0.0 L	2.1 L	5.3 H	1.11	17.1 L	-535.0 H
Comerica*	2.4 L	1.0 L	3.5	0.2	1.6	3.6	3.2 H	3.2	na	0.0 L	2.2	5.3 H	1.13	17.4	-541.9
Eaton Corporation	2.4 L	1.2 H	3.6	0.3 H	2.3 H	3.1	3.2	3.2	6.0 H	0.1	2.2	5.3 H	1.13	17.4	-600.0 L
Econoclast	2.4 L	1.1	3.5	0.2	1.5	3.4	3.0	3.2	0.2	0.1	2.2	5.3 H	1.10	17.4	-540.0
FedEx Corporation	2.4 L	1.0 L	3.5	0.2	1.5	3.6	3.1	3.0 L	-0.4	0.1	2.1 L	5.3 H	1.12	17.3	-539.7
Wells Fargo	2.4 L	1.0 L	3.4 L	0.2	1.5	3.5	3.1	3.3	1.7	0.0 L	2.1 L	5.3 H	1.12	17.4	-547.3
2015 Consensus: December Avg.	**2.5**	**1.0**	**3.5**	**0.2**	**1.6**	**3.5**	**3.1**	**3.3**	**-0.2**	**0.1**	**2.2**	**5.3**	**1.11**	**17.4**	**-543.4**
Top 10 Avg.	2.5	1.1	3.6	0.2	1.8	3.7	3.2	3.7	1.8	0.1	2.2	5.3	1.14	17.4	-537.5
Bottom 10 Avg.	2.4	1.0	3.5	0.1	1.4	3.1	3.1	3.1	-1.5	0.0	2.1	5.3	1.10	17.3	-552.5
November Avg.	2.4	1.0	3.5	0.2	1.5	3.2	3.2	3.3	0.8	0.1	2.2	5.3	1.13	17.3	-540.7
Historical data 2011	1.6	2.1	3.7	3.2	3.0	2.5	2.3	7.7	4.0	0.1	2.8	9.0	0.61	12.7	-459.4
2012	2.2	1.8	4.1	2.1	2.8	3.2	1.5	9.0	10.0	0.1	1.8	8.1	0.78	14.4	-447.1
2013	1.5	1.6	3.1	1.5	1.9	-1.4	1.7	3.0	2.0	0.1	2.4	7.4	0.92	15.5	-417.5
2014	2.4	1.6	4.1	1.6	3.7	2.7	2.7	6.2	1.7	0.0	2.5	6.2	1.00	16.4	-442.5
Number Of Forecasts Changed From A Month Ago:															
Down	0	7	4	7	9	1	35	15	33	4	5	0	33	1	36
Same	29	38	25	39	21	9	15	19	2	27	36	52	16	19	7
Up	24	7	23	7	21	39	3	19	5	16	12	1	4	25	10
December Median	2.5	1.0	3.5	0.1	1.5	3.6	3.1	3.2	-0.7	0.1	2.2	5.3	1.11	17.4	-542.5
December Diffusion Index	73 %	50 %	68 %	50 %	62 %	89 %	20 %	54 %	15 %	63 %	57 %	51 %	23 %	77 %	25 %

***Former winner of annual Lawrence R. Klein Award for Blue Chip Forecast Accuracy. **Denotes two-time winner. ***Denotes three-time winner.**

2016 Real GDP Forecast Slips To 2.5%

DECEMBER 2015 Forecast For 2016 SOURCE:	---------- Percent Change 2016 From 2015 (Full Year-Over-Prior Year) -------------------									--- Average For 2016 ----			-- Total Units-2016 ----		--2016---
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Real GDP (Chained) (2009$)	GDP Price Index	Nominal GDP (Cur.$)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income (2009$)	Personal Cons. Exp. (2009$)	Non-Res. Fix. Inv. (2009$)	Corp. Profits (Cur.$)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto&Light Truck Sales (Mil.)	Net Exports (2009$)
Naroff Economic Advisors*	3.2 H	2.7 H	5.9 H	2.0	3.1 H	3.0	3.0	5.5	6.8	1.1	3.2	4.7	1.36	17.6	-581.0
UCLA Business Forecasting Proj.*	3.2 H	2.3	5.6	2.1	1.9	3.3	3.2	6.4	10.2	0.9	3.1	4.7	1.44	18.0	-655.4 L
Moody's Analytics	3.0	1.6	4.4	2.0	1.6	3.5	3.5 H	5.0	9.1	0.4 L	3.0	4.9	1.47 H	17.2	-595.6
Societe Generale	2.9	1.9	4.8	1.8	2.5	5.2 H	2.8	3.5	3.9	0.9	2.6	4.5	1.26	18.0	-584.6
National Assn. of Home Builders	2.8	1.9	4.8	1.6	2.0	2.5	3.1	4.3	na	0.9	2.9	5.0	1.26	17.3	-586.0
RBC Capital Markets	2.8	2.2	5.0	1.9	na	na	2.7	3.8	na	0.6	2.8	4.4 L	1.20	17.6	-560.0
SOM Economics, Inc.	2.8	1.2 L	4.0	1.3	2.2	2.9	2.8	3.3	4.0	0.7	2.6	4.6	1.23	18.4 H	-552.0
UBS	2.8	2.0	4.9	1.6	2.0	3.3	3.0	5.1	na	1.1	2.4 L	4.8	1.31	na	-590.8
Credit Suisse	2.7	1.6	4.3	1.4	2.0	na	3.2	3.7	3.5	na	2.8	4.6	1.15	na	-599.2
Ford Motor Company*	2.7	1.7	4.5	1.8	2.3	2.0 L	3.2	6.9 H	na	na	2.9	5.2 H	1.31	na	-635.1
Georgia State University*	2.7	1.9	4.6	1.6	1.9	3.3	2.9	5.3	10.0	0.5	2.7	5.1	1.21	17.0	-599.8
IHS Global Insight	2.7	1.8	4.6	1.4	1.0 L	3.1	3.1	5.3	5.8	0.8	2.7	4.9	1.23	17.8	-618.3
MUFG Union Bank	2.7	1.7	4.4	2.6 H	2.0	na	2.9	6.6	7.0	1.0	3.0	4.6	1.35	18.0	-580.0
RDQ Economics	2.7	1.9	4.6	1.9	1.6	3.0	2.7	4.5	4.5	1.1	3.2	4.5	1.15	18.0	-558.6
Standard & Poors Corp.*	2.7	1.9	4.6	1.7	1.9	2.5	3.1	4.7	0.4	0.7	2.7	4.8	1.33	18.0	-612.0
Swiss Re	2.7	1.3	4.1	1.7	2.6	3.2	2.9	6.4	4.6	0.8	2.6	4.7	1.28	16.7 L	-633.8
BMO Capital Markets*	2.6	1.7	4.4	1.8	1.8	3.1	2.8	3.9	3.9	0.7	2.6	4.7	1.30	17.8	-581.5
Comerica*	2.6	1.7	4.3	2.1	3.0	4.6	2.7	4.1	na	0.6	2.7	4.6	1.27	16.9	-582.0
Economist Intelligence Unit	2.6	2.0	4.6	1.6	2.8	2.6	2.7	4.8	na	0.6	2.8	4.9	1.27	17.4	-600.0
FedEx Corporation	2.6	1.7	4.3	1.9	1.9	2.9	2.8	3.4	4.1	0.8	2.8	4.9	1.30	17.7	-577.8
Inforum - Univ. of Maryland	2.6	1.7	4.3	1.7	2.3	2.8	2.8	4.4	4.9	1.0	2.9	4.9	1.28	17.4	-583.0
U.S. Chamber of Commerce	2.6	1.7	4.4	1.9	1.7	2.9	3.0	3.4	4.0	0.7	2.8	4.9	1.24	na	-577.1
Wells Capital Management	2.6	1.8	4.4	1.6	3.1 H	3.0	2.7	5.9	2.8	1.0	2.6	4.8	1.14	17.6	-602.0
Oxford Economics	2.6	1.9	4.5	1.7	1.5	2.7	2.9	3.7	-0.8	0.4 L	2.5	4.8	1.33	18.1	-561.0
Action Economics	2.5	1.6	4.1	1.8	1.2	3.0	2.9	3.1	4.1	0.6	2.6	4.7	1.22	18.3	-548.9
Amherst Pierpont Securities	2.5	1.9	4.5	2.1	1.1	2.9	2.7	4.4	4.5	1.2	3.4 H	4.7	1.26	17.5	-568.0
Barclays*	2.5	1.6	4.1	1.3	na	na	2.9	5.2	na	na	2.5	4.5	1.24	na	-602.4
General Motors	2.5	1.6	4.1	1.6	1.4	2.9	2.8	2.5 L	-0.9 L	0.6	2.9	4.8	1.30	na	-582.0
High Frequency Economics	2.5	2.0	4.6	2.2	1.2	2.8	2.7	4.4	3.5	1.4 H	3.2	4.5	1.25	18.2	-582.0
Macroeconomic Advisers, LLC**	2.5	1.6	4.1	1.6	2.1	2.9	3.1	2.8	0.1	0.6	2.9	4.8	1.30	17.5	-594.5
MacroFin Analytics	2.5	1.5	4.0	1.6	3.1	2.4	2.8	4.1	3.9	0.7	2.7	4.9	1.10 L	17.1	-515.0 H
Mesirow Financial	2.5	1.6	4.1	1.6	1.4	2.9	3.1	2.6	0.0	0.6	2.9	4.7	1.29	17.3	-593.6
Northern Trust Company*	2.5	1.5	4.0	1.6	2.4	2.8	2.8	4.1	na	0.4 L	2.6	4.9	1.25	17.1	-588.6
PNC Financial Services Group	2.5	1.5	3.9	1.9	1.7	2.6	2.6	3.3	na	0.8	2.6	4.7	1.22	18.0	-553.2
Turning Points (Micrometrics)	2.5	1.5	4.0	2.0	1.8	2.6	2.9	4.6	15.1 H	0.6	2.6	4.8	1.25	18.3	-615.1
Conference Board*	2.4	1.8	4.2	1.8	2.2	2.9	2.6	3.9	0.0	0.6	2.5	4.7	1.28	17.2	-573.3
Daiwa Capital Markets America	2.4	1.7	4.1	1.7	1.7	3.1	2.8	4.9	1.3	0.8	2.5	4.8	1.16	17.1	-622.0
Fannie Mae	2.4	1.6	4.0	1.7	2.1	2.5	2.7	2.7	2.4	0.7	2.4 L	4.8	1.23	17.5	-563.5
Moody's Capital Markets*	2.4	1.5	3.9	1.3 L	2.0	2.4	2.7	2.6	1.5	0.6	2.5	4.8	1.20	17.2	-578.8
Point72 Asset Management	2.4	1.8	4.3	1.9	2.1	2.8	2.6	4.7	0.9	1.0	2.8	4.4 L	1.25	17.5	-575.5
Regions Financial Corporation	2.4	1.7	4.2	1.5	1.9	2.7	2.9	3.7	3.3	0.5	2.6	5.0	1.17	17.4	-573.3
Wells Fargo	2.4	1.6	4.0	1.9	1.4	2.8	2.8	4.6	6.2	0.8	2.4 L	4.7	1.25	17.5	-636.5
ACT Research	2.3	1.9	4.3	1.7	1.2	2.8	2.6	4.0	na	0.7	2.6	4.8	1.29	18.3	-605.3
Goldman Sachs & Co.**	2.3	1.6	3.9	1.8	1.9	2.9	2.8	3.4	na	0.9	2.8	4.7	1.27	na	-646.4
J P MorganChase	2.3	1.8	4.1	1.7	2.1	2.8	2.6	5.1	3.6	na	na	4.7	1.20	17.5	-592.5
Morgan Stanley*	2.3	1.8	4.1	1.7	2.1	2.8	2.6	5.1	3.6	na	na	4.7	1.20	17.5	-592.5
RBS Securities	2.3	1.6	3.9	2.0	1.6	2.9	2.8	4.6	3.5	0.8	2.8	4.7	1.35	17.0	-606.0
AIG	2.2	1.6	3.9	1.6	1.8	2.1	2.5 L	2.8	0.8	0.6	2.4 L	5.0	1.27	16.9	-548.0
Eaton Corporation	2.2	1.8	4.0	1.8	2.2	2.4	3.5 H	3.3	4.6	0.6	3.0	4.9	1.23	17.2	-648.9
Nomura Securities	2.2	1.6	3.7 L	1.6	1.2	3.2	2.7	4.4	na	0.7	2.4 L	4.7	1.23	17.7	-612.2
Econoclast	2.1	1.6	3.7 L	2.4	1.8	2.6	2.6	3.8	3.5	0.5	2.5	4.9	1.13	17.5	-565.0
BNP Paribas North America	2.0 L	na	na	1.8	1.6	3.0	2.5 L	3.3	na	na	2.7	4.7	1.20	na	-615.0
2016 Consensus: December Avg.	**2.5**	**1.7**	**4.3**	**1.8**	**1.9**	**2.9**	**2.8**	**4.3**	**4.0**	**0.8**	**2.7**	**4.8**	**1.25**	**17.6**	**-590.5**
Top 10 Avg.	2.9	2.1	4.9	2.2	2.7	3.6	3.2	5.9	8.0	1.1	3.1	5.0	1.36	18.2	-552.5
Bottom 10 Avg.	2.2	1.5	3.9	1.5	1.3	2.4	2.6	2.9	0.3	0.5	2.4	4.5	1.16	17.0	-632.7
November Avg.	2.6	1.8	4.4	1.8	2.1	2.7	2.9	4.2	4.0	0.7	2.7	4.8	1.28	17.4	-588.2
Number Of Forecasts Changed From A Month Ago:															
Down	18	12	22	21	31	6	25	21	22	8	8	20	25	3	29
Same	24	30	17	21	6	6	18	11	4	20	15	25	21	16	3
Up	9	8	11	9	12	35	8	19	12	17	25	6	5	24	19
December Median	2.5	1.7	4.3	1.7	1.9	2.9	2.8	4.2	3.9	0.7	2.7	4.7	1.25	17.5	-587.3
December Diffusion Index	41 %	46 %	39 %	38 %	31 %	81 %	33 %	48 %	37 %	60 %	68 %	36 %	30 %	74 %	40 %

***Former winner of annual Lawrence R. Klein Award for Blue Chip Forecast Accuracy. **Denotes two-time winner. ***Denotes three-time winner.**

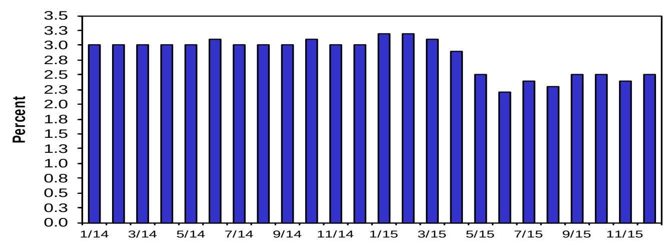
BASIC DATA SOURCES: [1]Gross Domestic Product (GDP), chained 2009$, National Income and Product Accounts (NIPA), Bureau of Economic Analysis (BEA); [2]GDP Chained Price Index, NIPA, BEA; [3]GDP, current dollars, NIPA, BEA; [4]Consumer Price Index-All Urban Consumers, Bureau of Labor Statistics (BLS); [5]Total Industrial Production, Federal Reserve Board (FRB); [6]Disposable Personal Income, 2009$, NIPA, BEA; [7]Personal Consumption Expenditures, 2009$, NIPA, BEA; [8]Nonresidential Fixed Investment, 2009$, NIPA, BEA; [9]Corporate Profits Before Taxes, current dollars, with inventory valuation and capital consumption adjustments, NIPA, BEA; [10]Treasury Bill Rate, 3-month, secondary market, bank discount basis, FRB; [11]Treasury note yield, 10-year, constant maturity basis, FRB; [12]Unemployment Rate, civilian work force, BLS; [13]Housing Starts, Bureau of Census; [14]Total U.S. Auto and Light Truck Sales (includes imports), BEA; [15]Net Exports of Goods and Services, 2009$, NIPA, BEA.

Previous Consensus Forecasts

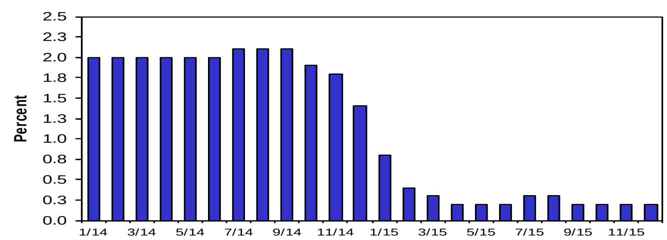
Consensus Forecasts For 2015	Real GDP Chained ('2009$)	GDP Price Index	Nominal GDP (Cur. $)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income ('2009$)	Personal Cons. Exp. ('2009$)	Non-Res. Fix. Inv. ('2009$)	Corp. Profits (Cur. $)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto/Truck Sales (Mil.)	Net Exports ('2009$)
January 2014 Consensus	3.0	1.9	4.9	2.0	3.5	2.8	2.8	5.4	5.0	0.5	3.7	6.3	1.30	16.5	-418.5
February 2014 Consensus	3.0	1.9	4.9	2.0	3.5	2.8	2.8	5.6	5.1	0.5	3.7	6.1	1.31	16.4	-388.2
March 2014 Consensus	3.0	1.9	4.9	2.0	3.6	2.8	2.8	5.7	5.4	0.5	3.7	5.9	1.31	16.4	-392.9
April 2014 Consensus	3.0	1.9	4.9	2.0	3.6	2.9	2.9	5.7	5.6	0.5	3.7	5.9	1.31	16.4	-398.5
May 2014 Consensus	3.0	1.9	4.9	2.0	3.6	2.9	2.9	5.7	5.2	0.5	3.6	5.9	1.27	16.4	-410.7
June 2014 Consensus	3.1	1.9	5.0	2.0	3.6	2.9	2.8	5.7	6.0	0.5	3.5	5.8	1.26	16.5	-421.4
July 2014 Consensus	3.0	1.9	5.0	2.1	3.6	2.8	2.8	5.6	5.8	0.5	3.5	5.8	1.23	16.6	-436.4
August 2014 Consensus	3.0	1.9	5.0	2.1	3.7	2.8	2.8	5.5	5.8	0.5	3.4	5.7	1.20	16.7	-456.4
September 2014 Consensus	3.0	2.0	5.0	2.1	3.6	2.8	2.7	5.7	6.4	0.5	3.3	5.7	1.20	16.7	-455.1
October 2014 Consensus	3.1	1.9	5.0	1.9	3.5	2.9	2.7	6.0	6.6	0.5	3.2	5.6	1.19	16.8	-450.1
November 2014 Consensus	3.0	1.8	4.8	1.8	3.6	2.8	2.7	5.8	6.5	0.4	3.0	5.6	1.18	16.8	-436.1
December 2014 Consensus	3.0	1.7	4.7	1.4	3.5	2.9	2.8	5.9	7.0	0.4	2.9	5.5	1.17	16.8	-448.2
January 2015 Consensus	3.2	1.5	4.7	0.8	3.8	3.1	3.0	5.9	7.0	0.4	2.7	5.5	1.17	16.9	-457.3
February 2015 Consensus	3.2	1.1	4.3	0.4	3.9	3.3	3.3	5.1	6.3	0.4	2.4	5.4	1.16	16.9	-475.5
March 2015 Consensus	3.1	1.1	4.3	0.3	3.8	3.5	3.3	5.3	5.6	0.3	2.4	5.4	1.16	16.9	-491.2
April 2015 Consensus	2.9	1.1	4.0	0.2	3.1	3.5	3.2	5.0	4.3	0.3	2.3	5.4	1.14	16.8	-493.5
May 2015 Consensus	2.5	1.0	3.5	0.2	2.5	3.5	3.1	3.5	3.3	0.2	2.2	5.4	1.11	16.8	-522.2
June 2015 Consensus	2.2	1.0	3.3	0.2	2.3	3.4	2.9	3.6	1.4	0.2	2.3	5.4	1.10	16.9	-542.5
July 2015 Consensus	2.4	1.0	3.4	0.3	2.0	3.4	3.0	3.5	1.3	0.2	2.3	5.3	1.11	16.9	-547.7
August 2015 Consensus	2.3	1.1	3.4	0.3	1.9	3.2	3.0	2.8	1.4	0.2	2.3	5.3	1.12	17.0	-542.0
September 2015 Consensus	2.5	1.1	3.6	0.2	1.8	3.2	3.0	3.4	0.6	0.1	2.2	5.3	1.13	17.1	-539.0
October 2015 Consensus	2.5	1.1	3.6	0.2	1.6	3.2	3.2	3.6	1.2	0.1	2.2	5.3	1.13	17.2	-546.9
November 2015 Consensus	2.4	1.0	3.5	0.2	1.5	3.2	3.2	3.3	0.8	0.1	2.2	5.3	1.13	17.3	-540.7
December 2015 Consensus	**2.5**	**1.0**	**3.5**	**0.2**	**1.6**	**3.5**	**3.1**	**3.3**	**-0.2**	**0.1**	**2.2**	**5.3**	**1.11**	**17.4**	**-543.4**
Change From Jan. 2014 Forecast	-0.5	-0.9	-1.4	-1.8	-1.9	0.7	0.3	-2.1	-5.2	-0.4	-1.5	-1.0	-0.19	0.9	-124.9
Forecast High	3.2	2.0	5.0	2.1	3.9	3.5	3.3	6.0	7.0	0.5	3.7	6.3	1.31	17.4	-388.2
Forecast Low	2.2	1.0	3.3	0.2	1.5	2.8	2.7	2.8	-0.2	0.1	2.2	5.3	1.10	16.4	-547.7

Consensus Forecasts For 2016	Real GDP Chained ('2009$)	GDP Price Index	Nominal GDP (Cur. $)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income ('2009$)	Personal Cons. Exp. ('2009$)	Non-Res. Fix. Inv. ('2009$)	Corp. Profits (Cur. $)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto/Truck Sales (Mil.)	Net Exports ('2009$)
January 2015 Consensus	2.9	2.0	4.9	2.3	3.3	2.8	2.7	5.4	4.1	1.7	3.5	5.1	1.30	17.0	-480.4
February 2015 Consensus	2.9	2.0	4.9	2.3	3.3	2.8	2.8	5.2	4.1	1.6	3.2	5.0	1.30	17.1	-499.5
March 2015 Consensus	2.9	1.9	4.8	2.2	3.2	2.7	2.8	5.2	4.1	1.6	3.2	5.0	1.30	17.0	-523.7
April 2015 Consensus	2.8	1.9	4.8	2.2	3.1	2.6	2.8	5.2	4.0	1.4	3.1	5.0	1.28	17.0	-530.0
May 2015 Consensus	2.8	1.9	4.8	2.2	3.1	2.5	2.8	5.0	3.9	1.3	3.0	5.0	1.26	17.1	-544.4
June 2015 Consensus	2.8	1.9	4.8	2.2	3.0	2.5	2.8	5.0	4.4	1.2	3.0	4.9	1.26	17.1	-573.8
July 2015 Consensus	2.8	1.9	4.8	2.2	2.9	2.5	2.8	4.9	4.1	1.2	3.0	4.9	1.27	17.1	-578.5
August 2015 Consensus	2.7	1.9	4.7	2.1	2.7	2.6	2.9	4.7	4.0	1.1	2.9	4.9	1.27	17.1	-573.7
September 2015 Consensus	2.7	1.9	4.6	2.0	2.6	2.6	2.9	4.8	4.1	1.0	2.9	4.8	1.28	17.2	-569.1
October 2015 Consensus	2.7	1.8	4.5	2.0	2.3	2.6	2.9	4.8	4.2	0.8	2.7	4.8	1.28	17.3	-591.4
November 2015 Consensus	2.6	1.8	4.4	1.8	2.1	2.7	2.9	4.2	4.0	0.7	2.7	4.8	1.28	17.4	-588.2
December 2015 Consensus	**2.5**	**1.7**	**4.3**	**1.8**	**1.9**	**2.9**	**2.8**	**4.3**	**4.0**	**0.8**	**2.7**	**4.8**	**1.25**	**17.6**	**-590.5**
Change From Jan. 2015 Forecast	-0.4	-0.3	-0.6	-0.5	-1.4	0.1	0.1	-1.1	-0.1	-0.9	-0.8	-0.3	-0.05	0.6	-110.1
Forecast High	2.9	2.0	4.9	2.3	3.3	2.9	2.9	5.4	4.4	1.7	3.5	5.1	1.30	17.6	-480.4
Forecast Low	2.5	1.7	4.3	1.8	1.9	2.5	2.7	4.2	3.9	0.7	2.7	4.8	1.25	17.0	-591.4

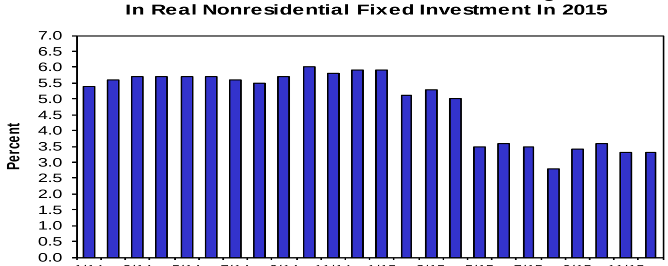
Consensus Forecasts Of Y/Y % Change In Real GDP In 2015



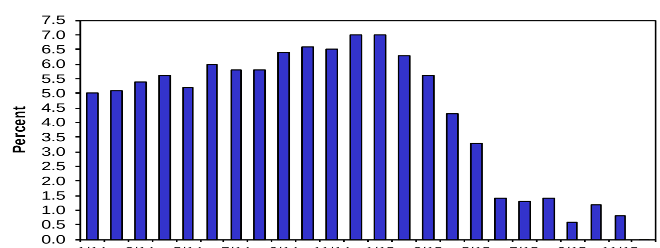
Consensus Forecasts Of Y/Y % Change In Consumer Price Index In 2015



Consensus Forecasts Of Y/Y % Change In Real Nonresidential Fixed Investment In 2015



Consensus Forecasts Of Y/Y % Change In Corporate Profits In 2015



3. Blue Chip Consensus: Percent Change From Prior Quarter At Annual Rate And Averages For Quarter.*

Actuals[1]	Real GDP	GDP Price Index	CPI	Producer Price Index	Total Industrial Production	Disposable Personal Income	Personal Consump. Expend.	Unemploy-ment Rate	3-Mo. Treas. Bills	10-Yr. Treas. Notes	Change in Business Inventories	Real Net Exports
	% Change From Prior Quarter At Annual Rate							Average For Quarter				
2014 1Q	-0.9	1.5	2.1	2.3	3.6	4.0	1.3	6.6	0.1	2.8	36.9	-434.0
2Q	4.6	2.2	2.4	2.2	5.7	3.0	3.8	6.2	0.1	2.6	77.1	-443.3
3Q	4.3	1.6	1.2	1.2	3.9	2.7	3.5	6.1	0.0	2.6	79.9	-429.1
4Q	2.1	0.1	-0.9	-0.6	4.7	4.7	4.3	5.7	0.0	2.3	78.2	-463.6
2015 1Q	0.6	0.1	-3.1	-4.8	-0.3	3.9	1.8	5.6	0.0	2.0	112.8	-541.2
2Q	3.9	2.1	3.0	1.1	-2.3	2.6	3.6	5.4	0.0	2.2	113.5	-534.6
3Q	2.1	1.3	1.6	1.0	2.6	3.9	3.0	5.2	0.0	2.2	90.2	-544.1
Blue Chip Forecasts	% Change From Prior Quarter At Annual Rate							Average For Quarter				
4Q Consensus	**2.2**	**1.3**	**0.6**	**-1.9**	**0.7**	**3.4**	**2.7**	**5.0**	**0.1**	**2.2**	**66.6**	**-552.3**
Top 10 Avg.	2.9	1.7	1.5	1.6	2.8	4.5	3.4	5.1	0.3	2.3	82.1	-534.8
Bot. 10 Avg.	1.6	0.7	-0.2	-5.4	-1.2	2.3	2.2	5.0	0.1	2.2	50.0	-571.3
2016 1Q Consensus	**2.5**	**1.8**	**1.6**	**1.6**	**2.4**	**2.7**	**2.8**	**4.9**	**0.4**	**2.5**	**64.5**	**-567.9**
Top 10 Avg.	3.0	2.4	2.2	3.1	3.4	3.6	3.2	5.1	0.6	2.7	82.6	-543.6
Bot. 10 Avg.	2.1	1.3	0.8	0.3	1.3	2.0	2.3	4.8	0.2	2.3	45.6	-596.5
2Q Consensus	**2.7**	**2.0**	**2.2**	**2.3**	**2.6**	**2.5**	**2.8**	**4.8**	**0.6**	**2.6**	**64.2**	**-582.3**
Top 10 Avg.	3.3	2.4	3.0	3.4	3.5	3.2	3.3	5.0	0.9	3.0	84.8	-548.3
Bot. 10 Avg.	2.3	1.7	1.6	1.4	1.9	1.9	2.4	4.6	0.4	2.4	42.8	-619.1
3Q Consensus	**2.6**	**2.0**	**2.3**	**2.3**	**2.7**	**2.5**	**2.8**	**4.7**	**0.9**	**2.8**	**60.8**	**-597.3**
Top 10 Avg.	3.1	2.4	3.2	3.3	3.5	3.2	3.4	5.0	1.2	3.2	80.4	-552.2
Bot. 10 Avg.	2.2	1.6	1.8	1.4	1.9	1.9	2.4	4.4	0.6	2.5	38.7	-645.5
4Q Consensus	**2.6**	**2.0**	**2.4**	**2.4**	**2.7**	**2.6**	**2.7**	**4.6**	**1.1**	**2.9**	**60.0**	**-611.8**
Top 10 Avg.	2.9	2.5	3.3	3.4	3.4	3.2	3.4	4.9	1.6	3.5	81.5	-558.6
Bot. 10 Avg.	2.2	1.6	1.8	1.7	2.0	2.0	2.2	4.3	0.7	2.5	36.9	-672.0

4. Blue Chip Consensus: Quarterly Annualized Values And Percent Change From Same Quarter In Prior Year.*

Real Gross Domestic Product

	Billions Of Chained 2009$ (SAAR)			% Change From Same Quarter **In Prior Year**[2]		
	Actual	**Forecast**[1]		Actual	**Forecast**	
Quarter	2014	2015	2016	2014	2015	2016
1Q	15724.9	16177.3	**16612.5**	1.7	2.9	**2.7**
2Q	15901.5	16333.6	**16723.1**	2.6	2.7	**2.4**
3Q	16068.8	16417.8	**16830.7**	2.9	2.2	**2.5**
4Q	16151.4	**16509.0**	**16937.7**	2.5	**2.2**	**2.6**

GDP Chained Price Index

	Index 2009 = 100 (SAAR)			% Change From Same Quarter **In Prior Year**[2]		
	Actual	**Forecast**[1]		Actual	**Forecast**	
Quarter	2014	2015	2016	2014	2015	2016
1Q	108.0	109.1	**110.9**	1.6	1.0	**1.6**
2Q	108.6	109.7	**111.4**	1.9	1.0	**1.6**
3Q	109.0	110.0	**112.0**	1.8	0.9	**1.8**
4Q	109.1	**110.4**	**112.5**	1.3	**1.2**	**1.9**

Total Industrial Production

	Index 2012 = 100 (SAAR)			% Change From Same Quarter **In Prior Year**[2]		
	Actual	**Forecast**[1]		Actual	**Forecast**	
Quarter	2014	2015	2016	2014	2015	2016
1Q	103.8	107.4	**108.3**	2.5	3.5	**0.9**
2Q	105.3	106.8	**109.0**	3.6	1.4	**2.1**
3Q	106.3	107.5	**109.7**	4.2	1.1	**2.1**
4Q	107.5	**107.7**	**110.5**	4.5	**0.2**	**2.6**

Consumer Price Index

	Index 1982-1984 = 100 (SAAR)			% Change From Same Quarter **In Prior Year**[2]		
	Actual	**Forecast**[1]		Actual	**Forecast**	
Quarter	2014	2015	2016	2014	2015	2016
1Q	235.4	235.2	**239.2**	1.4	-0.1	**1.7**
2Q	236.8	236.9	**240.5**	2.1	0.0	**1.5**
3Q	237.5	237.9	**241.9**	1.8	0.1	**1.7**
4Q	237.0	**238.2**	**243.3**	1.2	**0.5**	**2.1**

***See explanatory notes on inside of back cover for details of how this data is compiled.**

BLUE CHIP INTERNATIONAL CONSENSUS FORECASTS

	ANNUAL DATA						END OF YEAR			
	Real Economic Growth % Change GDP		Inflation % Change Consumer Prices		Current Account In Billions Of U.S. Dollars		Exchange Rate [1] Against U.S. $		Interest Rates 3-Month	
CANADA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**1.3**	**2.0**	**1.0**	**1.8**	**-52.4**	**-43.4**	**1.31**	**1.30**	**0.62**	**1.01**
Top 3 Avg.	1.5	2.5	1.3	2.2	-49.0	-40.1	1.36	1.38	0.77	1.29
Bottom 3 Avg.	1.0	1.6	0.5	1.3	-55.4	-49.9	1.25	1.20	0.44	0.62
Last Month Avg.	1.1	2.1	1.2	1.9	-54.8	-46.0	1.32	1.30	0.61	1.08
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.0	2.4	1.0	1.9	-54.6	-37.5	1.33	1.14	0.78	1.17
MEXICO	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**2.4**	**2.7**	**2.8**	**3.2**	**-30.9**	**-27.7**	**16.66**	**16.72**	**3.33**	**3.93**
Top 3 Avg.	2.5	3.1	3.0	3.7	-27.1	-15.2	17.02	17.31	3.53	4.18
Bottom 3 Avg.	2.1	2.3	2.6	2.7	-34.8	-37.7	15.97	15.96	3.14	3.68
Last Month Avg.	2.3	2.7	2.9	3.5	-29.1	-25.4	16.59	16.61	3.41	4.01
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.4	2.1	3.8	4.0	-30.5	-25.0	16.00	14.10	3.34	3.29
JAPAN	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**0.6**	**1.0**	**0.8**	**0.7**	**120.0**	**114.3**	**122.9**	**124.5**	**0.10**	**0.10**
Top 3 Avg.	0.8	1.5	1.3	1.4	133.0	160.8	127.0	133.7	0.16	0.19
Bottom 3 Avg.	0.5	0.5	0.4	0.4	95.0	74.2	119.6	113.2	0.04	0.04
Last Month Avg.	0.6	1.1	0.8	0.8	115.7	99.5	122.6	126.6	0.09	0.10
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.6	-0.1	0.4	2.7	40.7	24.4	123.0	120.0	0.08	0.11
UNITED KINGDOM	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**2.4**	**2.3**	**0.1**	**1.2**	**-134.2**	**-136.0**	**1.52**	**1.53**	**0.58**	**1.08**
Top 3 Avg.	2.4	2.5	0.1	1.6	-124.4	-117.6	1.56	1.59	0.70	1.42
Bottom 3 Avg.	2.4	1.9	0.0	0.8	-147.4	-164.8	1.49	1.45	0.46	0.69
Last Month Avg.	2.5	2.3	0.2	1.3	-134.0	-121.0	1.52	1.52	0.57	1.18
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.7	3.0	2.6	1.5	-119.8	-173.9	1.49	1.56	0.57	0.53
SOUTH KOREA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**2.6**	**2.9**	**0.7**	**1.6**	**103.9**	**95.7**	**1174**	**1203**	**1.57**	**1.67**
Top 3 Avg.	2.7	3.3	1.0	2.4	111.5	110.1	1212	1263	1.64	1.97
Bottom 3 Avg.	2.5	2.4	0.6	0.8	89.9	81.0	1135	1131	1.50	1.41
Last Month Avg.	2.4	2.9	0.8	1.6	101.7	91.6	1186	1193	1.56	1.76
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.9	3.3	1.3	1.3	61.6	84.3	1164	1113	1.72	2.08
GERMANY	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**1.5**	**1.8**	**0.3**	**1.2**	**271.0**	**257.1**	**1.09**	**1.04**	**-0.02**	**0.01**
Top 3 Avg.	1.6	2.1	0.5	1.5	281.3	267.5	1.12	1.08	0.02	0.08
Bottom 3 Avg.	1.4	1.5	0.1	0.9	259.9	243.4	1.04	0.99	-0.06	-0.05
Last Month Avg.	1.6	1.8	0.3	1.3	271.4	256.5	1.09	1.03	-0.07	0.01
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	0.4	1.6	1.6	0.8	238.7	286.4	1.05	1.24	-0.12	0.08
TAIWAN	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**1.1**	**2.1**	**-0.1**	**1.2**	**71.4**	**69.5**	**31.23**	**31.92**	**1.14**	**1.32**
Top 3 Avg.	2.0	2.6	0.8	1.8	78.1	75.8	33.80	35.67	1.71	1.75
Bottom 3 Avg.	0.7	1.3	-0.5	0.8	65.9	62.9	23.83	23.87	0.63	0.82
Last Month Avg.	1.4	2.4	-0.2	1.3	72.6	69.1	32.97	33.17	1.07	1.28
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.2	3.8	0.8	1.2	49.6	62.0	32.00	31.10	0.87	0.94
NETHERLANDS	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**2.0**	**1.8**	**0.5**	**1.2**	**75.1**	**73.1**	**1.09**	**1.04**	**-0.02**	**0.01**
Top 3 Avg.	2.2	2.1	0.8	1.3	83.5	85.1	1.12	1.08	0.02	0.08
Bottom 3 Avg.	1.9	1.5	0.2	1.0	67.2	62.3	1.04	0.99	-0.06	-0.05
Last Month Avg.	2.0	1.8	0.5	1.3	76.9	70.9	1.09	1.03	-0.07	0.01
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	-0.7	0.8	2.6	0.3	73.9	88.9	1.05	1.24	-0.12	0.08

*Best estimates available. **In some cases, actual data for 2014 GDP, consumer prices and current account are not yet available. Where it is unavailable, figures are consensus forecasts from December 10, 2014 Blue Chip Economic Indicators. Figures are currency units per U.S. dollar except for U.K., Australia and the Euro.

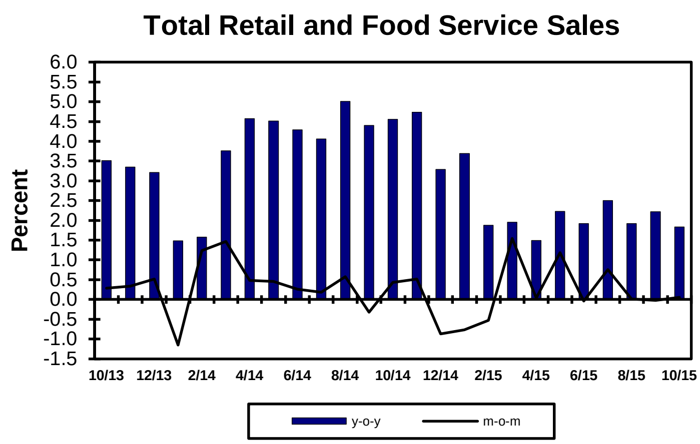
BLUE CHIP INTERNATIONAL CONSENSUS FORECASTS

	ANNUAL DATA						END OF YEAR			
	Real Economic Growth % Change GDP		Inflation % Change Consumer Prices		Current Account In Billions Of U.S. Dollars		Exchange Rate [1] Against U.S. $		Interest Rates 3-Month	
RUSSIA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**-3.8**	**-0.4**	**15.0**	**7.9**	**60.7**	**55.0**	**65.9**	**65.0**	**12.04**	**8.74**
Top 3 Avg.	-3.6	0.4	15.8	9.8	66.4	71.4	71.3	70.0	13.42	9.52
Bottom 3 Avg.	-3.9	-1.2	12.7	6.7	50.0	37.6	60.8	60.6	10.77	8.03
Last Month Avg.	-3.8	-0.5	14.9	7.9	65.9	62.1	65.8	65.5	12.41	8.29
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	1.3	0.6	6.8	7.8	34.1	59.5	66.0	52.9	12.43	12.00
FRANCE	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**1.1**	**1.4**	**0.1**	**0.9**	**-11.5**	**-9.9**	**1.09**	**1.04**	**-0.02**	**0.01**
Top 3 Avg.	1.2	1.6	0.3	1.2	1.5	5.6	1.12	1.08	0.02	0.08
Bottom 3 Avg.	1.0	1.1	0.1	0.3	-25.9	-23.3	1.04	0.99	-0.06	-0.05
Last Month Avg.	1.1	1.3	0.1	1.0	-11.5	-10.1	1.09	1.03	-0.07	0.01
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	0.7	0.2	1.0	0.6	-22.7	-26.2	1.05	1.24	-0.12	0.08
BRAZIL	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**-3.3**	**-2.0**	**8.9**	**7.1**	**-65.5**	**-44.6**	**3.90**	**4.15**	**14.25**	**13.02**
Top 3 Avg.	-2.9	-0.3	9.7	8.1	-59.3	-29.7	4.20	4.52	14.66	13.78
Bottom 3 Avg.	-3.9	-3.6	7.8	6.1	-72.7	-60.3	3.40	3.69	13.85	12.09
Last Month Avg.	-2.8	-1.2	8.7	6.6	-65.8	-48.3	3.91	4.02	14.04	12.85
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.7	0.1	6.2	6.3	-90.9	-103.6	3.86	2.56	14.40	11.80
HONG KONG	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**2.3**	**2.2**	**2.8**	**2.5**	**8.5**	**7.3**	**7.76**	**7.77**	**0.52**	**1.30**
Top 3 Avg.	2.5	2.7	3.0	3.1	12.5	13.1	7.78	7.81	0.66	1.83
Bottom 3 Avg.	2.0	1.5	2.4	1.9	4.3	1.4	7.75	7.75	0.36	0.79
Last Month Avg.	2.2	2.3	2.9	2.7	7.8	6.9	7.76	7.78	0.48	1.11
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	3.1	2.5	4.3	4.4	7.4	6.0	7.75	7.75	0.39	0.38
INDIA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**7.4**	**7.5**	**5.1**	**5.5**	**-24.1**	**-35.6**	**66.0**	**67.6**	**7.20**	**7.05**
Top 3 Avg.	7.7	7.9	5.5	5.8	-16.7	-24.5	68.2	71.1	7.67	7.49
Bottom 3 Avg.	7.2	7.0	4.8	5.0	-33.7	-49.1	63.9	64.6	6.67	6.45
Last Month Avg.	7.4	7.6	5.1	5.5	-25.8	-38.5	66.0	66.6	7.36	7.23
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	6.9	7.3	10.0	5.9	-32.4	-27.5	66.0	61.9	7.16	8.26
CHINA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**6.9**	**6.4**	**1.5**	**1.9**	**339.6**	**341.5**	**6.42**	**6.64**	**3.45**	**3.17**
Top 3 Avg.	7.0	6.6	1.7	2.4	418.1	457.9	6.63	6.90	4.30	3.85
Bottom 3 Avg.	6.8	5.9	1.4	1.4	270.6	237.4	6.26	6.43	2.62	2.42
Last Month Avg.	6.8	6.4	1.6	2.1	346.1	339.5	6.48	6.63	3.32	3.10
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	7.7	7.3	2.6	2.0	148.2	219.7	6.40	6.15	3.04	4.20
AUSTRALIA	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**2.3**	**2.5**	**1.7**	**2.4**	**-59.3**	**-59.0**	**0.71**	**0.70**	**2.17**	**2.38**
Top 3 Avg.	2.5	2.9	2.0	2.8	-43.9	-36.7	0.74	0.73	2.32	2.68
Bottom 3 Avg.	2.1	2.1	1.5	2.1	-85.2	-101.5	0.68	0.66	2.03	2.20
Last Month Avg.	2.3	2.5	1.7	2.5	-52.7	-45.2	0.71	0.71	2.19	2.51
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	2.1	2.7	2.4	2.5	-48.3	-51.3	0.73	0.84	2.62	2.86
EUROZONE	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
December Consensus	**1.5**	**1.7**	**0.1**	**1.0**	**335.5**	**319.6**	**1.08**	**1.06**	**-0.07**	**-0.06**
Top 3 Avg.	1.5	1.9	0.1	1.2	397.8	378.5	1.13	1.15	0.02	0.05
Bottom 3 Avg.	1.5	1.5	-0.1	0.8	266.0	237.1	1.05	0.96	-0.12	-0.15
Last Month Avg.	1.5	1.7	0.1	1.1	357.2	343.8	1.09	1.04	-0.02	0.01
	2013*	2014**	2013*	2014**	2013*	2014**	Latest	Year Ago	Latest	Year Ago
Actual	-0.3	0.9	1.3	0.4	236.6	274.8	1.05	1.24	-0.12	0.08

Contributors to Blue Chip International Survey: IHS Global Insight, US; Barclays, US; Federal Express Corporation, USA; Credit Suisse, US; JP Morgan, US; Economist Intelligence Unit, UK; BMO Capital Markets, Canada; UBS, US; AIG, New York, NY; Oxford Economics, US; Societe Generale, New York, NY; Bank of America-Merrill Lynch, US; Nomura Capital Markets America, US; Morgan Stanley; US; Moody's Capital Markets, US; Eaton, US; Wells Fargo, US; Moody's Analytics, US; Swisse Re, U.S.; Barclays Capital, US; General Motors Corp., US; and Grupo de Economistas y Asociados, Mexico.

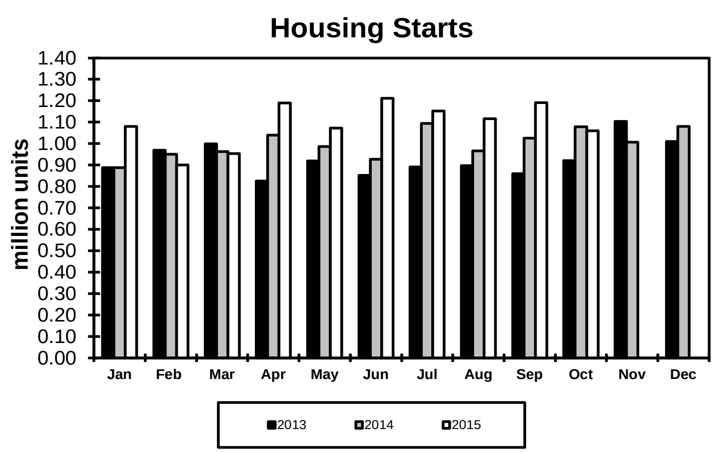
Recent Developments:

Total Retail Sales Up Less Than Expected In October, Held Down By Weak Gasoline Sales



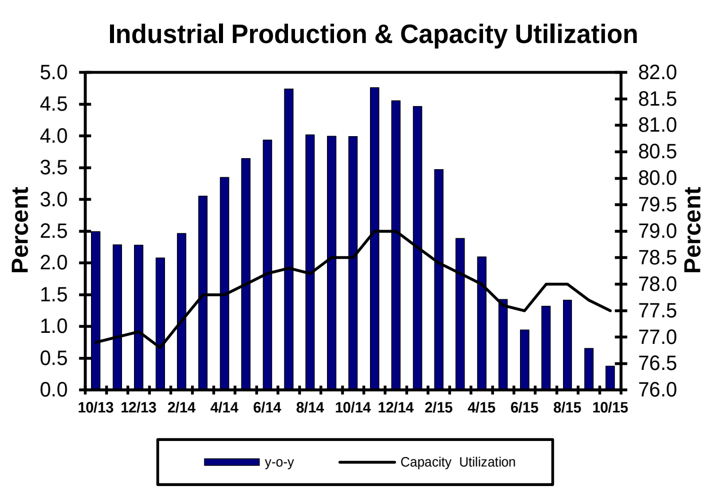
Total retail sales rose a less-than-expected 0.1% in October, the gain capped by declines of 0.9% at gasoline stations as prices fell and 0.5% at auto dealers despite a rise in unit sales of autos and light trucks during the month. The small increase followed unchanged readings for total sales in the prior two months. The soft October increase left total retail sales up just 1.7%, but total sales excluding gasoline were up a more respectable 4.1%. Retail sales excluding autos, building materials and gasoline—the component that feeds into the calculation of non-auto consumer goods spending within GDP—rose 0.2% in October after revised increases of 0.1% in September and 0.2% in August. They were up 2.9% on a y/y basis. Elsewhere, apparel sales were flat in October, hurt in part by warmer than unusual temperatures, while the warmer temps may have helped boost sales at eating and drinking establishments that rose 0.5%. Sales at building materials outlets jumped 0.9% after falling in the prior two months. Total retail sales in November likely eked out a modest increase of 0.3% despite a further decline in sales at gasoline stations and little change in auto sales.

Housing Activity Mixed In October



Total housing starts fell a larger-than-expected 11.0% in October to an annual rate of 1.060 million units. Most of the decline was accounted for by a 25.1% plunge in multi-family starts while starts of single-family homes fell only 2.4%. On a y/y basis, total starts were down 1.8% in October, single-family starts up 2.4%, and multi-family starts down 9.6%. Total permits rose 4.1% in October, lifted by a 2.4% increase for single-family permits and a 6.8% jump in permits for multi-family. On a y/y basis, total permits were up 2.7%, single-family up 9.0%, but multi-family down 6.2%. New home sales rebounded 10.7% in October to an annual rate of 495,000 units, partially reversing the 12.9% decline in September. Sales were up 4.9% on a y/y basis. The median sales price of a new home sold in October was down 6.0% compared to a year ago. Sales of existing homes fell by 3.4% in October to an annual rate of 5.36 million units. Sales of single-family downs dropped 3.7% while sales of condos/co-ops were down 1.6%. Median total resale prices were up 5.8% y/y in October, with the single-family median prices 6.3% above the year-ago level.

Weak Utility and Mining Output Held Down Industrial Production In October



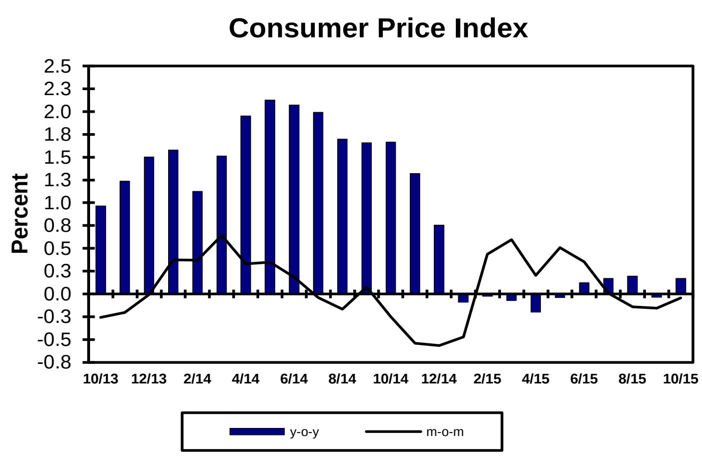
Total industrial production was weaker-than-expected in October, falling 0.2%. Manufacturing output actually increased 0.4% in October, but mining and utility output fell 1.5% and 2.5%, respectively. On a y/y basis, total industrial production was up only 0.3% in October, with manufacturing up 1.9%, but mining output down 6.9% and utility output off by 1.5%. Supporting manufacturing in October was a 0.7% jump in vehicle production that followed a 0.5% gain the month before. On a y/y basis vehicle production was up 10.9% in October. Elsewhere, production of computer and office equipment fell 0.3% in October but was up 5.8% y/y. Production of high-tech equipment rose 0.7% in October , but up only 0.1% y/y. The capacity utilization rate slipped to 77.5% in October from 77.7% the month before. The Institute of Supply Management's index of activity in the manufacturing sector fell from 50.1 in October to 48.6 in November, marking its lowest reading since June 2009. The new orders (48.9) and production (49.2) indices also fell below the 50 level, signaling contractions. A strong dollar, extreme weakness in the oil and gas sector, and general cautiousness about capital spending continues to weigh on the manufacturing sector.

Recent Developments:

Trade Deficit Widened More Than Expected In October

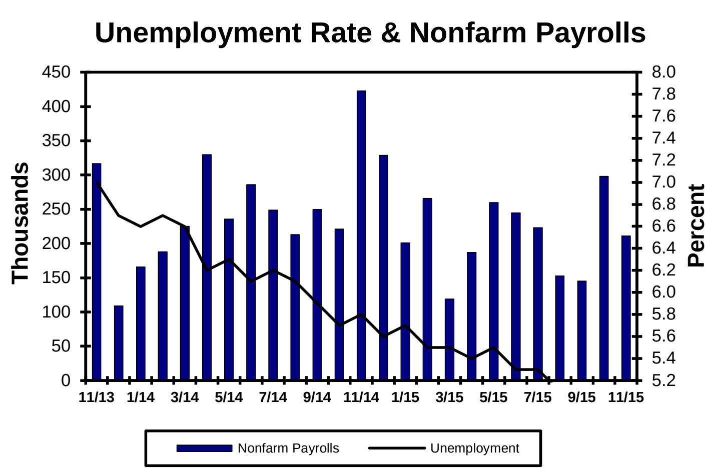
The trade deficit widened a bit more than expected in October, suggesting that the trade sector will gain subtract from GDP growth in Q4. In Q3, real net exports subtracted 0.22 of a percentage point from real GDP's rate of growth. The goods and services deficit increased to $43.9 billion during October in nominal terms from $42.5 billion in September. Nominal exports fell 1.4% in October, while nominal imports dropped 0.6%. The real (inflation-adjusted) deficit widened to $60.3 billion from $57.4 billion as real exports fell 2.4% while real imports were unchanged. On a y/y basis, real exports were down 3.2% in November, while real imports were off by 3.7%. Exports of consumer goods were down 2.9% in October and unchanged y/y, while imports of consumer goods rose 0.4% in October, but up a strong 10.0% y/y. Real exports of capital goods fell 2.2% in October and were down 6.6% y/y, while imports of capital goods rose 1.1% in October, but were up just 0.5% y/y. The strength in imports versus exports over the past year reflects the impact of the run-up in the trade-weighted value of the U.S. dollar over the past year combined with the relative strength of domestic demand in America compared to that in our major trading partners.

October Consumer Price Index About As Expected, But Core CPI Rose By More Than Anticipated



The Consumer Price Index increased an about as expected 0.2% in October, but the core CPI (excludes food and energy prices) rose a greater than expected 0.2% for a second consecutive month. The October increases left the overall CPI up 0.2% y/y versus unchanged the month before and the core CPI up 1.9% y/y for a second month running. Energy prices increased 0.3% in October but were still down 17.1% y/y, while food prices rose 0.1% and were up 1.6% y/y. Within the broad energy group, gasoline and electricity prices both rose 0.4% in October, but natural gas prices were down 0.7%. Rent of primary residence rose 0.3% in October and was up 3.7% y/y, while owners' equivalent rent increased 0.2% and was up 3.1% y/y. The November change in the CPI will likely be capped by lower gasoline prices. However, over the next few months the effects of the sharp plunge in oil prices between the summer of 2014 and January 2015 will start to roll off and the y/y change in the overall CPI will begin to converge with the core CPI in relatively rapid fashion barring a sharp, renewed plunge in crude oil prices.

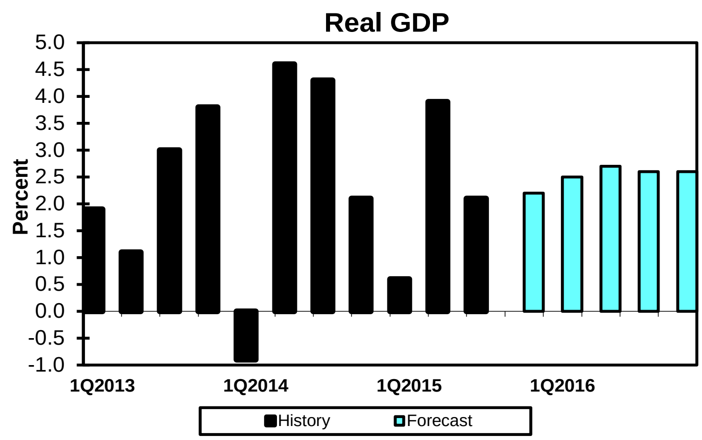
November Employment Report Likely Green-Lighted A FOMC Rate Hike In December



The November Employment Report was modestly stronger than market expectations and solid enough to green-light a December rate hike by the Federal Reserve. Nonfarm payrolls grew by 211,000 in November and revisions added a cumulative 35,000 to payroll gains in the prior two months. Private payrolls increase by 197,000 in November. Average payroll gains over the past three months averaged 218,000, virtually identical to the 12-month average of 220,000. The 3-month average gain for private payrolls was 222,000, up a bit from its 12-month average of 212,000. The unemployment rate remained at 5.0% in November as an uptick in the labor force participation rate to 62.5% from 62.4% offset a healthy increase in household employment of 244,000 that followed an even larger increase of 320,000 in October. However, the U-6 unemployment rate ticked up to 9.9% from 9.8% as involuntary part-time workers increased 261,000. Average hourly earnings increased 0.2% dropping the y/y change to 2.3% from 2.5% in October. Private-sector hours worked slipped 0.1% but hours of production workers increased 0.2% while manufacturing hours were unchanged.

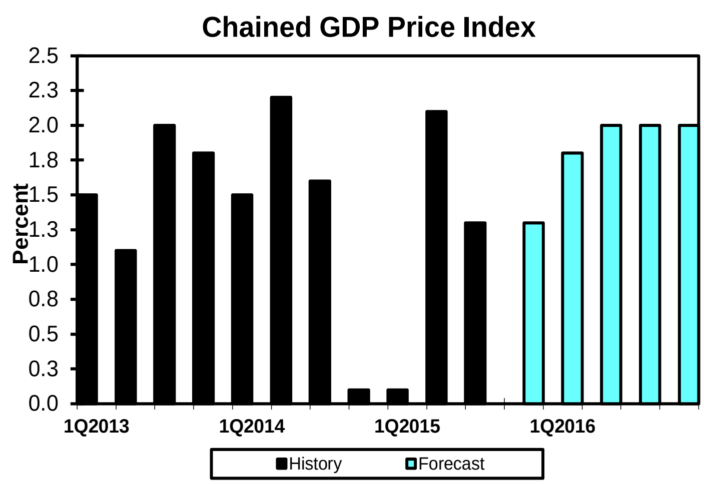
Quarterly U.S. Forecasts:

Real GDP



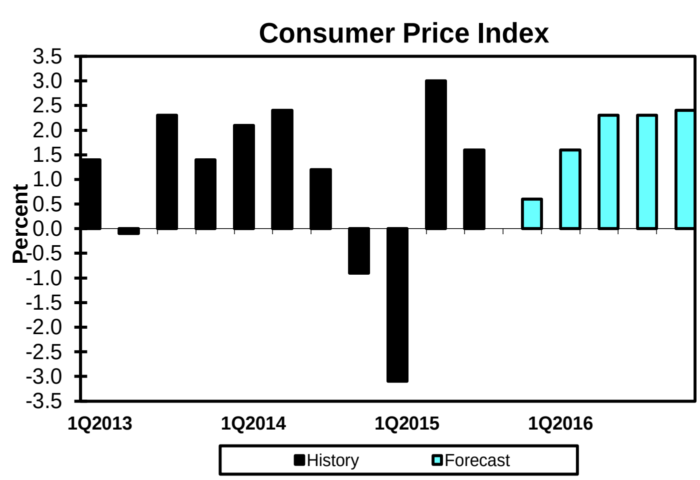
Real GDP grew an upwardly revised 2.1% (q/q,saar) in Q3, according to BEA's second estimate, 0.6 of a percentage point faster than its initial guess and much closer to what the consensus had expected. The upward revision was entirely accounted for higher inventories as the change in real inventories went to $90.2 billion from $56.8 billion. As a result, inventories now are believed to have subtracted only 0.6 of a percentage point from growth in Q3 rather than the 1.4 points initially thought. Growth in real PCE was revised down a bit, but growth in business fixed investment was revised higher. Real net exports are now estimated to have subtracted a bit more from GDP last quarter than previously thought. Growth during Q3 in real domestic final sales (GDP minus inventories and net exports) were revised to 2.8% versus 2.9%. The consensus forecast of annual real GDP growth in 2015 rebounded to 2.5% this month, but the q4/q4 forecast stayed at 2.2%. The forecast of annual growth in 2016 slipped by 0.1 of a point to 2.5%., but the q4/q4 forecast remained at 2.6%.

Chained GDP Price Index



The GDP price index grew an upwardly revised 1.3% (q/q,saar) in Q3, according to the BEA's second estimate, 0.1 of a percentage point more than the first estimate. That still left it up 0.9% over the past four quarters. The PCE price index also grew an upwardly revised 1.3% (q/q,saar) in Q3. The price index for consumer goods contracted 0.2% (q/q,saar) in Q3 while the price index for consumer services increased 2.0%. Over the last four quarters, the PCE price index was up only 0.3% due to declines in prices for consumer goods while prices for consumer services grew. The price index for business fixed investment increased an upwardly revised 1.7% (q/q,saar) in Q3, bouncing back after two consecutive quarters of contraction. The price index for nonresidential investment increased an upwardly revised 1.2% (q/q,saar), while the price index for residential investment still is estimated to have jumped 3.4%, the largest increase since Q4 of last year. The price index for exports fell 4.2% (q/q,saar) in Q3, while the price index for imports dropped 3.4%. The consensus forecast of the 2015 annual change in the GDP price index stayed at 1.0% this month but the forecast of its 2016 change fell 0.1 of a percentage point to 1.7%.

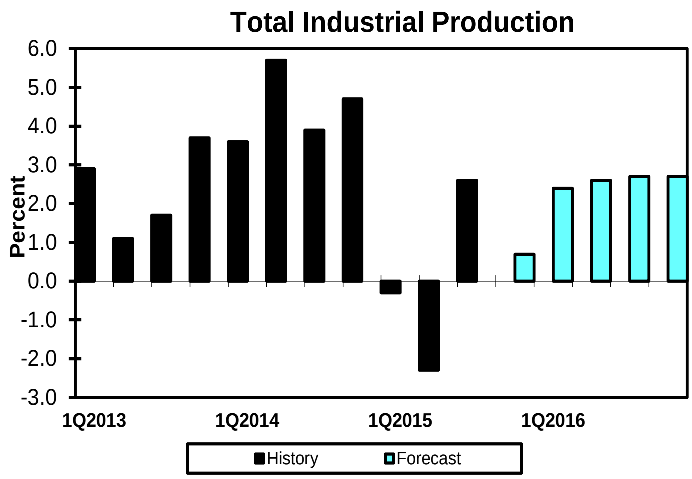
Consumer Price Index



The Consumer Price Index increased an as expected 1.6% (q/q,saar) in Q3, compared with an increase of 3.0% in Q2 and a 3.1% contraction in Q1, the gyrations this year resulting from big swings in energy prices. The core CPI that excludes food and energy prices grew 1.7% (q/q,saar) in Q3 versus 2.5% in Q2 and 1.7% in Q1. As of October, the headline CPI was up 0.2% on a y/y basis, while the core CPI was up 1.9%, its fastest pace since July 2014. The sharp decline in energy prices that began in the summer of 2014 was the primary cause of the softness in headline consumer price inflation over the past year. Total energy prices were down 17.1% y/y in October, with gasoline prices off by 27.8%, and natural gas prices down 11.0%. Food prices were up 1.6% y/y in October, but increased 3.1% at an annual rate over the three months ended in October. Housing costs have lent support to core inflation as owners' equivalent rent was up 3.1% y/y in October and rent of primary residence 3.7% higher. The consensus still expects the headline CPI to increase only 0.2% on an annual basis this year and 1.8% in 2016.

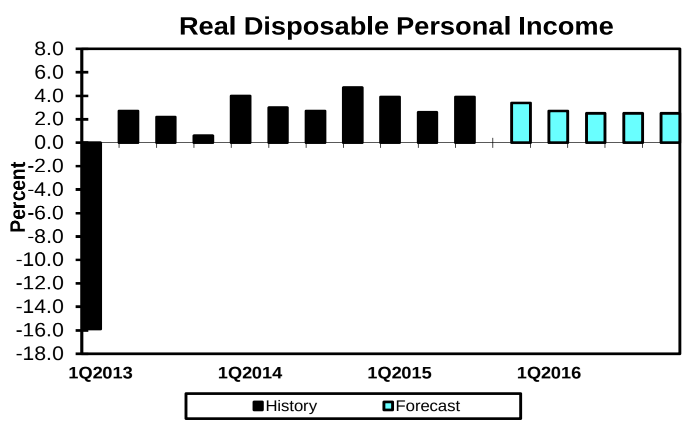
Quarterly U.S. Forecasts:

Industrial Production



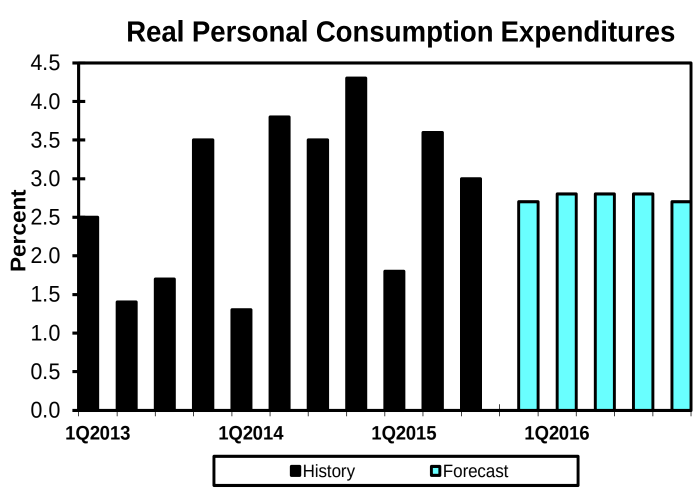
Total industrial production grew an upwardly revised 2.6% (q/q,saar) in Q3, 0.8 of a percentage point more than estimated by the Federal Reserve a month ago. However, it was up only 0.4% on a y/y basis in October. Growth this year has been capped by soft manufacturing output due to weak exports, soft economic growth abroad, and cautious domestic capital spending, coupled with declines in utility and mining output. Manufacturing output grew an upwardly revised 3.3% (q/q,saar) in Q3 after posting an increase of 1.5% in Q2 and a decline of 0.7% in Q1. Contributing especially to the gains over the past two quarters was surging motor vehicle and parts production that increased at annual rates of 14.0% in Q2 and 19.8% in Q3. Utility output increased 2.0% (q/q,saar) after plunging at an annual rate of 12.3% in Q2. Mining output fell 1.0% (q/q,saar) in Q3. The consensus forecast of annual 2015 growth in industrial production rose to 1.6% this month but still expected to increase 0.2% q4/q4. now sees an annual change in total production this year of 1.5% but a q4/q4 change of only 0.2%. Forecasts of its annual and q4/q4 change in 2016 slipped this month to 1.9% and 2.6%, respectively

Real Disposable Personal Income



It now looks as if real disposable personal income (DPI) will register its best annual advance since 2006 in 2015. Real DPI grew an upwardly revised 3.6% (q/q,saar) in Q3, according to BEA's second estimate, 0.1 of a percentage point more than the first estimate. Moreover, growth in Q2 was revised up to 2.6% (q/q,saar) from the 1.2% last reported. The changes left real DPI up a healthy 3.8% over the past four quarters. Nominal growth in DPI this year has steadily accelerated, starting the year with Q1 growth of 1.9% (q/q,saar), rising to upwardly revised rates of 4.9% in Q2 and 5.3% in Q3. Total nominal compensation to employees grew an upwardly revised 5.1% (q/q,saar) in Q3 compared to an upwardly revised 5.3% in Q2 and 3.4% in Q1, while nominal growth in wages and salaries grew an upwardly revised 5.4% in Q3, 5.8% in Q2 and 2.6% in Q1. The consensus forecast of 2015 annual growth in real DPI jumped 0.3 of a percentage point to 3.5% this month and the 2016 forecast 0.2 of a point to 2.9%.

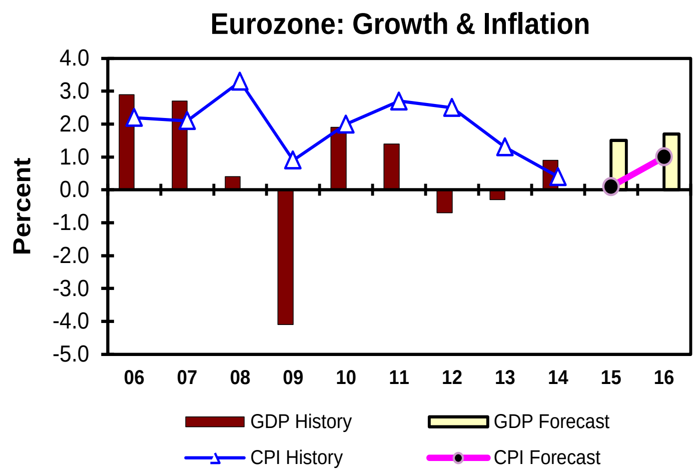
Real Personal Consumption Expenditures



Real personal consumption expenditures (PCE) increased a downwardly revised, but still healthy 3.0% in Q3, according to BEA's second estimate. That is 0.2 of a percentage point less than originally estimated by BEA. Over the past four quarters, real PCE was up 3.2% in Q3. Indeed, real PCE has been up more than 3.0% on a y/y basis for five consecutive quarters, the best performance since prior to the beginning of the 2008-2009 financial crisis. Spending on consumer goods in Q3 increased an upwardly revised 4.8% (q/q,saar). Purchases of durable goods rose 6.5%, while purchases of nondurable goods increased 4.0% a percentage point slower than in Q2. Spending on consumer services grew a downwardly revised 2.2% (q/q,saar) last quarter. Especially beneficial to the acceleration in consumer spending this year has been purchases of cars and light trucks. Indeed, unit sales this year look likely to exceed last year's total by perhaps one million units. Lower inflation this year has helped boost consumer spending by putting more money in consumer pocketbooks. The consensus forecast of real PCE growth this year slipped 0.1 of a percentage point to 3.1%, still making it the best performance since 2005. In 2016, the consensus forecasts an increase of 2.8%, 0.1 of a point less than last month.

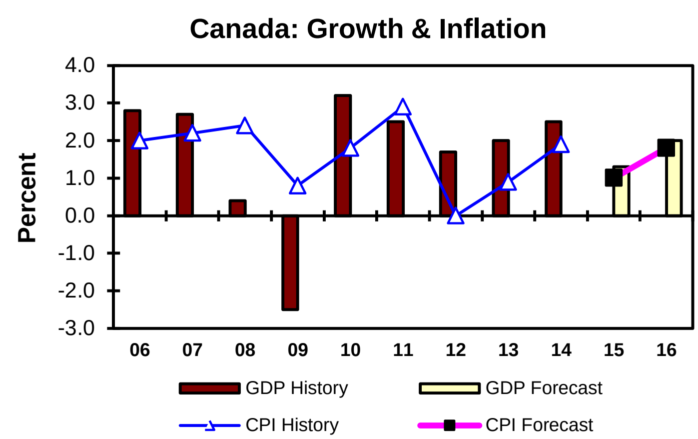
International Forecasts:

Eurozone



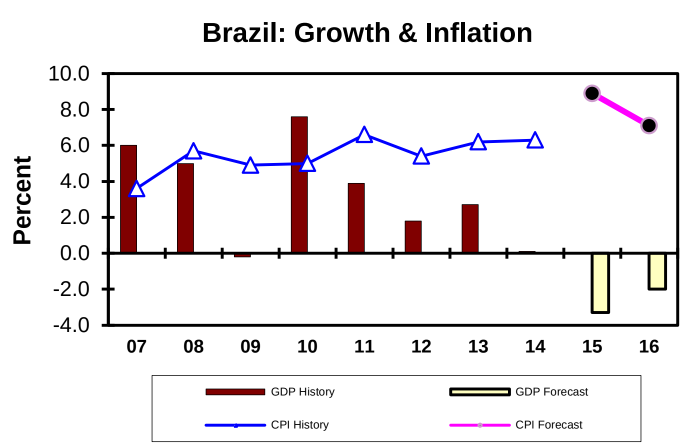
Real GDP in the Eurozone slowed to a less-than-expected 1.2% (q/q,ar) in Q3 from 1.4% in Q2. Consumer spending remained the major catalyst of growth last quarter, while trade was the biggest drag. Real GDP growth in Germany slowed to 1.3% (q/q,ar) in Q3 from 1.8% in Q2, but growth in France improved to 1.4% from 0.2% in Q2. Spain and Portugal also witnessed slower quarterly growth rates in Q3 than in Q2. More recent data has looked a bit stronger, suggesting some upside to estimates of growth in the current quarter. However, the recent attacks in Paris, the continuing refugee crisis, and mounting political uncertainty in Portugal and Spain pose risks to the outlook. The harmonized unemployment rate fell to 10.7% in October, the lowest since January 2012, but varies considerably across nations. Harmonized consumer price inflation rebounded remained at +0.1% (y/y) in November, but the core CPI dropped to 0.9% (y/y) versus 1.1% in October. To fight deflationary trends, the ECB on December 3rd cut the deposit rate further into negative territory and extended its bond-buying program by six months, but markets were unimpressed with the move. The consensus still looks for Eurozone real GDP growth of 1.5% this year and 1.7% in 2016.

Canada



Real GDP grew an about as expected 2.3% (q/q,saar) in Q3. That followed an upwardly revised contraction of -0.3% (q/q,saar) in Q2 and an unrevised fall of -0.7% in Q1. Business investment in Q3 fell for a third straight quarter, the pace of growth in consumer spending moderated compared, but the contribution from trade to GDP improved. Disappointingly, the rebound in Q3 growth ended with a thud as real GDP fell 0.5% in September. That marked the largest monthly decline since the 2009 and suggested little upward momentum as the economy headed into the final quarter of the year. The latest trade and employment reports further hinted that growth prospects in Q4 have dimmed. October's trade deficit unexpectedly widened in October as non-energy exports fell for a third consecutive month to sit 2.3% below year-ago levels. The November employment report showed that payrolls fell by a larger than expected 35,700 and the unemployment rate rose 0.1 of a percentage point to 7.1%. Nonetheless, the consensus forecast of annual real GDP growth in 2015 rose to 1.3% this month, but the forecast of growth in 2016 slipped to 2.0%

Brazil



The situation in Brazil, home to the world's 7th-largest economy, continues to worsen. Real GDP contracted 1.7% in the three months ended in September and was down 4.5% on a y/y basis. The Q3 decline marked the third consecutive quarterly contraction, the first such occurrence since 1996 when the current methodology of calculation was adopted. Investment fell for a ninth straight quarter and consumer spending for three consecutive quarters. The unemployment rate soared to 8.9% in September and consumer price inflation exceeds 10%. To slow inflation and shore up the value of the real that has fallen to record lows against the U.S. dollar, the central bank has raised its overnight policy rate to 14.25%. The economy has been staggered by plunging commodity prices linked to slow global demand and a growing corruption scandal involving state-owned oil company Petrobras that has paralyzed the government and sapped consumer and business confidence. Impeachment of President Dilma Rousseff seems likely and will likely add to the economic uncertainty. The consensus now looks for real GDP to contract 3.3% this year and 2.0% in 2016.

Databank:

2015 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	-0.8	-0.5	1.5	0.0	1.2	0.0	0.8	0.0	0.0	0.1		
Auto & Light Truck Sales (b)	16.63	16.32	17.06	16.70	17.63	16.95	17.47	17.73	18.06	18.12	18.06	
Personal Income (a, current $)	0.2	0.3	0.0	0.6	0.6	0.5	0.4	0.4	0.2	0.4		
Personal Consumption (a, current $)	-0.4	0.2	0.5	0.3	0.9	0.3	0.3	0.3	0.1	0.1		
Consumer Credit (e)	3.6	5.5	7.6	7.6	7.0	9.6	6.8	5.6	10.0			
Consumer Sentiment (U. of Mich.)	98.1	95.4	93.0	95.9	90.7	96.1	93.1	91.9	87.2	90.0	91.3	
Household Employment (c)	759	96	34	192	272	-56	101	196	-236	320	244	
Non-farm Payroll Employment (c)	201	266	119	187	260	245	223	153	145	298	211	
Unemployment Rate (%)	5.7	5.5	5.5	5.4	5.5	5.3	5.3	5.1	5.1	5.0	5.0	
Average Hourly Earnings (All, cur. $)	24.76	24.78	24.85	24.89	24.95	24.95	25.01	25.10	25.12	25.21	25.25	
Average Workweek (All, hrs.)	34.6	34.6	34.5	34.5	34.5	34.5	34.6	34.6	34.5	34.5		
Industrial Production (d)	4.5	3.5	2.4	2.1	1.4	1.0	1.3	1.4	0.7	0.4		
Capacity Utilization (%)	78.7	78.4	78.2	78.0	77.6	77.5	78.0	78.0	77.7	77.5		
ISM Manufacturing Index (g)	53.5	52.9	51.5	51.5	52.8	53.5	52.7	51.1	50.2	50.1	48.6	
ISM Non-Manufacturing Index (g)	56.7	56.9	56.5	57.8	55.7	56.0	60.3	59.0	56.9	59.1	55.9	
Housing Starts (b)	1.080	0.900	0.954	1.190	1.072	1.211	1.152	1.116	1.191	1.060		
Housing Permits (b)	1.059	1.098	1.038	1.140	1.250	1.337	1.130	1.161	1.105	1.150		
New Home Sales (1-family, c)	521	545	485	508	513	469	503	513	447	495		
Construction Expenditures (a)	-1.2	0.6	1.3	3.8	2.3	0.6	0.6	0.9	0.6	1.0		
Consumer Price Index (nsa., d)	-0.1	0.0	-0.1	-0.2	0.0	0.1	0.2	0.2	0.0	0.2		
CPI ex. Food and Energy (nsa., d)	1.6	1.7	1.8	1.8	1.7	1.8	1.8	1.8	1.9	1.9		
Producer Price Index (nsa., d)	0.0	-0.5	-0.9	-1.1	-0.8	-0.5	-0.8	-0.8	-1.1	-1.6		
Durable Goods Orders (a)	1.9	-3.5	5.1	-1.7	-2.3	4.1	1.9	-2.9	-0.8	3.0		
Leading Economic Indicators (g)	0.2	-0.2	0.4	0.6	0.6	0.6	0.0	-0.1	-0.1	0.6		
Balance of Trade & Services (f)	-43.6	-38.5	-52.2	-43.4	-43.4	-46.3	-42.4	-48.8	-42.5	-43.9		
Federal Funds Rate (%)	0.11	0.11	0.11	0.12	0.12	0.13	0.13	0.14	0.14	0.12		
3-Mo. Treasury Bill Rate (%)	0.03	0.02	0.03	0.02	0.02	0.02	0.03	0.07	0.02	0.02		
10-Year Treasury Note Yield (%)	1.88	1.98	2.04	1.94	2.20	2.36	2.32	2.17	2.17	2.07		

2014 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	-1.2	1.2	1.5	0.5	0.5	0.3	0.2	0.6	-0.3	0.4	0.5	-0.9
Auto & Light Truck Sales (b)	15.29	15.51	16.46	16.21	16.64	16.74	16.45	17.22	16.42	16.46	17.02	16.80
Personal Income (a, current $)	0.5	0.6	0.6	0.2	0.3	0.4	0.3	0.4	0.2	0.4	0.5	0.3
Personal Consumption (a, current $)	-0.2	0.4	0.8	0.2	0.3	0.5	0.2	0.6	0.2	0.4	0.3	-0.1
Consumer Credit (e)	5.2	5.9	7.5	9.5	7.3	7.1	8.5	5.0	6.2	5.8	5.3	6.7
Consumer Sentiment (U. of Mich.)	81.2	81.6	80.0	84.1	81.9	82.5	81.8	82.5	84.6	86.9	88.8	93.6
Household Employment (c)	535	95	495	-72	144	379	154	50	156	653	71	111
Non-Farm Payroll Employment (c)	166	188	225	330	236	286	249	213	250	221	423	329
Unemployment Rate (%)	6.6	6.7	6.6	6.2	6.3	6.1	6.2	6.1	5.9	5.7	5.8	5.6
Average Hourly Earnings (All, cur. $)	24.22	24.30	24.34	24.34	24.4	24.46	24.47	24.55	24.55	24.59	24.68	24.62
Average Workweek (All, hrs.)	34.4	34.4	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.6	34.6	34.6
Industrial Production (d)	2.1	2.5	3.1	3.3	3.6	3.9	4.7	4.0	4.0	4.0	4.8	4.6
Capacity Utilization (%)	76.8	77.3	77.8	77.8	78.0	78.2	78.3	78.2	785	78.5	79.0	79.0
ISM Manufacturing Index (g)	51.8	54.3	54.4	55.3	55.6	55.7	56.4	58.1	56.1	57.9	57.6	55.1
ISM Non-Manufacturing Index (g)	54.3	52.5	53.7	55.3	56.1	56.3	57.9	58.6	58.1	56.9	58.8	56.5
Housing Starts (b)	0.888	0.951	0.963	1.039	0.986	0.927	1.095	0.966	1.026	1.079	1.007	1.080
Housing Permits (b)	1.002	1.030	1.061	1.074	1.017	1.033	1.041	1.040	1.053	1.120	1.079	1.077
New Home Sales (1-family, c)	446	417	410	410	457	408	403	454	459	472	449	495
Construction Expenditures (a)	-0.4	0.4	0.0	1.4	1.3	-1.6	0.3	0.1	0.6	1.4	-0.6	0.8
Consumer Price Index (sa, d)	1.6	1.1	1.5	2.0	2.1	2.1	2.0	1.7	1.7	1.7	1.3	0.8
CPI ex. Food and Energy (sa, d)	1.6	1.6	1.7	1.8	2.0	1.9	1.9	1.7	1.7	1.8	1.7	1.6
Producer Price Index (nsa., d)	1.3	1.2	1.6	1.8	2.1	1.8	1.9	1.9	1.6	1.5	1.3	0.9
Durable Goods Orders (a)	-1.4	2.6	3.7	0.9	-0.9	2.7	22.5	-18.3	-0.7	0.3	-2.2	-3.7
Leading Economic Indicators (g)	-0.2	0.6	1.0	0.3	0.6	0.6	1.0	0.1	0.6	0.6	0.3	0.5
Balance of Trade & Services (f)	-39.5	-42.8	-43.1	-44.3	-42.1	-42.4	-41.4	-41.3	-43.2	-42.8	-40.0	-45.6
Federal Funds Rate (%)	0.07	0.07	0.08	0.09	0.09	0.10	0.09	0.09	0.09	0.09	0.09	0.12
3-Mo. Treasury Bill Rate (%)	0.04	0.05	0.05	0.03	0.03	0.04	0.03	0.03	0.02	0.02	0.02	0.03
10-Year Treasury Note Yield (%)	2.86	2.71	2.72	2.71	2.56	2.60	2.54	2.42	2.53	2.30	2.33	2.21

(a) month-over-month % change; (b) millions of units, saar; (c) thousands of units, saar; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Special Questions:

1. Will the Federal Reserve's Open Market Committee vote to raise interest rates by 25 basis points at its December 15th-16th meeting?

(Percent of those responding)

Yes	No
100%	0%

2. By how many basis points will the FOMC raise interest rates in 2016?

	By how basis points will FOMC raise interest rates in 2016
Consensus	**82.06 basis points**
Top 10 Average	125.00 basis points
Bottom 10 Average	33.50 basis points

3. What will be the average monthly change in total nonfarm payroll employment during 2016?

	Average monthly change in total nonfarm payrolls during 2016
Consensus	**187.8 thousand**
Top 10 Average	231.2 thousand
Bottom 10 Average	152.9 thousand

4. What is your forecast of the y/y percent change in real residential investment in 2016?

	Y/Y percent change in real residential investment in 2016
Consensus	**8.3%**
Top 10 Average	12.3%
Bottom 10 Average	5.2%

5. The price index for personal consumption expenditures (PCE) and the PCE price index excluding food and energy prices, were up 0.2% and 1.3%, respectively, on a y/y basis in October. How much will they be up on a December-over-December basis in 2016?

2016 December-over-December, percent change:

	PCE price index	Core PCE price index
Consensus	**1.9%**	**1.9%**
Top 10 Average	2.4%	2.4%
Bottom 10 Average	1.4%	1.5%

6. The Institute of Supply Management's November index of acitivty in the manufacturing sector fell to 48.6. That marked its lowest level since June 2009 and signaled contraction in this sector of the economy. A strong U.S. dollar, weakness in the oil patch due to low prices, and cautious domestic capital spending has hit the manufacturing sector hard this year. Where will the ISM manufacturing index stand in December 2016?

	ISM Manufacturing index in December2016
Consensus	**52.5**
Top 10 Average	54.7
Bottom 10 Average	50.5

7. The per barrel price of West Texas Intermediate crude oil is currently trading around $41 per barrel. What will be the per barrel price at the end of 2016?

	Price of West Texas Intermediate Crude at end of 2016
Consensus	**$51.81 per barrel**
Top 10 Average	$58.92 per barrel
Bottom 10 Average	$44.82 per barrel

A Sampling of Views On The Economy Excerpted From Recent Reports Issued By Our Blue Chip Panel Members Or Others

Viewpoints:

Go For Launch

Although monthly data reports will continue to roll in over the next week in a half, the last of the major indicators to be released ahead of the Fed's much-anticipated December meeting are in. Chief among them was the November employment report. While Fed Chair Yellen in her testimony to Congress yesterday was careful to stress that the FOMC will not be putting much weight on any particular number, the report more than cleared the bar in showing that the labor market continues to improve. Payrolls rose by 211,000 in November, nearly spot on with its trend for the year. As expected, hiring was propelled by private services and construction, which more than offset cuts at mining and manufacturing firms.

Consistent with a tightening labor market, average hourly earnings rose 0.2 percent. Hourly earnings are up 2.3 percent over the past 12 months compared to a 2.1 percent increase this time last year. The unemployment rate held at 5.0 percent, as the labor force grew strongly and is within the FOMC's estimates of full employment.

Surveys from the Institute for Supply Management (ISM) continue to show the split between the industrial economy and the service sector. The ISM manufacturing index fell to 48.6 in November, the first contractionary reading since 2012. Deterioration was widespread across sub-indices. Historically, the Fed has typically cut rates, rather than raised them, when the ISM index was below 50. Yet, the services side of the economy continues to grow at a solid clip, generating a sizeable gulf between the manufacturing and non-manufacturing indices. The ISM non-manufacturing index fell 3.2 points in November from its second-highest reading in nearly a decade, but remains strong at 55.9. With the non-manufacturing index capturing 88 percent of the economy, the weighted average of the ISM indices sits comfortably in expansion territory at 55.0.

Other data released this week also shows activity outside of the factory sector remains robust. Auto sales for November registered a 18.1 million unit annualized pace for a second-straight month and are on track for their best sales year on record. Construction spending for October rose a better-than-expected 1.0 percent in October and is up 13.0 percent over the past year.

In a slew of Fed speak this week, FOMC members did not seem phased by the weaker-than-expected ISM figures and indicated a high bar for further delaying liftoff. FOMC Chair Yellen noted how risks from abroad have lessened since this summer and her confidence on inflation has been bolstered by continued improvement in the labor market. While a December rate hike is not guaranteed, Yellen's focus on the cumulative progress in the economy and the lagged effects of monetary policy suggest the committee is still on track to tighten on Dec. 16. The last major hurdle to clear before liftoff was today's employment report. With payrolls showing no deterioration in the trend of job growth, we believe the prospects for the Fed to lift rates before year-end look increasingly bright.

Economics Group, Wells Fargo, Charlotte, NC

Employment Report Removes Uncertainty About Fed

The solid jobs report for November removes a source of uncertainty for the Federal Reserve as the FOMC prepares for its upcoming meeting over December 15/16. We expect the FOMC to raise the fed funds rate to a range of 0.25 to 0.50 percent, representing the first increase since July 2006, when it was raised to 5.25 percent. The fed funds futures market currently shows an implied probability of 79.1 percent for a December 16 rate hike.

Financial market focus is shifting to 2016 and the expected path of later rate hikes. We can see in the most recent "dot plot" from the Federal Reserve, from September 17, that most of the FOMC expected at that time to see about 100 basis points of increase through 2016. The next dot plot, expected to be released on December 16, will be highly scrutinized for its forward looking implications. Right now it looks reasonable to expect a 25 basis point increase in the fed funds rate every other meeting in 2016, beginning in March 16. But Federal Reserve officials are taking pains to caution against a straight-line extrapolation of the fed funds rate through the year. Data dependence will remain the Fed's modus operandi.

Robert Dye, Comerica, Dallas, TX

The ECB Disappoints

Last week, we awarded President Mario Draghi of the European Central Bank (ECB) our economic "man-of-the-year" award. This week, Draghi and the ECB underperformed.

On Thursday, the ECB moved to accelerate the progress of eurozone inflation toward the central bank's target. The term of the ECB's quantitative easing program was extended by six months to March 2017, the deposit rate was lowered by 10 basis points to -0.30%, and the asset purchase program was broadened to include state and local government debt. The financial markets were clearly hoping for more. 2015 began with a "bazooka" from the ECB; the program announced at its January meeting was more substantial than expected. Draghi's recent remarks seemed to suggest that another significant salvo was coming. But this week's rate cut was modest, and the decision not to increase monthly bond buying was at odds with market expectations.

Draghi tried to ameliorate critics by stressing the ECB's decision to reinvest principal payments. But the average life of its bond holdings is close to 8 years. Therefore, the impact of reinvestment is likely to be visible only much later. After the announcement, the euro strengthened significantly, and European equity prices fell sharply. The ECB's quantitative easing program aims to devalue the euro and boost stock markets, so this outcome is counterproductive. The extent of the equity correction was a bit alarming; expectations of monetary policy action seem to be playing an outsized role in asset valuations across markets.

There was clearly some disagreement within the ECB's governing council over the proper course of policy. At present, eurozone growth shows a moderate upward trend; the ECB's staff forecast projects real economic activity to advance 1.5%, 1.7% and 1.9% during 2015-2017, respectively. Bank lending has been strengthening, and surveys reveal increasing levels of confidence over the outlook. If continued, these trends (along with some normalization in energy prices) should put upward pressure on eurozone inflation. This leads some to think that no further aid is called for.

But current inflation, at 0.1% over the past year, is far below the central bank's target. Core inflation, which excludes food and energy, is only 0.9%. And there are doubts about the growth outlook for Europe. Structural factors and fiscal austerity will dampen economic activity, despite some recent relaxation in spending targets. Exports account for about 45% of eurozone gross domestic product, and projections of modest global growth suggest that export-led advances are unlikely. The region remains vulnerable to the performance of its trading partners; risks are tilted to the downside.

In this post-crisis world, it can take a very long time for inflation to return to normal. Britain and the United States have expanded for most of the past seven years, but the price levels in both markets have fallen short of central bank expectations. In light of these precedents, it is far too early for the ECB to claim victory.

Carl Tannenbaum and Asha Bangalore, Northern Trust, Chicago, IL

Calendar Of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
November 7 Consumer Credit (Oct)	**8** NFIB Survey (Nov) JOLTS (Oct)	**9** Wholesale Trade (Oct) EIA Crude Oil Stocks Mortgage Applications	**10** Imports Prices (Nov) Quarterly Services Survey (Q3) Federal Budget (Nov) Weekly Jobless Claims Weekly Money Supply	**11** Consumer Sentiment (Dec, Preliminary, University of Michigan) Retail Sales (Nov) Producer Price Index (Nov) Business Inventories (Oct)
14	**15** **FOMC Meeting** Consumer Price Index (Nov) Empire State Survey (Dec) NABH Survey (Dec) TIC Data (Oct)	**16** **FOMC Meeting** **Statement and Projections** **2:00 p.m.** **Press conference** **2:30 p.m.** Industrial Production (Nov) Housing Starts (Nov) Manufacturing PMI (Dec, Flash) EIA Crude Oil Stocks	**17** Philadelphia Fed Survey (Dec) Current Account (Q3) Weekly Jobless Claims Weekly Money Supply	**18** Markit Services PMI (Dec, Flash) Kansas City Fed Survey (Dec)
21	**22** Real GDP (Q3, Third estimate) Richmond Fed Survey (Dec) Existing Home Sales (Nov) FHFA Home Price Index (Oct)	**23** Durable Goods (Nov) New Home Sales (Nov) Consumer Sentiment (Dec, Final, University of Michigan) Consumer Sentiment (EIA Crude Oil Stocks Mortgage Applications	**24** Weekly Jobless Claims Weekly Money Supply	**25** **Christmas Day** **Bond and Stock Markets Closed**
28 Dallas Fed Survey (Dec)	**29** S&P/Case-Shiller Home Price Index (Oct) Consumer Confidence (Dec, Conference Board)	**30** Pending Home Sales (Nov) EIA Crude Oil Stocks Mortgage Applications	**31** Chicago PMI (Dec) Weekly Jobless Claims Weekly Money Supply	**January 1** **New Year's Day** **Bond and Stock Markets Closed**
4 ISM Manufacturing (Dec) Markit Manufacturing PMI (Dec, Final) Construction Spending (Nov)	**5** Vehicle Sales (Dec)	**6** ADP Employment (Dec) International Trade (Nov) ISM Non-Manufacturing (Dec) Markit Services PMI (Dec, Final) Factory Orders (Nov) **FOMC Minutes** EIA Crude Oil Stocks Mortgage Applications	**7** Chain Store Sales (Dec) Challenger Job Cut Report Weekly Jobless Claims Weekly Money Supply	**8** Employment Report (Dec) Wholesale Trade (Nov) Consumer Credit (Nov)
11	**12** JOLTS (Nov) NFIB Survey (Dec)	**13** Beige Book Federal Budget Mortgage Applications EIA Crude Oil Stocks	**14** Weekly Jobless Claims Weekly Money Supply	**15** Industrial Production (Dec) Retail Sales (Dec) Empire State Survey (Jan) Producer Price Index (Dec) Business Inventories (Nov) Consumer Sentiment (Jan, Preliminary, University of Michigan)

EXPLANATORY NOTES

For 40 years, ***Blue Chip Economic Indicators'***® monthly survey of leading business economists has provided private and public sector decision-makers timely forecasts of U.S. economic growth, inflation and a host of other critical indicators of business activity. The newsletter utilizes a standardized format that provides a fast read on the prevailing economic outlook. The survey is conducted over two days, typically beginning on the first or second business day of each month. Forecasts of U.S. economic activity are collected from more than 50 leading business economists each month. The newsletter is generally finished on the third day following completion of the survey and delivered to subscribers via e-mail or first class mail.

The hallmark of ***Blue Chip Economic Indicator***® is its *consensus forecasts*. Numerous studies have shown that by averaging the opinions of many experts, the resulting consensus forecasts tend to be more accurate over time than those of any single forecaster.

Annual Forecasts On pages 2 and 3 of the newsletter are individual and consensus forecasts of U.S. economic performance for this year and next. The names of the institutions that contribute forecasts to these pages are listed on the left of the page. They are ranked from top to bottom based on how fast they expect the U.S. economy to expand in the current year. Some of these institutions have one or more asterisks (*) after their names, denoting how many times they have won the annual *Lawrence R. Klein Award for Blue Chip Forecast Accuracy*.

Across the top of pages 2 and 3 is a list of the variables for which the individual cooperators have provided forecasts. Definitions and organizations that issue estimates for these variables are found at the bottom of page 3. For columns 1-9, the forecasts are for the year-over-year percent change in each variable. Columns 10-12 represent average percentage levels of the year in question. Column 15 is an inflation-adjusted dollar level, measured in billions of chained 2009 dollars. High and low forecasts from the panel members for each variable are denoted with an "H" or "L".

Immediately below the forecasts of the individual contributors are this month's consensus forecasts. The consensus is derived by averaging our panel members' forecasts for each variable. Below the consensus forecasts are averages of this month's ten highest and ten lowest forecasts for each variable. Below them are last month's consensus forecasts. To put the forecasts in context, we include four years of historical data for each variable at the bottom of page 2. Please note that these figures can change due to government revisions of previously released estimates. Below the historical data are the number of forecasts changed from a month ago for each variable, the median forecast for each variable and a diffusion index. The diffusion index serves as a leading indicator of future changes in the consensus forecast. A reading above 50% hints of future increases in the consensus; a reading below 50% hints of future declines. The diffusion index is calculated by adding to the number of forecasters who raised their forecasts for a particular variable this month, half the number of those who left their forecasts unchanged, then dividing the sum by the total number of those contributing forecasts.

Historical Annual Consensus Forecasts Page 4 contains the forecasts from previous issues for the current and subsequent year so that subscribers can see how the outlook has changed over time. Each issue also includes graphs and analysis focusing on noteworthy changes and trends in the consensus outlook.

Quarterly Forecasts Page 5 contains quarterly historical data and consensus forecasts of the U.S. economy's performance. For columns 1-7, the forecasts are for the quarter-over-quarter, seasonally-adjusted, annualized percent change in each variable. Columns 8-10 represent average percentage levels for the quarter in question. Columns 11 and 12 represent seasonally-adjusted, annualized levels for the quarter, measured in billions of inflation-adjusted dollars. As is the case on pages 2-3, the consensus quarterly forecasts on the top half of page 5 are simple averages of our contributors' forecasts. The high-10 and low-10 forecasts are averages of the 10 highest and 10 lowest forecasts for each variable. At the bottom of page 5 are additional quarterly consensus forecasts for Real GDP, GDP Price Index, Industrial Production and Consumer Price Index. These figures are derived by taking the annualized quarterly consensus forecasts found on the top of page 5 and computing a quarterly dollar value for Real GDP, and average quarterly index levels for the GDP Price Index, Industrial Production and the Consumer Price Index. We then compute a year-over-year percent change between the relevant quarter and the corresponding quarter of the previous year.

International Forecasts Pages 6-7 contain historical data and consensus forecasts of five key economic variables for 15 of the U.S.'s largest trading partners. A list of the institutions contributing forecasts to these pages can be found at the bottom of page 7. Columns 1 and 2 are forecasts of the year-over-year percent change in inflation-adjusted economic growth and consumer price inflation for this year and next. Column 3 is each nation's estimated current account surplus or deficit, reported in billions of current U.S. dollars. Column 4 is the estimated value of each nation's currency versus the U.S. dollar at the end of this year and next. Column 5 is the estimated level of interest rates on 3-month interest rates in each nation at the end of this year and next. Immediately below this month's consensus and the highest and lowest estimates for each variable are last month's forecasts and a limited amount of historical data. The historical data may change from month-to-month due to government revisions.

Special Questions On page 14, we report on panel members' answers to our special questions. Individuals' responses to the special questions are never displayed, only consensus, top-10 and bottom-10 results. *In March and October, we publish our twice-a-year, long-range survey results*. In addition to our usual forecasts for this year and next, the long-range survey results provide subscribers with consensus forecasts of all the variables found on pages 2 and 3 for the each of the following five years, plus an average for the five-year period after that.

Blue Chip Econometric Detail® With the March, June, September and December issues, subscribers also receive a four-page quarterly supplement entitled *Blue Chip Econometric Detail*®. The supplement contains forecasts of an expanded list of economic and financial variables that are derived from the consensus forecasts found in *Blue Chip Economic Indicators*®. Macroeconomic Advisers, LLC of St. Louis, Missouri produces this forecast detail based on a simulation of its econometric model of the U.S. economy.

*Should you have questions about the contents, or methods used to produce **Blue Chip Economic Indicators**® please contact Randell Moore at randy.moore@wolterskluwer.com or call him at (816) 931-0131.*

Attachment 3.7

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 4.2

MOODY'S
INVESTORS SERVICE

REQUEST FOR COMMENT

Proposed Refinements to the Regulated Utilities Rating Methodology and our Evolving View of US Utility Regulation

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Introduction

We are seeking market feedback on a number of refinements that we are proposing to make in an update to our Regulated Electric and Gas Utilities Rating Methodology, which was last published in August 2009. The proposed updated rating methodology will continue to have a particular focus on regulatory risk and financial performance. The grid that is part of the proposed updated rating methodology is comprised of the same four factors as the existing grid: regulatory framework, ability to recover costs and earn returns, diversification, and financial strength. However, it will provide additional granularity on individual factor scores, add new sub-factors, and increase the relative weighting of the financial metrics when determining the grid-indicated rating. We do not expect that implementation of the proposed refinements will lead to any changes in current ratings.

On a separate issue, we are also seeking market commentary on our evolving view of the credit supportiveness of the US utility regulatory framework. Based on our observations of trends and events, we propose to adopt a generally more favorable view of the relative credit supportiveness of the US utility regulatory environment. Our updated view considers improving regulatory trends that include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators. While US state regulatory environments have been characterized by a process that is more openly adversarial than some other global jurisdictions, there have been very few instances where eventual regulatory outcomes deviated enough from the established regulatory framework to severely undercut utility creditworthiness. In the few instances where inconsistent regulatory decisions have led to serious credit stress, courts have proved to be a reliable secondary support for utility credit worthiness through rulings that mandate that regulatory decisions must follow the established regulatory framework.

Our revised view that the regulatory environment and timely recovery of costs is in most cases more reliable than we previously believed is expected to lead to a one notch upgrade of most regulated utilities in the US, with some exceptions. This evolving view is independent of the proposed changes in the methodology that are highlighted in the Summary section that follows, and would have taken place even if the 2009 methodology were to remain in place without modification.

Although the change of our US regulatory view does not by itself require the publication of a Request for Comment, based on an unusual confluence of factors in this instance, including the proximity in time of this change in view to an expected update in the methodology (even though the two are unrelated), the heavy weighting that regulatory factors have in our ratings as reflected in both the existing and proposed methodologies, the large number of US utilities that are potentially affected and the magnitude of debt outstanding in the sector, we think it is important to clearly communicate our developing views in this document and to solicit comments from market participants who may have interest.

We invite market participants to provide comments on this proposal and to make other suggestions for consideration by sending comments by October 23, 2013. Comments should be sent to RFC@moodys.com using the Request for Comment Form (the "RFC Response Form") available on the Request for Comment topic page on www.moodys.com. If your comments pertain to the proposed refinements to the rating methodology, please reference "Part I: Regulated Utility Methodology" in the topic line of your response. If your comments pertain to our evolving view of US utility regulation, please reference "Part II: US Utility Regulation" in the topic line of your response. The RFC response period for each of these topics will be open for at least 30 days from the date of publication of this Request for Comment.

Summary

PART I: Proposed Update of the Regulated Electric and Gas Utilities Methodology

Changes to the Grid: Additional sub-factors and changes to factor weighting

» We propose to add sub-factors under Factor 1- Regulatory Framework and Factor 2- Ability to Recover Costs and Earn Returns, to provide more granularity and to better distinguish among regulated utilities. The sub-factors include Sub-factor (1a) – Legislative and Judicial Underpinnings to Regulatory Framework (12.5% weighting) , Sub-factor (1b) – Consistency and Predictability of Regulation (12.5%), Sub-factor (2a) – Timeliness of Recovery of Operating and Capital Costs (12.5%), and Sub-factor (2b) - Sufficiency of Rates and Returns (12.5%). A preliminary draft of the grid for the updated rating methodology is included in Appendix A and shows the new sub-factors.

» We propose to refine Factor 3 – Diversification to focus more on regulatory diversity and the strength of the service territory economy as the key considerations in the scoring of the Market Position sub-factor. We also propose to change the Generation and Fuel Diversity sub-factor by replacing the emphasis on carbon fuels with the broader concepts of "challenged" and "threatened" sources of generation, as detailed in Appendix B.

» The range of possible scores under each factor, previously Aaa to B, has been expanded to include the Caa rating category. The purpose is to provide greater transparency in the thinking behind our ratings for issuers at the lower end of the spectrum.

» The Liquidity sub-factor, currently weighted at 10% in the grid, will be removed from the methodology grid entirely and instead analyzed as a key rating consideration outside the grid. However, there will be no diminution in our emphasis on liquidity as a key rating driver, since it always an important credit consideration and can become the primary rating consideration if it is mismanaged or becomes problematic for a utility.

- » The weighting in the grid for the four financial ratios that comprise Factor 4 – Financial Strength will increase to 40% from 30%, although the specific ratios will remain the same. Additional weighting and importance will be given to the two cash flow to debt ratios: CFO pre-WC/Debt (to 15% from 7.5%) and CFO pre-WC less Dividends/Debt (to 10% from 7.5%), with the other two ratios continuing to be weighted at 7.5%. The above-mentioned expansion of the scoring range will cause some changes in grid parameters outlined for each rating category, primarily at the lower end of the grid.
- » The scoring grids, including the ranges for financial ratios, are primarily oriented toward vertically integrated utilities. We are contemplating lowering the financial ratio threshold ranges by approximately one category for certain utilities viewed as having lower business risk, for instance many US natural gas local distribution companies (LDC's) and certain US electric transmission and distribution companies (T&D's, which lack generation but generally retain some procurement responsibilities for customers). The purpose would be to better align the grid-scoring to our view, reflected in current ratings, that utilities at the same rating category level with an inherent lower business risk can have somewhat lower financial metrics. Alternately, business risk may be addressed in a different manner; for instance, by incorporating it more broadly into the qualitative factor scoring grids. Typically, lower risk utilities would be those having no electric generation assets, very strong insulation from commodity risks, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural disasters.

Additional summary comments about the updated rating methodology:

- » As is our current practice, actual ratings of utility holding companies may be lowered by a notch or more because of structural subordination, and we are contemplating the potential of including this notching into our grid-indicated ratings to provide greater transparency. Our approach has and will consider the relative percentage of debt at the holding company versus debt at the operating subsidiaries, the diversity of holding company cash flows, the composition and materiality of non-utility businesses, and other considerations.
- » We also propose to maintain our existing approach to notching between classes of debt. In most regions, we rate the senior secured debt of a utility one notch above its senior unsecured debt. However, US utility first mortgage bonds are typically rated two notches higher than the senior unsecured debt of the same issuer, given their first priority lien on critical infrastructure assets and the very high historical recovery rates for this class of debt in default situations.

The grid in the proposed methodology contains the same four factors as the existing rating methodology with the same weighting for each factor, but there are changes in the sub-factors and their weighting. We propose to assign equal weighting to four new sub-factors related to the regulatory framework and ability to recover costs and earn returns because we believe these sub-factors typically work together in approximately equal proportion as indicators of regulatory risk. These four sub-factors would still total 50% of the overall grid score, reflecting our view that the regulatory environment is the most important determinant of credit quality in the sector and generally comprises about half of the elements that are most pertinent for credit quality.

The grid in the proposed rating methodology would use the same four financial ratios but with some changes in weighting. The weighting of the two existing measures of cash flow generation relative to debt is to be increased because we believe these financial ratios are the strongest direct indicators of current capacity to service debt. The proposed 15% weight for CFO Pre-WC/Debt reflects our view that this is the single most predictive financial measure, followed in importance by CFO Pre-WC -

Dividends/Debt with a proposed 10% grid weighting. The additional weighting of these ratios is to be balanced by elimination of the separate liquidity sub-factor that has a 10% weighting in the existing grid. We propose to remove liquidity from the grid and consider it as a qualitative assessment outside the grid because its credit importance varies greatly over time and by issuer and accordingly is not well represented by a fixed grid weight. The weighting of the grid indicators for diversification are unchanged, but the proposed descriptive criteria have been refined to place greater emphasis on the economic and regulatory diversity of each utility's service area rather than the diversity of operations, because we think this emphasis better distinguishes credit risk.

As noted in the Summary above, we do not expect that implementation of the proposed refinements in the updated rating methodology will by themselves lead to any changes in current ratings.

PART II: Revised View of US Utility Regulation

» Our view of the credit supportiveness of regulatory jurisdictions around the globe is constantly evolving along with events. In most cases we would expect to simply update our view and to simultaneously make any rating changes that result. However, considering the large number of rated US utilities and the volume of their rated debt, combined with the magnitude of change in our view, we are soliciting comments on our rationale for a more favorable view of the US regulatory environment. We believe that many US regulatory jurisdictions have become more credit supportive of utilities over time and that the assessment of the regulatory environment in the US that has been incorporated in ratings may now be overly conservative.

» While we had previously viewed individual state regulatory risks for US utilities as generally being higher than utilities in most other developed countries (where regulation usually occurs at the national level), we have observed an overall decrease in regulatory risk in the US. While state regulatory jurisdictions seem to be more prone to highly visible disputes and parochial political intervention than national regulatory frameworks, which has sometimes raised concerns about regulatory consistency, we now believe that the more openly adversarial process in the US does not lead to materially less reliable regulatory outcomes for credit quality.

» There have been a number of favorable regulatory changes in recent years. For example, the increasing prevalence of riders, trackers, and other automatic cost recovery provisions in the US has reduced the amount of time between when a utility incurs and recovers costs, or "regulatory lag." These changes have happened incrementally - jurisdiction by jurisdiction or even issuer by issuer. We now believe that these changes, in aggregate, represent a significant improvement in the timeliness of cost recovery.

» We believe the majority of US utilities enjoy relatively fair and open relationships with their regulators, and that most regulators strive to maintain reliable, financially viable utilities in their states, while also balancing the needs of the state's commercial, industrial, and residential utility customers.

» There have been selected instances of regulatory and political pressure leading to financial distress for utilities in some US states, such as California, Illinois, and Maryland. However, it is noteworthy that state regulators have stopped short of triggering defaults after the experience in California where subsequent court rulings reversed regulatory actions that contributed to defaults by the two largest utilities in the state. We think regulatory decisions consider eventual judicial outcomes, and we propose to give more emphasis to the relatively consistent US judicial framework as a factor that discourages highly inconsistent regulatory actions that would have a severe credit impact.

» Part of the evolution to our thinking is to give greater emphasis to the judicial framework into our analysis. A material number of litigated regulatory matters over the past decade could be viewed as an indication of a less supportive framework. However, the resultant body of case law has provided greater clarity into the rules of engagement for both utilities and regulators, which we view as providing a generally greater level of stability.

» We continue to believe US utilities may have more incentives to enter bankruptcy proceedings relative to similarly rated corporate issuers, due to their good track record of being able to reorganize and obtain rate relief while under the protection of federal bankruptcy courts. Nonetheless, utilities have experienced default rates that are lower than non-financial corporate issuers and much lower losses given default. This has been well documented in Moody's default and recovery studies on regulated utility debt.

» A comparison of key financial ratios used under the Regulated Electric and Gas Utilities Rating Methodology in rating utilities across several developed international jurisdictions with credit supportive regulatory frameworks (including Canada and Japan) shows that US regulated utilities in recent years have exhibited stronger financial ratios relative to similarly rated regulated international utility peers.

» We acknowledge that every regulatory framework will need to accommodate new realities and challenges that arise to confront the industry. Current examples of such challenges in the US include new nuclear construction, public policy initiatives on renewable energy, and the rise of distributed generation. However, our current view is that regulators and utilities will be able to reach reasonable agreements regarding these issues.

» As previously noted, our view of regulatory environments is constantly evolving and we normally make changes in our view and resulting rating changes without publishing a Request for Comment. We have seen a decline in the credit supportiveness of some regulatory environments that had been previously viewed as highly credit supportive. For example, we adopted a more conservative assessment for the regulatory environment and timely cost recovery for all of the Japanese utilities following the Fukushima disaster in 2011. This led to downgrades of their ratings and was reflected in lower scoring in our assessment of the regulatory and cost recovery factors in the grid.

For these reasons, we believe a more positive view of US utility regulation is warranted. This is expected to lead to a one notch upgrade of the ratings of most regulated utility credits in the US, with some exceptions. An improved view of US state regulatory frameworks is also likely to lead to higher scoring for many US utilities under the grid factors for utility regulatory frameworks and/or cost recovery provisions.

In most cases, we would expect all of the debt classes of a utility's capital structure to be upgraded by the same number of notches, although there could be some limited exceptions to this general rule. Most utility holding companies will be upgraded by the same number of notches to the extent that the upgraded regulated utility subsidiaries represent the holding company's predominant business and there are no extenuating circumstances, such as a large amount of holding company debt, substantial unregulated or other higher risk businesses, or other factors that may increase credit risk at the holding company.

While we anticipate that most US regulated utilities will be upgraded, there are issuer specific circumstances that may preclude an upgrade. These may include but are not limited to the following:

» Utilities that are part of corporate families that have significant unregulated or other higher risk operations as part of their overall business mix;

» Other corporate family considerations, such as a highly levered holding company, a complex corporate structure, or exposure to contagion risk due to the existence of lower rated affiliates;

» Utilities that are engaged in substantial construction programs for new generation plants (especially those with long lead-times or with technology that is less tested) or are in the midst of other major capital projects;

» Utilities that face material cost recovery risks or challenges related to significant capital investments;

» Utilities subject to concentration and/or event risk that are exposed to potentially sudden and unexpected changes in credit profile; and

» Utilities that are under downward credit pressure, particularly where this is reflected in a review for downgrade or a negative rating outlook.

Part I: Detailed Explanation of Proposed Refinements to Regulated Utilities Rating Methodology

This report includes a detailed rating grid that provides a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in this sector. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions, but actual importance may vary substantially. In addition, the illustrative mapping examples typically included in the rating methodology and some of our other published research use historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company in most cases.

The rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to avoid greater complexity that would result in grid-indicated ratings that map more closely to actual ratings in favor of a simple and more transparent presentation.

Addition of Sub-factors under Factor 1 - Regulatory Framework and Factor 2 - Ability to Recover Costs and Earn Returns

We have added sub-factors under Factor 1 – Regulatory Framework and Factor 2 – Ability to Recover Costs and Earn Returns, to provide more granularity and to better distinguish among regulated utilities. With Factors 1 and 2 each weighted at a relatively high 25% of the overall grid outcome in the current methodology, incremental changes in a utility's regulation or cost recovery provisions are not easily indicated. Breaking down these two broad factors into two sub-factors will allow us to better reflect and communicate sometimes subtle differences in regulatory and/or cost recovery provisions among utilities. The new sub-factors include Sub-factor (1a) – Legislative and Judicial Underpinnings to Regulatory Framework (12.5% weighting) , Sub-factor (1b) – Consistency and Predictability of Regulation (12.5%), Sub-factor (2a) – Timeliness of Recovery of Operating and Capital Costs (12.5%), and Sub-factor (2b) - Sufficiency of Rates and Returns (12.5%). A draft of each of these new methodology sub-factors is included in Appendix A.

Factor 1 – Regulatory Framework

Sub-factor 1a – Legislative and Judicial Underpinnings to Regulatory Framework (12.5% weighting)

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is, as well as the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Finally, we consider how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it. The inclusion of this sub-factor also represents a more explicit acknowledgement that the judicial system can be a major determinant of the regulatory framework.

Sub-factor 1b – Consistency and Predictability of Regulation (12.5%)

For this sub-factor, we consider the track record of regulatory decisions, in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility. In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is encouraged by a relatively open regulatory process, and statements that are more clearly indicative of future actions and trends in decision-making.

Factor 2 – Ability to Recover Costs and Earn Returns

Sub-factor 2a – Timeliness of Recovery of Operating and Capital Costs (12.5%)

The criteria we consider in our assessments for this sub-factor include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to measure, or at least estimate, the lag between the time that a utility incurs major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

Sub-factor 2b - Sufficiency of Rates and Returns (12.5%)

The criteria we consider in our assessments for this sub-factor include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning its allowed returns. We examine rate case outcomes and compare them to the rate request submitted by the utility, to prior rate cases for the same utility and to recent rate case outcomes for a peer group of comparable utilities. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also the reasons given by the regulator, to determine the likelihood that such disallowances will be repeated in the future.

Refinement and Broadening of Factor 3 - Diversification

Sub-factor 3a – Market Position (5% or 10%)

The market position sub-factor will be refined to focus primarily on the economic diversity of the utility's service territory and the diversity of its regulatory regime. We will also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area. Economic diversity is typically a function of the size and breadth of the territory and the businesses that drive its GDP and employment. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. For vertically integrated utilities that have a meaningful amount of generation, this sub-factor will continue to have a weighting of 5%. For electric and transmission utilities without meaningful generation and for natural gas local distribution companies, this sub-factor will continue to have a weighting of 10%.

Sub-factor 3b – Generation and Fuel Diversity (0% or 5%)

We have changed this sub-factor by replacing the emphasis on exposure solely to carbon fuels in the current methodology with the broader concepts of exposure to "challenged" or "threatened" sources of generation. The sub-factor will continue to consider the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer to economically shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to the aforementioned "challenged" or "threatened" sources. For issuers with a meaningful amount of generation, this factor will continue to have a weighting of 5% and for those with no generation, 0%. The definition of "challenged" and "threatened" sources of generation is included in Appendix B.

Liquidity Analyzed as Key Rating Consideration Outside of Methodology Grid

The Liquidity sub-factor, weighted at 10% in the current grid, will be removed from the grid and will be analyzed as a key rating consideration outside the grid. However, there will be no diminution in our emphasis on liquidity as a key rating driver. Liquidity is always an important credit consideration and can become the primary rating consideration if it is mismanaged or becomes problematic for a utility. Liquidity can be of particular importance in an industry in which companies frequently generate negative free cash flow due to high capital expenditures and significant dividend payments.

Our fundamental analysis of a utility's liquidity will remain unchanged in the updated rating methodology. Using our projections of the financial performance of an issuer, we evaluate how its projected sources of cash (cash from operations, cash on hand, and existing multi-year credit facilities) compare to its projected uses (including all planned capital expenditures, dividends, maturities of short and long-term debt, and our projection of potential liquidity calls on financial hedges). Our assessment of liquidity assumes no access to capital markets, no incremental credit facilities, no renewal of existing credit facilities, no decrease in capital expenditures from the plan, and no reduction in dividends.

Methodology Grid Expanded to Include "Caa" Category

The range of possible scores under each factor in the grid, currently ranging from Aaa to B, will be expanded to include a "Caa" category. The purpose of this change is to provide greater transparency in our scoring of the grid for ratings at the lower end of the spectrum. While regulated utilities predominantly comprise an investment grade sector, with most issuers unlikely to be assigned grid scores of Caa, regulated utilities experiencing severe financial stress and some utilities in certain emerging markets are more likely to be scored at the lower end of the grid. As is demonstrated in the revised methodology sub-factor grids included in Appendix A, the criteria for Caa scoring is categorized as utilities with very unsupportive regulatory frameworks, poor or highly uncertain cost recovery provisions, little to no diversification, and extremely weak financial metrics. The inclusion of the Caa level in the grid will provide greater granularity that better enables distinctions among utilities at the lower end of the grid.

Weighting of Four Key Financial Ratios Increased to 40% from 30%

The overall weighting of the four key financial ratios included in Factor 4 – Financial Strength will increase to 40% from 30%, although the ratios themselves will remain the same. The ratios will continue to include Moody's standard adjustments and, in certain instances, analyst-determined adjustments specific to the issuer.

In the revised grid that is part of the proposed updated methodology, additional weighting will be given to the two cash flow to debt ratios to better reflect their importance in our financial analysis and in our credit rating discussions. For the most part, the financial parameters outlined for each scoring category will remain the same, except at the lower end of the grid, where slight adjustments to the parameters have been made to accommodate the aforementioned expansion of the grid to include a "Caa" scoring category.

The four financial ratios and their revised weightings where applicable are listed below:

» Cash from operations before changes in working capital (CFO Pre-W/C) + interest / interest – 7.5%*

» CFO Pre-W/C / debt – 15% (up from 7.5%)*

» CFO Pre-W/C - dividends / debt – 10% (up from 7.5%)*

» Debt / capitalization or debt / regulated asset value (RAV) – 7.5%*

*It is anticipated that the illustrative examples in the updated rating methodology document will use three year historical averages for financial ratios. However, the factors in the grid can be assessed using various time periods and rating committees may find it analytically useful to examine both historic and expected future performance for various periods of time.

Financial Ratio Threshold Ranges May Be Lowered Based on Business Risk

In our view, the different types of utility entities covered under this methodology have different levels of business risk. Vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays. Other types of utilities may have lower business risk, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural disasters For instance, we tend to view many US natural gas local distribution companies (LDC's) and certain US electric transmission and distribution companies (T&D's, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers.

The scoring grids, including the financial ratio ranges in the Factor 4 grid shown in Appendix A, are primarily oriented toward vertically integrated utilities. We are contemplating lowering the financial ratio threshold ranges for utilities with lower business risk, including lower risk T&D's and LDC's in the US, by approximately one category. As an example, the threshold for a Baa category scoring in interest coverage for a vertically integrated utility (3.0x - 4.5x) would, for a utility with lower business risk, be the range for an A category scoring. The purpose would be to better align the grid-scoring to our view, reflected in current ratings, that at the same rating category, utilities with lower business risk can have somewhat lower financial metrics. Alternately, business risk may be addressed in a different manner, for instance by incorporating it more broadly into the qualitative factor scoring grids. In cases of T&D's that we do not view as having materially lower risk than their vertically integrated peers, for instance due to increased risks from substantial storm exposure, a regulatory framework that exposes T&D's to energy supply risk, large capital expenditures for required maintenance or upgrades, or increased regulatory scrutiny due to poor reliability or other issues, we may instead use the same Factor 4 grid ranges as those for integrated utilities. The same may be true for LDC's that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

Notching of Utility Holding Company Ratings Due to Structural Subordination May Be Included as a Grid Adjustment

Many utility company structures consist of a holding company that owns one or more operating subsidiaries. Under our current practices, ratings of utility holding companies are in many cases likely to be below those of operating companies due to structural subordination, since creditors of an operating subsidiary typically have a more direct claim on the cash flows and assets of these subsidiaries than do creditors of a holding company. When deciding whether or not to rate a holding company lower than it would be rated if it were an operating company, our considerations may include the relative percentage of debt at the holding company versus debt at the utility operating subsidiaries, operating company debt as a percentage of consolidated assets, the regulatory or effective limitations on movement of cash among the companies in the corporate family, the diversity of holding company cash flows, the composition and materiality of non-utility businesses, as well as other considerations. While structural subordination may exist in any industry sector, it is a particularly prevalent credit issue in the utility sector, because incurrence of debt at both operating and holding companies is more widespread. We are contemplating the potential of including our notching practices into our grid-indicated ratings to provide greater visibility into the impact of this risk factor on ratings.

US Utility First Mortgage Bond Ratings are Typically Two Notches Above the Senior Unsecured Rating

In most regions, the typical rating relationship between different debt classes of regulated utilities is the same as for other investment grade non-financial corporate sectors, with senior secured debt rated one notch higher than the same issuer's senior unsecured rating. For the relatively small number of speculative grade utility issuers in certain regions, we apply our loss given default ratings methodology. However, our existing practice is to generally apply a two notch uplift to the first mortgage bond ratings of regulated electric and gas utilities in the US, and the updated rating methodology will not affect such rating relationships.

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

We may not always rate US first mortgage bonds two notches higher than the senior unsecured rating, for instance if the pledged property is not viewed by Moody's as being critical infrastructure, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

PART II: Additional Details on Our Evolving View of US Utility Regulation

Note that the following discussion of our evolving view of US utility regulation does not represent a change in our rating methodology and does not require that a Request for Comment be published. However, given the large number of US utilities affected and the magnitude of debt outstanding in the US utility sector, in the interest of clarity, we thought it was important to share our views broadly by including them in this document and soliciting comments from those who may have interest. This change in our view of US utility regulation is independent of proposed revisions to the rating methodology and would have the same rating impact under the existing rating methodology and the proposed update to the rating methodology.

The Overall US Regulatory Environment Has Become More Credit Supportive

In recent years we believe that some regulatory jurisdictions have become more credit supportive of regulated utilities, most notably in the US. While we had previously viewed the regulatory risk of US utilities, typically regulated at the state level, as being higher than utilities in most other developed countries where regulation occurs at the national level, we are contemplating a significant revision of our view. We see improved levels of regulatory support across the US, which includes the increased use of single issue riders and trackers, timely rate case outcomes or rate settlements, and a collaborative approach toward infrastructure investment and refurbishment.

The increased prevalence of riders, trackers, and other automatic cost recovery mechanisms in the US has materially reduced the amount of time between when a utility incurs and recovers costs, otherwise known as "regulatory lag." These changes have occurred incrementally – jurisdiction by jurisdiction or even issuer by issuer. We now believe that these changes, in aggregate, represent a significant improvement in cost recovery.

EXHIBIT 1

Average Regulatory Lag

Source: SNL Financial/Edison Electric Institute

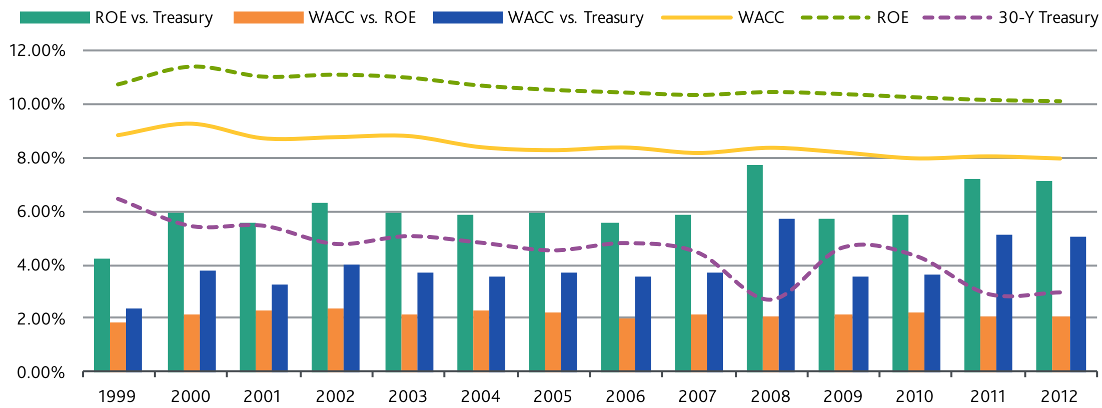
We also believe that the majority of US utilities enjoy relatively fair and open relationships with their regulators, and that most regulators strive to maintain reliable, financially viable utilities in their states, while also balancing the needs of the state's commercial, industrial, and residential utility customers. We see a high degree of regulatory support continuing for much of the sector, as sustained low natural gas prices help to foster a collaborative relationship between utilities, regulators, and customers. Low fuel prices, which are the industry's most significant expense, provide increased economic flexibility for regulators to more easily approve and for utilities to implement base rate increases and other cost recovery mechanisms.

While state regulation has the potential to reflect more intensive disputes and parochial interests, a regional business model is particularly well suited to effective constituency outreach efforts. Utilities are important contributors to the well-being of their local communities, and are typically one of the largest publically traded companies and largest employers in their areas, as well as a major source of property taxes for state and local governments.

Although allowed ROE's are in decline, we observe that they remain at favorable levels compared to the historical average 30 year treasury rates and that ROE's are in line with historical levels of a utility's weighted average cost of capital. However, as treasury rates have begun to increase in 2013, we note that US utility ROE levels may not increase commensurately or on as timely a basis, potentially pressuring industry profitability going forward.

EXHIBIT 2

US Regulated Utility Returns vs. Costs



Source: SNL Financial/Bloomberg

Over the intermediate term, we see utilities experiencing a decline in general rate case filings, whether due to prescriptive and forward looking rate plans that have been approved by their regulators, or due to a utility's willingness to postpone rate cases and focus on managing costs in an environment of low inflation and low fuel costs. This has been an evolution from historical experience, where many utilities filed more frequent rate cases requesting smaller rate increases in order to reduce regulatory lag and avert potential customer resistance. We view this change as a result of several factors, including the aforementioned growing use of tracking mechanisms, as well as increased willingness of regulators to be more forward looking in their rate setting than historically. We have also found that differentiating among rate case outcomes among individual states has become increasingly difficult, as most utilities have in recent years experienced fair and balanced rate case outcomes, with many agreeing to rate settlements or other negotiated outcomes.

Part of the evolution of our thinking has been an increased emphasis on the relevant judicial framework in our assessment of a utility's regulatory framework. The material number of litigated regulatory matters in the US could be viewed as indication of a less supportive framework. However, it may simply reflect a greater tendency for parties to pursue court remedies, and the resultant body of relatively consistent case law has provided greater clarity into the rules of engagement for utilities and their regulators as well as greater visibility into the legal outcomes that would result from a regulatory dispute, thereby reducing the likelihood that a critical regulatory issue between a utility and regulatory commission would depart so far from expectations as to trigger a default.

We are contemplating a more favorable view of US regulatory environments, which would be reflected in stronger grid scoring for the regulatory framework and/or cost recovery factors for some US regulated utilities. We acknowledge that regulatory frameworks will need to accommodate new challenges and some may not support higher scoring under the methodology. Current examples of such challenges include utilities that are pursuing new nuclear construction projects in Georgia and South Carolina, public policy initiatives encouraging greater use of renewable energy, and the growth of distributed generation. These new market developments will continue to require collaborative solutions on the part of utilities, regulators, and political stakeholders. New rate compacts and incentive pricing mechanisms will need to be implemented that maintain both electricity network reliability and the financial health of the incumbent utility. Our current view is that regulators and utilities will be able to reach reasonable agreements regarding these issues.

While we have a more favorable view of US utility regulation in general, we acknowledge that challenging regulatory decisions will continue to occur in some jurisdictions as they have in the past, whether for political, populist, economic , or other reasons. The state of Florida, for example, had a long track record of credit supportive utility regulation before political intervention in utility rate cases in 2010 caused a deterioration in that regulatory framework. Following the election of a new governor and a the appointment of several new utility commissioners, Florida's regulatory framework has improved and is again considered credit supportive. Similarly, the state of California had a very good regulatory regime before the California energy crisis in 2000-2001 led to a dramatic decline in its credit supportiveness. Partly as a result of the lessons learned and improvements made following that experience, California's utility regulatory framework is again considered to be strong. Because US utility regulation remains highly fragmented and is primarily implemented at the state level, scenarios such as these will continue to emerge and influence future rating actions.

Sector Has Experienced Few Defaults, While Recovery Has Been Extraordinarily High

While there have been selected instances of regulatory and political pressure leading to financial distress for utilities in some US states (California, Illinois, and Maryland, for example), the overall number of US regulated utility defaults have been extremely low. This has occurred despite the propensity of regulated utilities to be more likely to consider and pursue strategic bankruptcy filings at an earlier stage of distress compared to unregulated non-financial corporate issuers. In the few instances where this has occurred, the company has continued to operate as a going concern, while regulators and other parties work collaboratively to resolve issues, allowing the utility to eventually exit bankruptcy proceedings.

The essential nature of the service that regulated utilities provide, as well as the critical nature of their generation, transmission, and distribution assets, makes it almost impossible to liquidate or otherwise disaggregate a utility during bankruptcy proceedings. As result, in the few regulated utility defaults that have occurred in the US, holders of secured debt eventually recovered 100% of principal and interest on a nominal basis in most cases. Recovery on other classes of debt has also been very high. This has been documented in Moody's default and recovery studies. Although not a key driver of our evolving overall view of US utility credit risk, these studies support and corroborate our view that ratings in the US regulated utility sector could be higher.

In 2009, we published a default study on the regulated utility industry entitled "Default, Recovery, and Credit Loss Rates for Regulated Utilities, 1983-2008". This study concluded that the history of regulated utility defaults indicates that Baa-rated regulated utilities have had significantly lower one-year default rates than Baa-rated nonfinancial corporate issuers, while A-rated utilities have had modestly higher one-year default rates than A-rated nonfinancial corporate issuers. Regulated utilities have also experienced lower loss given default rates (and, by definition, higher recovery rates) than other corporate issuers. Overall, this regulated utility default study showed that regulated utilities have experienced lower credit losses than non-financial, non-utility corporate issuers.

More recently, in December 2012 we published our first report on the historical credit performance of Moody's rated long-term infrastructure debts entitled "Infrastructure Default and Recovery Rates, 1983-2012H1." The study compared historical cumulative default and recovery rates for a broader set of infrastructure debts, including US regulated utilities, with non-financial corporate issuers. Like the previous regulated utility default study discussed above, the infrastructure default study also showed that A-rated corporate infrastructure debts have higher one year default rates but lower losses given default than non-financial corporate issuers, while Baa-rated corporate infrastructure debts (representing the higher proportion of corporate infrastructure debts) have very similar one year default rates as Baa-rated non-financial corporate debts. However, as recoveries have been better among the infrastructure debts, total credit loss rates have been about 30% lower than those of non-financial corporate debts, although in absolute terms they are of the same order of magnitude, indicating overall comparability in performance.

Credit loss rates for Ba-rated corporate infrastructure debts (representing a small proportion of corporate infrastructure debts) are lower than for non-financial corporate debts. This is driven by regulated utilities' (the major sub-factor of all Ba-rated infrastructure corporate debts) very low propensity to default and their high recovery rates. All other Ba-rated corporate infrastructure debts have credit loss rates similar to their non-financial corporate counterparts.

US Utility Financial Metrics Are Higher Than Similarly Rated International Utility Peers

In comparing financial ratios we use in the rating methodology for Regulated Electric and Gas Utilities of approximately 150 utility companies in several developed international jurisdictions with credit supportive regulatory frameworks (including Canada and Japan), US regulated utilities exhibit stronger ratios relative to similarly rated regulated international peers. For example, US utilities produce ratios of cash flow to debt that are almost twice as high as similarly rated international peers. The analysis included utilities with senior unsecured ratings in the A or Baa rating categories, and included electric, gas, networks, and water utilities, using historical financial data from Moody's Financial Metrics, as adjusted.

EXHIBIT 3

	Average (2005 - 2012)		Year-end 2012	
Jurisdiction	**CFO / debt**	**FFO / debt**	**CFO / debt**	**FFO / debt**
Average of international peers (A/Baa)	12%	12%	11%	10%
US - vertically integrated (A/Baa)	22%	23%	24%	23%
US - T&D, LDC (A/Baa)	18%	19%	19%	19%

Source: Moody's Financial Metrics

We note that federal tax policies, including accelerated bonus depreciation, have helped increase cash flows for many US utilities in recent years. But even if we exclude these benefits, in this example, by reducing the ratio of cash flow to debt by 300 basis points as a simplifying assumption, we still see more robust cash flow to debt ratios, roughly 50% higher than international peers.

EXHIBIT 4

	Average (2005 - 2012)		Year-end 2012	
Jurisdiction	**CFO / debt**	**FFO / debt**	**CFO / debt**	**FFO / debt**
Average of international peers (A/Baa)	12%	12%	11%	10%
US - vertically integrated (A/Baa)	19%	20%	21%	20%
US - T&D, LDC (A/Baa)	15%	16%	16%	16%

Source: Moody's Financial Metrics

In addition, US regulated utilities have lower balance sheet leverage and a larger equity cushion to absorb losses than similarly rated international peers, which is in part driven by the respective regulatory framework. With that said, higher leverage exhibited by some of the international peers is a function of those specific regulatory environments and the overall rate recovery structure in those jurisdictions. US utilities also have a sizeable contribution towards their capitalization from generous federal tax policies through the use of deferred taxes.

EXHIBIT 5

	Average (2005 - 2012)			Year-end 2012		
Jurisdiction	Debt / Equity	Debt / Book Capitalization	Debt + Equity / Book Capitalization	Debt / Equity	Debt / Book Capitalization	Debt + Equity / Book Capitalization
Average of international peers (A/Baa)	223%	65%	94%	247%	66%	94%
US - vertically integrated (A/Baa)	116%	45%	84%	112%	43%	81%
US - T&D, LDC (A/Baa)	124%	45%	81%	125%	44%	78%

Source: Moody's Financial Metrics

Although we believe the wide differences in historical financial ratios is partly explained by the differences in regulatory framework, we are increasingly viewing the stronger US financials as more than mitigating the slightly higher overall regulatory risk profile that the US holds relative to its international peers that typically operate under a national regulatory regime.

In the table below, we show selected median financials for the 2005 – 2012 period against the year-end 2012 financials. The international peers saw a 23% increase in debt, a 29% increase in revenue, a 21% increase in assets and an 11% decline in CFO. In the US, we see an 18% increase in debt, a 2% decline in revenue, and a 20% and 28% increase in assets and CFO, respectively.

EXHIBIT 6

		2005 - 2012 Median Totals ($ Millions)				2012 total ($ Millions)			
Jurisdiction	Number of Companies	Debt	Revenue	Assets	CFO	Debt	Revenue	Assets	CFO
Total international utility peers	58	$309,566	$158,364	$513,109	$35,967	$374,061	$211,673	$628,912	$33,824
US - vertically integrated	57	$171,395	$166,941	$484,970	$35,271	$202,311	$171,198	$600,779	$48,044
US - T&D, LDC	38	$78,719	$79,523	$213,408	$14,229	$86,494	$67,511	$238,117	$16,712
Total US regulated utility	95	$250,114	$246,463	$698,378	$49,500	$288,805	$238,709	$838,896	$64,756
Total regulated utilities	153	$559,680	$404,828	$1,211,487	$85,467	$662,866	$450,383	$1,467,808	$98,580

Source: Moody's Financial Metrics

Credit Supportiveness of Some Regulatory Jurisdictions has Declined in Recent Years

In recent years we have perceived a decline in the credit supportiveness of some regulatory jurisdictions that we had previously viewed as highly credit supportive. For example, following the 2011 Fukushima nuclear disaster in Japan, we downgraded the ratings of nine Japanese utilities, partly reflecting our expectation of a less supportive Japanese government regulatory framework for these utilities going forward. At the same time, we re-evaluated the Japanese utility industry's relative position as a regulatory environment and modified the grid scoring for Japanese utilities accordingly.

While we continue to view the Japanese regulatory framework as credit supportive due to the strong support of the utilities by their key regulator, the Ministry of Economy, Trade, and Industry (METI), as well as the Japanese government, we felt it had become somewhat less supportive than before the

Fukushima crisis, particularly as it relates to nuclear power. As a result, we lowered the grid scoring for Factor 1 of the methodology, Regulatory Framework, to either Aa or A from Aaa, depending on each utility's particular circumstances. Based on our current view, Japan's electric utilities that have nuclear generation capabilities are currently scored A for this factor, due to the ongoing uncertainty associated with regard to nuclear generation, while in general the gas utilities and non-nuclear exposed electric utilities are currently still viewed as appropriately scored at the Aa level.

Our updated view was also reflected in the grid scoring for Factor 2 – Ability to Recover Costs and Earn Returns for Japan's utilities. Although Japanese utility regulation includes statutory provisions that insure the timely recovery of operating, capital, fuel and financing costs, plus a rate of return, there are some limitations on automatic fuel related rate increases for both electric and gas utilities. This limitation, in addition to some of the utilities expanding internationally and into non-utility businesses, resulted in our decision to slightly revise the grid scoring for this factor, with most of the utilities initially lowered to an A score from a Aa score.

Subsequently, the prolonged shut-down of nuclear plants in Japan and the resulting higher reliance on fossil fuels have significantly raised operating costs for those utilities previously reliant on nuclear power. Although some of the nuclear-dependent utilities have successfully raised their tariffs, the new rates are insufficient to return them to profitability, as they are based on cost structures that incorporate some nuclear restarts. As a result, the scoring of some of the nuclear dependent utilities for this grid factor was subsequently lowered to Baa.

Conclusion

The refinements we are proposing to make to our Regulated Electric and Gas Utilities Rating Methodology are intended to provide additional granularity on individual factor grid scores by adding new sub-factors and to increase the relative weighting of the financial metrics when determining the grid-indicated rating. The methodology will continue to emphasize both regulatory risk and financial performance. The grid that is part of the methodology will continue to focus on the same four factors: regulatory framework, ability to recover costs and earn returns, diversification, and financial strength. The proposed refinements are not expected to lead to any rating changes. Comments on these refinements are welcome using the instructions on the cover page of this document.

At the same time, and unrelated to the update of the rating methodology, we are seeking comment on our view that the relative credit supportiveness of the US utility regulatory framework has improved, and that we should assess regulatory risks more favorably for US utilities. Improvements include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, generally fair and open relationships between utilities and regulators, and the demonstration of a strong judicial framework. As a result, we intend to take a more positive view of US utilities in factoring regulatory risks into ratings. This would also be reflected in higher grid scoring for utility regulatory frameworks and cost recovery provisions under the rating methodology. Our more favorable view of US regulation relative to other global jurisdictions is expected to lead to a one notch upgrade of most US regulated utilities, with some exceptions. In most cases, we would expect all of the debt classes of a utility's capital structure to be upgraded by the same number of notches, although there could be limited exceptions. The US utility sector's low number of defaults, high recovery levels, and comparatively strong financial metrics provide additional corroboration for our view that ratings should generally be higher. Comments on our evolving view of US utility regulation are also welcome using the instructions on the cover page of this document.

Appendix A: Preliminary Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings to Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa	
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a matter that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. . There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.	

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa	
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may be credit supportive, but often unenforceable. The regulator's authority may have be seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.	

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of unwillingness of regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy , but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa	
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourages investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.	

Factor 3: Diversification (10%)

	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	"Challenged Sources" are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	"Threatened Sources" are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

*10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

	Sub-Factor Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
(CFO pre-WC + Interest) / Interest	7.5%	≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
(CFO pre-WC) / Debt	15%	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
(CFO pre-WC – Dividends) / Debt	10%	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
Debt / Capitalization *	7.5%	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
Debt / RAV *		< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 85%	85% - 95%	≥ 95%

* The use of Debt / Capitalization or Debt / Regulated Asset Value (RAV) will depend largely on the regulatory regime in which the utility operates. Debt / Capitalization is currently used for most of the issuers rated under this methodology, because in many regions (currently including North America and many Asian countries) RAV does not exist. Where RAV exists, the Debt / RAV ratio may be preferable. The regulated asset base is comprised of the physical assets that are used to provide regulated distribution services, and the RAV represents the value (determined by regulators) on which the utility is permitted to earn a return. RAV can be calculated in various ways, using different rules that can be revised periodically, depending on the regulatory regime. Where RAV is calculated using consistent rules, we view Debt / RAV as the better credit measure and use it for this sub-factor. Where RAV does not exist or the method of calculation is subject to arbitrary or unpredictable revisions, we use Debt / Capitalization.

Appendix B: "Challenged" and "Threatened" Generation Sources

By "Challenged Sources", we mean generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe that plant closure is likely.

By "Threatened Sources", we mean generation plants that are not currently able or permitted to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US for which retro-fitting to meet mercury and air toxics standards is not economically viable or cannot be achieved by the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

Moody's Related Research

Rating Methodology:

» Regulated Electric and Gas Utilities, August 2009 (118481)

Cross-Sector Rating Methodologies:

» Loss Given Default for Speculative-Grade Non-Financial Companies in the US, Canada, and EMEA, June 2009 (114838)

» Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers, February 2007 (102248)

Special Comments:

» Default, Recovery, and Credit Loss Rates for Regulated Utilities, 1983-2008, May 2009 (115424)

» Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, June 2010 (125664)

» Cost Recovery Provisions Key to U.S. Investor Owned Utility Ratings and Credit Quality, June 2010 (122304)

» Liquidity: A Key Component to Investor-Owned Utility Ratings and Credit Quality Evaluating a Utility's Liquidity Profile, September 2010 (127546)

» Re-Evaluating Japanese Utility Credit Quality post-Fukushima, July 2011 (133194)

» Pacific Northwest Utilities: Regulatory Support Paves Way for Improving Credit Profiles, November 2011 (146170)

» Infrastructure Default and Recovery Rates, 1983-2012H1 December 2012 (146791)

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 INVESTORS SERVICE

Report Number: 157660

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Attachment 4.9

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 5.10

Canada Long-Horizon Equity Risk Premia

Long-Horizon Equity Risk Premia in Local Currency (Canadian Dollar – CAD) in Percent

End Date \ Start Date	1919	1920	1925	1930	1935	1940	1945	1950	1955	1960	1965	1970	1975	1980	1985	1990	1995	2000	2005	2010	2014
1997	5.7	5.6	5.9	5.0	5.9	5.8	6.1	5.6	4.0	3.5	2.8	3.0	4.2	1.5	3.0	2.5	13.7				
1998	5.5	5.5	5.8	4.9	5.7	5.6	5.9	5.4	3.8	3.3	2.6	2.7	3.8	1.2	2.4	1.7	9.2				
1999	6.0	6.0	6.2	5.4	6.3	6.2	6.5	6.1	4.6	4.3	3.6	4.0	5.3	3.2	5.0	5.6	15.4				
2000	5.9	5.9	6.2	5.4	6.2	6.2	6.5	6.0	4.6	4.2	3.6	3.9	5.2	3.2	4.9	5.4	13.4	3.3			
2001	5.6	5.6	5.8	5.0	5.8	5.7	6.0	5.5	4.0	3.6	3.0	3.2	4.3	2.1	3.4	3.2	8.5	-8.8			
2002	5.3	5.3	5.5	4.7	5.4	5.3	5.6	5.0	3.5	3.1	2.4	2.5	3.4	1.1	2.1	1.4	5.0	-12.3			
2003	5.5	5.5	5.7	4.9	5.7	5.6	5.8	5.3	3.9	3.5	2.9	3.0	4.0	2.0	3.1	2.9	6.9	-3.8			
2004	5.6	5.5	5.7	5.0	5.7	5.7	5.9	5.4	4.0	3.6	3.0	3.2	4.2	2.3	3.4	3.3	7.1	-1.3			
2005	5.7	5.7	5.9	5.2	5.9	5.9	6.1	5.7	4.3	4.0	3.5	3.7	4.7	3.0	4.3	4.4	8.3	2.4	21.0		
2006	5.8	5.8	6.0	5.3	6.1	6.0	6.3	5.8	4.5	4.2	3.7	4.0	5.0	3.4	4.7	4.9	8.8	4.0	17.4		
2007	5.8	5.8	6.0	5.3	6.1	6.0	6.3	5.8	4.6	4.3	3.8	4.0	5.1	3.5	4.7	5.0	8.6	4.3	13.6		
2008	5.4	5.3	5.5	4.8	5.5	5.4	5.6	5.1	3.8	3.5	2.9	3.0	3.9	2.1	3.1	2.9	5.4	-0.1	1.4		
2009	5.6	5.6	5.8	5.1	5.8	5.8	6.0	5.5	4.3	4.0	3.5	3.7	4.6	3.1	4.1	4.2	7.1	2.9	7.1		
2010	5.7	5.7	5.9	5.2	5.9	5.8	6.1	5.6	4.4	4.1	3.6	3.9	4.8	3.3	4.4	4.6	7.3	3.6	7.7	11.1	
2011	5.5	5.5	5.7	5.0	5.6	5.6	5.8	5.3	4.1	3.8	3.3	3.5	4.3	2.8	3.8	3.7	6.1	2.2	4.7	-1.1	
2012	5.5	5.5	5.7	5.0	5.6	5.6	5.8	5.3	4.1	3.8	3.3	3.5	4.3	2.9	3.8	3.8	6.1	2.4	4.8	0.9	
2013	5.5	5.5	5.7	5.0	5.7	5.6	5.8	5.4	4.2	3.9	3.5	3.7	4.5	3.1	4.1	4.1	6.3	3.1	5.5	3.5	
2014	5.6	5.6	5.8	5.1	5.7	5.7	5.9	5.5	4.3	4.0	3.6	3.8	4.6	3.3	4.2	4.3	6.4	3.4	5.8	4.5	8.7

Source of underlying data: 1.) Morningstar *Direct* database. Used with permission. All calculations performed by Duff & Phelps LLC.

Canada Long-Horizon Equity Risk Premia

Long-Horizon Equity Risk Premia in Local Currency (Canadian Dollar – CAD) in Percent

End Date \ Start Date	1919	1920	1925	1930	1935	1940	1945	1950	1955	1960	1965	1970	1975	1980	1985	1990	1995	2000	2005	2010	2014
1958	7.8	7.8	8.7	7.2	9.9	10.7	13.5	14.8	9.2												
1959	7.6	7.6	8.5	7.0	9.5	10.2	12.6	13.3	7.3												
1960	7.4	7.4	8.1	6.6	9.0	9.5	11.6	11.8	5.5	-3.5											
1961	7.9	7.9	8.6	7.3	9.7	10.3	12.5	13.1	8.7	12.0											
1962	7.4	7.4	8.1	6.7	8.9	9.4	11.2	11.2	6.1	4.0											
1963	7.5	7.5	8.2	6.8	8.9	9.4	11.1	11.1	6.6	5.6											
1964	7.7	7.7	8.5	7.2	9.3	9.8	11.6	11.7	7.9	8.5											
1965	7.6	7.6	8.3	7.0	9.1	9.5	11.1	11.1	7.3	7.4	1.6										
1966	7.2	7.2	7.8	6.5	8.4	8.7	10.0	9.7	5.7	4.5	-5.5										
1967	7.3	7.3	7.9	6.7	8.5	8.8	10.1	9.8	6.2	5.5	0.4										
1968	7.5	7.5	8.1	6.9	8.7	9.1	10.4	10.2	6.9	6.6	4.3										
1969	7.2	7.1	7.7	6.5	8.2	8.5	9.6	9.2	5.9	5.2	1.8										
1970	7.0	7.0	7.6	6.4	8.0	8.2	9.3	8.8	5.5	4.7	1.5	0.1									
1971	7.0	7.0	7.5	6.3	8.0	8.2	9.1	8.7	5.5	4.8	2.1	3.0									
1972	7.4	7.3	7.9	6.8	8.4	8.7	9.7	9.4	6.7	6.4	5.1	10.6									
1973	7.0	7.0	7.5	6.4	8.0	8.1	9.0	8.6	5.8	5.2	3.4	5.4									
1974	6.3	6.2	6.7	5.5	6.9	6.9	7.6	6.8	3.7	2.5	-0.5	-2.7									
1975	6.3	6.3	6.7	5.6	6.9	7.0	7.6	6.9	4.0	3.0	0.4	-0.7	9.4								
1976	6.2	6.2	6.6	5.4	6.8	6.8	7.4	6.7	3.8	2.8	0.4	-0.6	4.6								
1977	6.1	6.0	6.4	5.3	6.6	6.5	7.1	6.4	3.5	2.5	0.2	-0.9	2.3								
1978	6.3	6.3	6.7	5.6	6.9	6.9	7.5	6.9	4.3	3.5	1.7	1.7	7.1								
1979	6.9	6.9	7.3	6.3	7.6	7.8	8.5	8.0	5.8	5.4	4.3	5.6	13.9								
1980	7.0	7.0	7.4	6.4	7.8	7.9	8.6	8.2	6.0	5.7	4.8	6.2	13.6	12.4							
1981	6.5	6.5	6.9	5.9	7.1	7.1	7.7	7.2	4.9	4.4	3.1	3.7	8.3	-5.7							
1982	6.3	6.2	6.6	5.6	6.8	6.8	7.3	6.7	4.4	3.8	2.5	2.7	6.2	-6.7							
1983	6.5	6.5	6.9	5.9	7.1	7.1	7.6	7.1	5.0	4.6	3.5	4.1	7.9	0.5							
1984	6.2	6.2	6.5	5.5	6.7	6.6	7.1	6.5	4.4	3.8	2.7	2.9	5.8	-2.3							
1985	6.3	6.3	6.6	5.6	6.7	6.8	7.2	6.7	4.6	4.1	3.1	3.5	6.3	0.0	11.5						
1986	6.2	6.2	6.5	5.5	6.6	6.6	7.0	6.5	4.5	4.0	2.9	3.2	5.7	-0.1	5.5						
1987	6.1	6.0	6.4	5.4	6.5	6.4	6.8	6.3	4.3	3.8	2.7	3.0	5.2	-0.2	3.2						
1988	6.0	5.9	6.2	5.3	6.3	6.3	6.6	6.1	4.1	3.6	2.5	2.7	4.7	-0.4	1.9						
1989	6.0	6.0	6.3	5.4	6.4	6.4	6.7	6.2	4.3	3.8	2.9	3.2	5.1	0.7	3.8						
1990	5.6	5.6	5.9	4.9	5.9	5.8	6.1	5.5	3.6	3.0	1.9	2.0	3.4	-1.3	-0.5	-22.1					
1991	5.6	5.6	5.8	4.9	5.8	5.7	6.0	5.4	3.5	2.9	1.9	1.9	3.3	-1.1	-0.3	-10.4					
1992	5.4	5.3	5.6	4.6	5.5	5.4	5.7	5.0	3.1	2.5	1.4	1.3	2.5	-1.9	-1.7	-10.8					
1993	5.5	5.5	5.7	4.8	5.7	5.6	5.8	5.2	3.4	2.9	1.9	1.9	3.1	-0.7	0.2	-4.3					
1994	5.4	5.3	5.6	4.6	5.5	5.4	5.6	5.0	3.2	2.7	1.7	1.7	2.8	-0.9	-0.3	-4.3					
1995	5.4	5.3	5.6	4.7	5.5	5.4	5.7	5.1	3.3	2.8	1.9	1.9	3.0	-0.4	0.4	-2.4	6.9				
1996	5.6	5.6	5.8	4.9	5.8	5.7	6.0	5.4	3.8	3.3	2.5	2.6	3.9	0.9	2.2	1.1	14.7				

Source of underlying data: 1.) Morningstar *Direct* database. Used with permission. All calculations performed by Duff & Phelps LLC.

Canada Long-Horizon Equity Risk Premia

Long-Horizon Equity Risk Premia in Local Currency (Canadian Dollar – CAD) in Percent

End Date	Start Date 1919	1920	1925	1930	1935	1940	1945	1950	1955	1960	1965	1970	1975	1980	1985	1990	1995	2000	2005	2010	2014
1919	7.8																				
1920	-2.1	-12.0																			
1921	-3.6	-9.3																			
1922	2.1	0.3																			
1923	2.2	0.9																			
1924	2.9	2.0																			
1925	4.7	4.2	15.2																		
1926	6.6	6.4	17.4																		
1927	10.3	10.6	25.0																		
1928	12.1	12.6	25.9																		
1929	9.5	9.7	17.4																		
1930	5.7	5.6	8.6	-35.6																	
1931	2.4	2.0	2.0	-36.6																	
1932	1.0	0.4	-0.5	-30.4																	
1933	4.0	3.8	4.7	-11.1																	
1934	4.8	4.6	5.9	-5.6																	
1935	6.1	6.0	7.8	-0.1	27.0																
1936	7.0	7.0	9.0	3.1	24.7																
1937	5.6	5.5	6.9	0.3	10.1																
1938	5.7	5.5	6.8	0.9	9.1																
1939	5.2	5.1	6.2	0.6	6.7																
1940	4.0	3.8	4.4	-1.5	1.8	-22.4															
1941	3.8	3.6	4.1	-1.5	1.4	-11.8															
1942	4.1	3.9	4.4	-0.5	2.6	-4.2															
1943	4.6	4.4	5.1	0.7	4.2	1.0															
1944	4.8	4.7	5.3	1.3	4.8	2.9															
1945	5.8	5.8	6.7	3.3	7.4	7.9	33.1														
1946	5.5	5.4	6.2	2.9	6.4	6.2	14.5														
1947	5.2	5.1	5.8	2.6	5.8	5.2	8.9														
1948	5.4	5.3	6.0	2.9	6.0	5.6	9.0														
1949	5.8	5.8	6.5	3.8	6.9	7.0	11.1														
1950	7.1	7.0	8.0	5.8	9.3	10.5	16.9	45.6													
1951	7.5	7.5	8.5	6.5	10.0	11.4	17.4	33.2													
1952	7.1	7.1	8.0	6.0	9.2	10.2	14.8	20.8													
1953	6.9	6.9	7.7	5.7	8.7	9.4	13.0	15.2													
1954	7.7	7.7	8.6	6.9	10.0	11.1	15.2	19.3													
1955	8.2	8.2	9.2	7.6	10.7	12.0	16.1	20.2	24.7												
1956	8.2	8.2	9.2	7.7	10.7	11.8	15.6	18.7	17.1												
1957	7.3	7.3	8.2	6.5	9.1	9.8	12.5	13.3	3.2												

Source of underlying data: 1.) Morningstar *Direct* database. Used with permission. All calculations performed by Duff & Phelps LLC.

United States Long-Horizon Equity Risk Premia

Long-Horizon Equity Risk Premia in U.S. Dollars (USD, which is also the "Local" currency)
in Percent

End Date \ Start Date	1926	1930	1935	1940	1945	1950	1955	1960	1965	1970	1975	1980	1985	1990	1995	2000	2005	2010	2014
1926	7.9																		
1927	21.0																		
1928	27.5																		
1929	17.6																		
1930	8.5	-28.2																	
1931	-0.7	-37.4																	
1932	-2.3	-28.9																	
1933	4.3	-9.0																	
1934	3.3	-8.1																	
1935	7.5	0.7	44.9																
1936	9.6	5.1	38.0																
1937	5.7	-0.3	12.8																
1938	7.4	2.9	16.7																
1939	6.7	2.3	12.8																
1940	5.5	1.0	8.7	-12.0															
1941	4.3	-0.2	5.5	-12.8															
1942	5.1	1.2	7.0	-2.6															
1943	6.1	2.8	8.9	3.9															
1944	6.7	3.8	9.7	6.6															
1945	8.1	5.7	11.9	11.2	34.1														
1946	7.2	4.7	10.1	8.2	12.0														
1947	7.0	4.7	9.6	7.6	9.2														
1948	6.9	4.6	9.1	7.1	7.7														
1949	7.3	5.2	9.6	8.0	9.4														
1950	8.2	6.4	10.9	10.0	12.8	29.6													
1951	8.7	7.0	11.5	11.0	14.1	25.6													
1952	8.9	7.4	11.7	11.3	14.3	22.3													
1953	8.5	7.0	10.9	10.2	12.3	15.8													
1954	9.9	8.7	12.9	12.9	16.0	22.6													
1955	10.5	9.4	13.6	13.9	17.2	23.6	28.8												
1956	10.3	9.2	13.2	13.3	16.0	20.8	16.2												
1957	9.5	8.4	12.0	11.7	13.7	16.4	6.1												
1958	10.5	9.5	13.1	13.2	15.6	19.0	14.6												
1959	10.4	9.4	12.9	13.0	15.1	17.9	13.2												

Source of underlying data: 1.) Morningstar *Direct* database. Used with permission. All calculations performed by Duff & Phelps LLC.

United States Long-Horizon Equity Risk Premia

Long-Horizon Equity Risk Premia in U.S. Dollars (USD, which is also the "Local" currency) in Percent

	Start Date																		
End Date	1926	1930	1935	1940	1945	1950	1955	1960	1965	1970	1975	1980	1985	1990	1995	2000	2005	2010	2014
1960	10.0	9.0	12.3	12.2	13.9	15.9	10.4	-3.8											
1961	10.4	9.4	12.7	12.7	14.4	16.5	12.2	9.6											
1962	9.7	8.8	11.8	11.6	12.9	14.3	9.1	2.2											
1963	10.0	9.1	12.0	11.9	13.3	14.6	10.2	6.4											
1964	10.0	9.2	12.0	11.9	13.2	14.5	10.4	7.6											
1965	10.0	9.1	11.9	11.7	13.0	14.1	10.2	7.7	8.3										
1966	9.4	8.5	11.1	10.8	11.7	12.4	8.1	4.5	-3.1										
1967	9.6	8.8	11.3	11.1	12.1	12.8	9.0	6.4	4.4										
1968	9.5	8.7	11.2	10.9	11.8	12.4	8.8	6.3	4.7										
1969	9.0	8.1	10.4	10.0	10.7	11.1	7.2	4.2	0.8										
1970	8.7	7.9	10.1	9.6	10.2	10.4	6.6	3.6	0.2	-2.9									
1971	8.7	7.9	10.0	9.6	10.1	10.3	6.7	3.9	1.3	2.5									
1972	8.8	8.0	10.1	9.7	10.2	10.4	7.0	4.6	2.8	6.1									
1973	8.2	7.3	9.3	8.8	9.2	9.1	5.5	2.8	0.1	-0.7									
1974	7.3	6.4	8.2	7.6	7.7	7.4	3.6	0.4	-3.3	-7.3									
1975	7.8	6.9	8.7	8.2	8.4	8.2	4.8	2.2	-0.3	-1.2	29.2								
1976	7.9	7.1	8.9	8.4	8.7	8.5	5.3	3.0	1.1	1.2	22.6								
1977	7.5	6.6	8.4	7.8	8.0	7.7	4.5	2.0	-0.1	-0.7	10.3								
1978	7.3	6.5	8.1	7.5	7.7	7.4	4.2	1.8	-0.2	-0.8	7.4								
1979	7.4	6.6	8.2	7.6	7.7	7.5	4.4	2.2	0.5	0.3	7.9								
1980	7.6	6.9	8.5	8.0	8.2	7.9	5.1	3.2	1.8	2.3	10.3	22.5							
1981	7.2	6.4	8.0	7.4	7.5	7.2	4.3	2.3	0.8	0.7	6.5	3.0							
1982	7.2	6.4	8.0	7.4	7.5	7.2	4.5	2.6	1.2	1.3	6.7	4.7							
1983	7.3	6.6	8.0	7.5	7.6	7.4	4.7	3.0	1.7	2.1	7.3	6.6							
1984	7.1	6.3	7.8	7.2	7.3	7.0	4.4	2.6	1.4	1.6	6.0	4.2							
1985	7.3	6.6	8.0	7.5	7.6	7.4	4.9	3.3	2.3	2.7	7.3	6.9	20.5						
1986	7.4	6.6	8.1	7.6	7.7	7.4	5.1	3.5	2.6	3.2	7.5	7.3	15.1						
1987	7.2	6.5	7.9	7.3	7.4	7.2	4.8	3.3	2.4	2.8	6.7	6.0	9.2						
1988	7.2	6.5	7.9	7.3	7.4	7.2	4.9	3.5	2.6	3.1	6.8	6.2	8.8						
1989	7.5	6.8	8.1	7.7	7.8	7.6	5.4	4.1	3.4	4.1	7.9	7.9	11.6						
1990	7.2	6.5	7.8	7.3	7.4	7.1	5.0	3.6	2.9	3.3	6.7	6.1	7.8	-11.3					
1991	7.4	6.7	8.0	7.6	7.7	7.5	5.4	4.2	3.6	4.2	7.6	7.5	9.9	5.5					
1992	7.3	6.6	7.9	7.4	7.5	7.3	5.3	4.1	3.5	4.0	7.2	6.9	8.7	3.8					
1993	7.2	6.6	7.8	7.4	7.4	7.2	5.2	4.1	3.4	4.0	7.0	6.6	8.0	3.6					

Source of underlying data: 1.) Morningstar *Direct* database. Used with permission. All calculations performed by Duff & Phelps LLC.

United States Long-Horizon Equity Risk Premia

Long-Horizon Equity Risk Premia in U.S. Dollars (USD, which is also the "Local" currency) in Percent

End Date \ Start Date	1926	1930	1935	1940	1945	1950	1955	1960	1965	1970	1975	1980	1985	1990	1995	2000	2005	2010	2014
1994	7.0	6.4	7.6	7.1	7.2	6.9	5.0	3.8	3.2	3.6	6.4	5.9	6.7	1.8					
1995	7.4	6.7	8.0	7.5	7.6	7.4	5.6	4.5	4.0	4.6	7.5	7.4	8.8	6.5	30.0				
1996	7.5	6.9	8.1	7.7	7.8	7.6	5.8	4.8	4.4	5.1	7.9	7.9	9.5	8.0	23.4				
1997	7.8	7.2	8.4	8.0	8.2	8.0	6.3	5.4	5.1	5.9	8.7	9.0	10.8	10.3	24.5				
1998	8.0	7.4	8.6	8.3	8.4	8.3	6.7	5.9	5.6	6.4	9.3	9.7	11.7	11.7	24.1				
1999	8.1	7.5	8.7	8.4	8.6	8.5	6.9	6.1	5.9	6.7	9.6	10.0	11.9	12.1	22.3				
2000	7.8	7.2	8.4	8.0	8.1	8.0	6.4	5.6	5.3	6.0	8.6	8.8	10.2	9.5	16.0	-15.6			
2001	7.4	6.9	8.0	7.6	7.7	7.5	5.9	5.0	4.7	5.3	7.6	7.6	8.6	7.3	11.2	-16.5			
2002	7.0	6.4	7.5	7.0	7.1	6.8	5.2	4.3	3.8	4.3	6.4	6.0	6.6	4.6	6.4	-20.2			
2003	7.2	6.6	7.7	7.3	7.4	7.2	5.6	4.7	4.3	4.9	7.0	6.8	7.5	6.0	8.3	-9.2			
2004	7.2	6.6	7.7	7.3	7.3	7.1	5.6	4.7	4.4	4.9	6.9	6.7	7.4	6.0	8.1	-6.2			
2005	7.1	6.5	7.6	7.2	7.2	7.0	5.5	4.6	4.3	4.8	6.7	6.5	7.0	5.6	7.4	-5.1	0.2		
2006	7.1	6.6	7.6	7.2	7.3	7.1	5.6	4.8	4.4	4.9	6.9	6.7	7.2	5.9	7.7	-2.8	5.7		
2007	7.1	6.5	7.5	7.1	7.2	7.0	5.5	4.7	4.4	4.8	6.7	6.4	6.9	5.6	7.1	-2.4	4.0		
2008	6.5	5.9	6.9	6.4	6.4	6.2	4.6	3.7	3.3	3.6	5.2	4.8	4.9	3.2	3.7	-6.7	-7.4		
2009	6.7	6.1	7.1	6.7	6.7	6.4	5.0	4.1	3.8	4.1	5.8	5.4	5.6	4.2	5.0	-3.7	-1.3		
2010	6.7	6.2	7.1	6.7	6.7	6.5	5.1	4.3	3.9	4.3	5.9	5.6	5.8	4.5	5.3	-2.4	0.7	10.8	
2011	6.6	6.1	7.0	6.6	6.6	6.4	4.9	4.2	3.8	4.1	5.7	5.3	5.6	4.2	4.9	-2.4	0.4	4.6	
2012	6.7	6.2	7.1	6.7	6.7	6.5	5.1	4.3	4.0	4.4	5.9	5.6	5.9	4.6	5.4	-1.1	2.0	7.6	
2013	7.0	6.5	7.4	7.0	7.0	6.8	5.5	4.8	4.5	4.9	6.5	6.3	6.7	5.6	6.7	1.1	5.1	13.1	
2014	7.0	6.5	7.4	7.0	7.1	6.9	5.6	4.9	4.6	5.1	6.6	6.4	6.8	5.8	6.8	1.7	5.6	12.5	10.4

Source of underlying data: 1.) Morningstar *Direct* database. Used with permission. All calculations performed by Duff & Phelps LLC.

Canada

NOTE: In the *2015 International Valuation Handbook – Guide to Cost of Capital* (this book), the time horizon over which the long-term ERP estimates for Canada are calculated has been extended to 1919–2014 (previously calculated from 1970–present in the *2014 International Valuation Handbook – Guide to Cost of Capital*). Note that if the analyst wishes to select a long-term ERP measured over the same time frame as the majority of the other subject countries' ERPs are measured over (1970–present in most cases), that information is *still* provided in the Canada long-term ERP tables. However, if the analyst requires a long-term ERP measured over longer periods (pre-1970), this information is also now available.

Equity Series: From 1919 to 1969, the equity series used is Dimson, Marsh, Staunton (DMS) equity returns for Canada.[3.26] The main data source for DMS equity returns for Canada from 1926 forward is Panjer and Tan (2002).[3.27] Prior to 1926, the primary source for DMS equity returns for Canada the equity returns series produced by Moore (2012).[3.28] From 1970 to present, the equity series used is the MSCI Canada GR Index (total return) series. The MSCI Canada Index is designed to measure the performance of the large and mid-cap segments of the Canada market. With 95 constituents, the index covers approximately 85% of the free float-adjusted market capitalization in Canada.

Long-Horizon Risk-free Rate: From 1919 to 1957, long-term government securities data from the Bank of Canada Data and Statistics Office were used.[3.29] From 1958 to present, the long-horizon risk-free series used is the IMF Canada LT Gvt Income Return series, calculated from government bond yield issues with original maturity of 10 years or more. It is calculated based on average yield to maturity.

Short-Horizon Risk-free Rate: The short-horizon risk-free series used is the IMF Canada Tbill series. The series is based on the weighted average of the yields on successful bids for 3-month bills. Monthly data relate to the tender rates of the last Wednesday of the month.

3.26 Elroy Dimson, Paul Marsh, and Mike Staunton, *Credit Suisse Global Investment Returns Sourcebook 2015* (Credit Suisse, 2015).

3.27 Panjer, Harry, and Ken Seng Tan, 2002. *Report on Canadian Economic Statistics 1924–2001*, Canadian Institute of Actuaries. [Updated in: *Report on Canadian Economic Statistics 1924–2008*].

3.28 Moore, Lyndon, 2012, "World Financial Markets", 1900–25, Unpublished manuscript.

3.29 Source: Bank of Canada website at:
http://www.bankofcanada.ca/rates/interest-rates/selected-historical-interest-rates/
Source document for 1919–1935, 1936–1948, and 1949–1957 long-term government securities data: Government of Canada Marketable Bonds, Average Yield, Over 10 years – V122487 – Jan. 1919; "selected_historical_v122487.pdf", Bank of Canada, Data and Statistics Office. Rates for 1919 to 1935 are "monthly averages for selected long-term bond issues". Rates from 1936–1948 are "theoretical 15-year bond yields based on middle of the market quotations". Rates from 1949–1957 "refer to direct debt payable in Canadian dollars, excluding extendible issues and Canada Savings Bonds. Prior to 1975 some extendible issues are included but their inclusion does not materially affect the average yields. The rates shown from 1949 to 1958 are arithmetic averages of yields at month-end".

United States

NOTE: In the *2015 International Valuation Handbook – Guide to Cost of Capital* (this book), the time horizon over which the long-term ERP estimates for the United States are calculated has been extended to 1926–2014 (previously calculated from 1970–present in the *2014 International Valuation Handbook – Guide to Cost of Capital*). The 1926–2014 time horizon matches the time horizon over which the long-term historical ERP is calculated and reported in Appendix 3, "CRSP Deciles Size Premia Study: Key Variables", of the *2015 Valuation Handbook – Guide to Cost of Capital*, and matches the time frame over which the long-term historical ERP was calculated and reported on the "back page" of the (now discontinued) Morningstar/Ibbotson *SBBI Valuation Yearbook*. If the analyst wishes to select a long-term ERP measured over the same time horizon as the majority of the other subject countries' long-term historical ERPs are measured in Exhibit 1 (1970–present in most cases), that information is still provided in the U.S. long-term ERP tables. However, if the analyst requires a long-term ERP measured over longer periods (pre-1970), this information is also now available.

Equity Series: U.S. equities are represented by the Standard & Poor's S&P 500® Index (total return) series. The S&P 500 Index is a readily available, carefully constructed, market-value-weighted benchmark of common stock performance. Market-value-weighted means that the weight of each stock in the index, for a given month, is proportionate to its market capitalization (price times the number of shares outstanding) at the beginning of that month. Currently, this composite index includes 500 of the largest stocks (in terms of stock market value) in the United States; prior to March 1957 it consisted of 90 of the largest stocks.

Long-Horizon Risk-free Rate: The long-horizon risk-free series used is the IA SBBI US LT Govt IR USD series. The total returns on long-term government bonds from 1977 to present are constructed with data from The Wall Street Journal. The data from 1926–1976 are obtained from the Government Bond File at the Center for Research in Security Prices (CRSP) at the University of Chicago Graduate School of Business. To the greatest extent possible, a one-bond portfolio with a term of approximately 20 years and a reasonably current coupon – whose returns did not reflect potential tax benefits, impaired negotiability, or special redemption or call privileges – was used each year. Where "flower" bonds (tenderable to the Treasury at par in payment of estate taxes) had to be used, the bond with the smallest potential tax benefit was chosen. Where callable bonds had to be used, the term of the bond was assumed to be a simple average of the maturity and first call dates minus the current date.

The bond was "held" for the calendar year and returns were computed. From 1977 to present, the income return is calculated as the change in flat price plus any coupon actually paid from one period to the next, holding the yield constant over the period. As in the total return series, the exact number of days comprising the period is used. From 1926–1976, the income return for a given month is calculated as the total return minus the capital appreciation return.

Short-Horizon Risk-free Rate: The risk-free series used is the IA SBBI US 30 Day Treasury bill series. For the U.S. Treasury bill index, data from the Wall Street Journal are used from 1977–present; the CRSP U.S. Government Bond File is the source until 1976. Each month a one-bill portfolio containing the shortest term bill having not less than one month to maturity is constructed. (The bill's original term to maturity is not relevant.) To measure holding period returns for the one-bill portfolio, the bill is priced as of the last trading day of the previous month-end and as of the last trading day of the current month.

Currency Translation

Currency translation is applied only in cases in which a series not in the needed currency (specifically, USD or "local") is available.

Equities: MSCI provides a total return equity series in USD for each of the 16 countries presented here, and so for these series no currency translation was required. MSCI provides a total return equity series in local for each of the 16 countries presented here, and so for these series no currency translation was required. Dimson, Marsh, Staunton (DMS) total return equity series were available in USD and local for the five countries herein that utilized DMS series (Canada, Ireland, New Zealand, South Africa, and the United Kingdom), and again no currency translation was required for these series.

Risk-free Rates: IMF risk-free series in local currency for all short-horizon and long-horizon risk-free rate series were available, and so for these series no currency translation was required. These series were translated into USD currency.[3.35] Long-term Canadian risk-free security series prior to 1958 (specifically, 1919–1957), was available in CAD from the source (Bank of Canada Data and Statistics Office); these returns were translated into USD using USD/CAD exchange rates provided by the Dimson, Marsh, and Staunton (DMS) database.[3.36] Long-term United Kingdom risk-free security series prior to 1970 (specifically, 1900–1969), was available in GBP from the source (Bank of England); these returns were translated into USD using USD/GBP exchange rates provided by the Dimson, Marsh, and Staunton (DMS) database.

Exhibit 3.2 provides a summary of the data series used to calculate the historical ERPs presented in Data Exhibit 1, "2015 International Equity Risk Premia".

3.35 Source of currency conversion data: Morningstar *Direct* database. Exchange rate sources (as reported by Morningstar): 1960–1987 Main Economic Indicators Historical Statistics (Organization for Economic Cooperation & Development); 1988–present the *Wall Street Journal.*

3.36 As used in Elroy Dimson, Paul Marsh, and Mike Staunton, *Credit Suisse Global Investment Returns Sourcebook 2015* (Credit Suisse, 2015).

Exhibit 3.2: Data Series Used to Calculate the Equity Risk Premia (ERPs) Presented in Data Exhibit 1

Country	Long Horizon ERP Start Date	Short Horizon ERP Start Date	Equity Series 1 Source	Equity Series 2 Source	Long-Horizon Risk-Free Series 1 Source	Long-Horizon Risk-Free Series 2 Source	Short-Horizon Risk-Free Series 1 Source	Short-Horizon Risk-Free Series 2 Source
Australia	1970	1970	MSCI Australia GR		IMF Australia LT Gvt Inc Ret		IMF Australia ST Gvt	
Austria	1972 USD 1971 Local	1970	MSCI Austria GR		IMF Austria LT Gvt Inc Ret		IMF Austria Discount Rate - disc 1970-1998	IMF Euro Area 3 Mo Interbank Rate 1999-Present
Belgium	1970	1970	MSCI Belgium GR		IMF Belgium LT Gvt Inc Ret		IMF Belgium Money Mkt - disc 1970-1998	IMF Euro Area 3 Mo Interbank Rate 1999-Present
Canada	1919	1970	Dimson, Marsh, Staunton Canada Equity 1919-1969	MSCI Canada GR 1970-Present	Bank of Canada 1919-1957	IMF Canada LT Gvt Inc Ret 1958-Present	IMF Canada Tbill	
France	1970	1970*	MSCI France GR		IMF France LT Gvt Inc Ret		IMF France Money Mkt - disc 1970-1998	IMF Euro Area 3 Mo Interbank Rate 1999-Present
Germany	1970	1970	MSCI Germany GR		IMF Germany LT Gvt Inc Ret		IMF Germany Money Mkt 1970-2011	IMF Euro Area 3 Mo Interbank Rate 2012-Present
Ireland	1970	–	Dimson, Marsh, Staunton Ireland Equity 1970-1987	MSCI Ireland GR 1988-Present	IMF Ireland LT Gvt Inc Ret		–	
Italy	1970	1978	MSCI Italy GR		IMF Italy LT Gvt Inc Ret		IMF Italy Tbill	
Japan	1970	1970	MSCI Japan GR		IMF Japan LT Gvt Inc Ret		IMF Japan Money Mkt	
Netherlands	1970	–	MSCI Netherlands GR		IMF Netherlands LT Gvt Inc Ret		–	
New Zealand	1970	–	Dimson, Marsh, Staunton New Zealand Equity 1970-1987	MSCI New Zealand GR 1988-Present	IMF New Zealand LT Gvt Inc Ret		–	
South Africa	1971 USD 1970 Local	1971 USD** 1970 Local**	Dimson, Marsh, Staunton South Africa Equity 1970-1992	MSCI South Africa GR 1993–Present	IMF South Africa LT Gvt Inc Ret		IMF South Africa TBill	
Spain	1972 USD 1971 Local	1975	MSCI Spain GR		IMF Euro Area LT Gvt Inc Ret		IMF Spain Tbill TR 1975-Present	
Switzerland	1970	1981	MSCI Switzerland GR		IMF Switzerland LT Gvt Inc Ret		IMF Switzerland Tbill	
United Kingdom	1900	1970	Dimson, Marsh, Staunton United Kingdom Equity 1900-1969	MSCI U.K. GR 1970-Present	Bank of England 1900-1969	IMF U.K. LT Gvt Inc Ret 1970-Present	IMF U.K. Tbill	
United States	1926	1970	S&P 500 TR (IA Extended)		IA SBBI U.S. LT Gvt IR		IA SBBI U.S. 30 Day Tbill	

* 1986 short-horizon risk-free rate estimated (France)

** 1987 short-horizon risk-free rate estimated (South Africa)

Market Results Through
December 2014 and March 2015

2015
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Attachment 5.14

GLOBAL EVIDENCE ON THE EQUITY RISK PREMIUM

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One of the most important contemporary issues in corporate finance is the magnitude of the equity risk premium. The risk premium is the incremental return that shareholders require from holding risky equities rather than risk-free securities. The risk premium drives future equity returns and is the key determinant of the cost of capital.

Today, investors have more cause than ever to ask what returns they can expect from equities, and what the future risk-reward tradeoff is likely to be. Companies also need to answer this question in order to understand what returns their shareholders require from projects of differing risk. Regulators, too, need to know the cost of capital in order to set 'fair' rates of return for regulated industries.

This paper sheds light on this important issue by addressing two key questions: What has the size of the equity risk premium been historically? And what can we expect for the future? To answer these questions, we need to look at long periods of capital market history, and extend our horizons beyond just the United States. In this paper, we therefore present evidence for sixteen different countries over the 102-year period from 1900–2001.

The need for a long-run perspective

The need for a long-run perspective, and the dangers of focusing just on recent stock market history, are easily demonstrated. Over the last decade of the twentieth century, US equity investors more than trebled their initial stake. In real terms, they achieved a total return (capital gain plus reinvested dividends) of 14.2 percent per annum. During the last five years of the1990s, US equities achieved high returns in every year, varying from a low of twenty-one percent in 1996 to a high of thirty-six percent in 1995. Many investors became convinced that high corporate growth rates could be extrapolated into the indefinite future. With steady growth rates, equity risk appeared lower. Simultaneously, there appeared to be a decline in the premium sought by investors to compensate for exposure to equity market risk. This drove stock prices onward and upward. Surveys suggested that, in consequence, many investors expected long-run stock market returns to continue at double-digit percentage rates of return.

Then the technology bubble burst. Growth projections had been unrealistic. High growth expectations were seen to be associated with high risk. Investors demanded a larger reward for equity market risk exposure. Stock prices fell in 2000 and then again in 2001, with no respite yet in 2002. With markets having fallen, investors started to project lower returns for the future.

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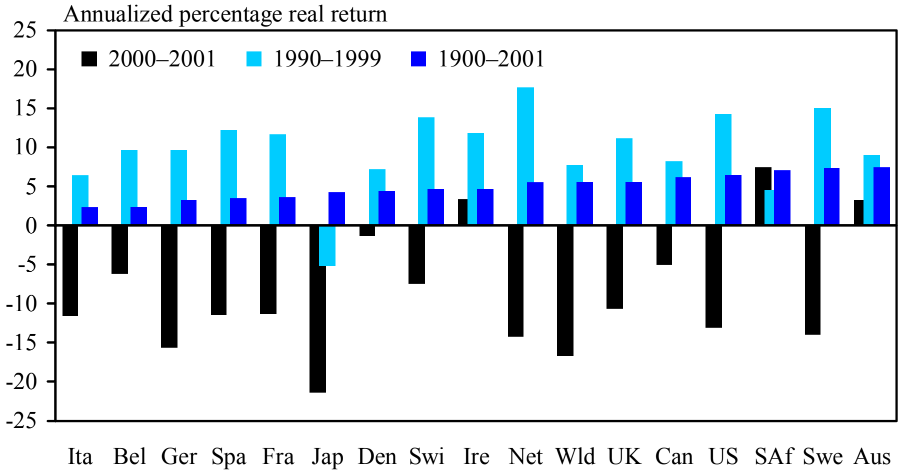
* This paper draws on, extends, and updates the research that underpinned our recent book, "*Triumph of the Optimists: 101 Years of Global Investment Returns*" (New Jersey: Princeton University Press, 2002). We are very grateful to ABN Amro for their extensive support and to our many international data contributors—too numerous to mention here, but all of whom are listed and cited in "Triumph". We are also grateful for the many helpful comments received from participants at numerous academic and practitioner seminars held around the world.

FIGURE 1
SHORT-TERM AND LONG-RUN REAL RETURNS ON EQUITIES AROUND THE WORLD*



* The country names listed in abbreviated form along the horizontal axis are (from left to right) Italy, Belgium, Germany, Spain, France, Japan, Denmark, Switzerland, Ireland, The Netherlands, the world (the weighted average of the sixteen individual countries), The United Kingdom, Canada, The United States, South Africa, Sweden, and Australia.

Yet it is dangerous to overreact to recent stock market performance. It would be wrong for investors to conclude that just because equities have delivered a low return since New Year 2000 that there has been either a substantial fall, or indeed rise, in the long-term expected equity premium.

Figure 1 shows how US equity returns compared with those in fifteen other countries and the world index. The black bars show annualized equity returns over 2000–01. In most countries, equities suffered negative returns, underperforming bonds everywhere except Ireland, and falling short of bill returns everywhere except Australia, Ireland, and South Africa. Estimating the expected risk premium from the performance of equities relative to bills or bonds over this period would clearly be nonsense. Investors cannot have required or expected a negative return for assuming risk. Instead, this was simply a very disappointing period for equities.

But while the opening years of the twenty-first century (fortunately) do not provide a basis for generalising about future returns, looking back at the previous decade only confuses the picture. Indeed, it would be equally misleading to estimate future risk premia from data for 1990–99. The light blue bars in Figure 1 show that over this period, equity returns (except in Japan and South Africa) were high. The 1990s was a golden age for stocks, and golden ages, by definition, recur infrequently.

To understand the risk premium—which is the principal objective of this paper—we need to examine periods that are much longer than one or two years, or even a decade. This is because stock markets are volatile, with much variation in year-to-year returns. In order to make inferences we thus need long time series that incorporate the bad times as well as the good. The dark blue bars in Figure 1 provide an insight into the perspective that longer periods of history can bring. These show real equity returns over the 102-year period from 1900–2001. Clearly, these 102-year returns are much less favourable than the returns during the 1990s, but equally, they contrast sharply with the disappointing returns over 2000–01.

Investors' judgements should thus be informed by the full extent of financial market history, and by looking not just at the United States, but at other countries as well.

Limitations of prior estimates of the risk premium

To be fair, financial economists do tend to measure the equity premium over quite long periods. Standard practice, however, draws heavily on the United States, with most textbooks citing only the US experience. By far the most widely cited US source prior to the end of the technology bubble was Ibbotson Associates[1], whose equity premium history starts in 1926. They estimated an annualized return on equities of 11.3 percent, and a risk-free return of 3.8 percent. This implied a geometric premium relative to bills of 7.3 percent (i.e., 1.113/1.038 = 1.073). References to other countries are few and far between, but a few textbooks also cite UK evidence. Before the publication of the research that underpins this paper, the most widely cited sources for the United Kingdom were the studies published by Barclays Capital and CSFB[2], which both started in 1919, and who published equity and risk-free returns of 12.2 and 5.5 percent, implying an annualized risk premium relative to bills of 6.4 percent.

In citing these estimates, financial economists are generally making the implicit assumption that provided the data are of sufficient quality, then the historical risk premium, measured over many decades, will provide an unbiased estimate of the future premium. Yet the twentieth century proved to be a period of remarkable growth in the US economy, and it seems probable that the outcome exceeded the expectations held in 1926 by US investors. Similar arguments apply to the United Kingdom, and the likely expectations of UK investors in 1919, but additionally, the UK evidence turned out to be based on a retrospectively constructed index whose composition, up to 1955, was tainted by survivor bias and narrow coverage.

In recent years, both practitioners and researchers have grown increasingly uneasy about these widely cited estimates, largely because they seem high. Apart from biases in index construction, the finger of suspicion has pointed mainly at success and survivorship bias. One influential study by Jorion and Goetzmann[3], for example, asserted, “the high equity premium obtained for US (and, by implication, UK) equities appears to be the exception rather than the rule” (parenthesis added). Recently, Zvi Bodie[4] argued that high US and UK premia are likely to be anomalous, and underlined the need for comparative international evidence. He pointed out that long-run studies are always of US or UK premia: "There were 36 active stock markets in 1900, so why do we only look at two? I can tell you—because many of the others don't have a 100-year history, for a variety of reasons." This paper helps fill this gap in our knowledge by providing a 102-year back-history of risk premia for sixteen of these markets.

NEW EVIDENCE

The new evidence on long-run risk premia presented in this paper is derived from a unique new database of long-run international returns. This comprises annual returns on stocks, bonds, bills, inflation, and currencies for sixteen countries from 1900–2001. The countries include the two main North American markets, namely, the United States and Canada, the United Kingdom, seven markets from what is now the Euro currency area, three other

1. See Ibbotson Associates, 2000, *Stocks, Bonds, Bills and Inflation Yearbook*, Chicago, Ibbotson Associates

2. Barclays Capital, 1999, *Equity-Gilt Study*, London: Barclays Capital; and Credit Suisse First Boston, 1999, *The CSFB Equity-Gilt Study*, London: Credit Suisse First Boston.

3. Jorion, P. and W. Goetzmann, “Global Stock Markets in the Twentieth Century”, *Journal of Finance*, Vol. 54, 1999, pp. 953-80.

4. Bodie, Z, “Longer time horizon ‘does not reduce risk’” *Financial Times*, 26 January 2002.

European markets, two Asia-Pacific markets, and one African market. Together, these countries made up 95 percent of the free float market capitalization of all world equities at start-2002, and we estimate that they comprised over 90 percent by value at the start of our period in 1900.

To compile this database, we assembled the best quality indices and returns data available for each national market from previous studies and other sources[5]. Where possible, we used data from peer-reviewed academic papers, although some studies were previously unpublished. To span the full period from 1900 onward, we typically linked more than one index series. For our own home market, the UK, we constructed our own indices, since hitherto there was no satisfactory record of long run returns. For the period since 1955, we used the London Business School Share Price Database to construct an index covering the entire UK equity market[6]. From 1900–55, we constructed an index of the performance of the largest 100 companies by a process of painstaking financial archaeology, collecting data from archives in the City of London. We also used archive data to construct indices for several other countries (e.g., Canada, Ireland, South Africa) for periods for which no data was previously available.

Unlike most previous long-term studies of global markets, all our investment returns include reinvested gross income as well as capital gains. Many early equity indices measure just capital gains, ignoring dividends, thereby introducing serious downward bias. Similarly, many early bond indices record just yields, ignoring price movements. Our database is thus more comprehensive and accurate than previous research, spans a longer period, and the common start-date of 1900 aids international comparisons. We can now set the US risk premia data alongside comparable 102-year risk premia series for fifteen other countries, and make international comparisons that help set the US experience in perspective.

Table 1 shows the historical equity risk premia for the sixteen countries over the 102-year period 1900–2001. We also display equity premia for the world, based on our world equity index. The latter comprises a sixteen-country, common-currency (here taken as US dollars) equity index in which each country is weighted by its start-year market capitalization or (in earlier years) its GDP[7]. The left-hand half of Table 1 shows equity premia measured relative to the return on treasury bills (or the nearest equivalent short-term instrument); the right-hand half shows premia calculated relative to the return on long-term government bonds. Since the world index is computed here from the perspective of a US (dollar) investor, the world equity risk premium relative to bills is calculated relative to the US risk free (i.e., treasury bill) rate. The world equity premium relative to bonds is calculated relative to a GDP-weighted, sixteen-country, common-currency (here taken as US dollars) world bond index.

In each half of the table we show three measures. These are, first, the geometric mean risk premium, namely, the annualized premium over the entire 102 years; second, the arithmetic mean of the 102 one-year premia; and third, the standard deviation of the 102 one-year premia. While the United States and the United Kingdom have indeed performed well, compared to other markets there is no indication that they are hugely out of line.

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5. Details of our data sources for all sixteen countries together with full citations are provided in Dimson, E, P R Marsh, and M Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, Princeton University Press, 2002.

6. Dimson, E and P R Marsh, "UK Financial Market Returns 1955-2000", *Journal of Business*, Vol. 74, pp. 1–31.

7. We use market capitalization weights from 1968 onward and GDP (gross domestic product) weights before then due to the lack of reliable comprehensive data on country capitalizations prior to that date.

TABLE 1
EQUITY RISK PREMIA AROUND THE WORLD 1900–2001

	Equity risk premia (percent per year)					
	Relative to bills			Relative to bonds		
Country	Geo-metric mean	Arith-metic mean	SD	Geo-metric mean	Arith-metic mean	SD
Australia	7.0	8.5	17.2	6.3	7.9	18.8
Belgium	2.7	5.0	23.5	2.8	4.7	20.7
Canada	4.4	5.7	16.7	4.2	5.7	17.9
Denmark	1.6	3.2	19.4	1.8	3.1	16.9
France	7.1	9.5	23.9	4.6	6.7	21.7
Germany*	4.6	10.0	35.3	6.3	9.6	28.5
Ireland	3.4	5.3	20.5	3.1	4.5	17.3
Italy	6.6	10.6	32.5	4.6	8.0	30.1
Japan	6.4	9.6	27.9	5.9	10.0	33.2
The Netherlands	4.8	6.8	22.3	4.4	6.4	21.5
South Africa	6.1	8.2	22.4	5.4	7.1	19.6
Spain	3.1	5.2	21.4	2.2	4.1	20.2
Sweden	5.3	7.4	21.9	4.9	7.1	22.1
Switzerland*	4.0	5.8	19.6	2.4	3.9	18.0
United Kingdom	4.5	6.2	19.9	4.2	5.5	16.7
United States	5.6	7.5	19.7	4.8	6.7	20.0
World	4.6	5.9	16.5	4.3	5.4	14.6

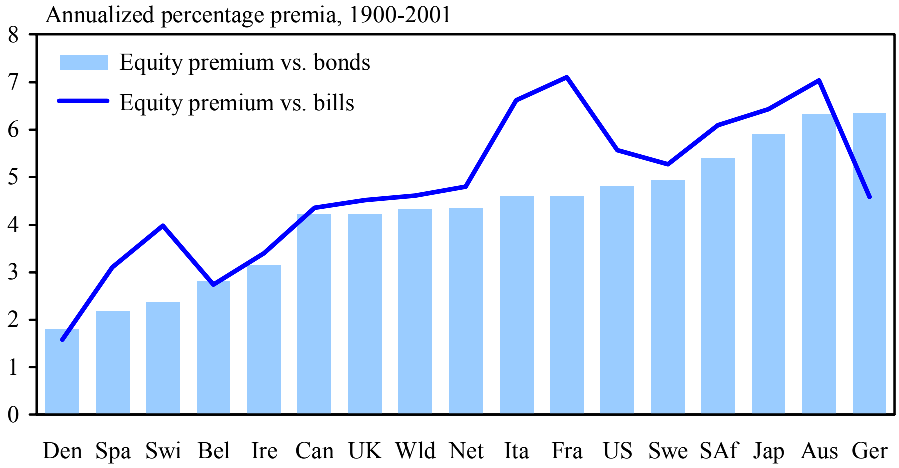
**Germany excludes 1922-23. Switzerland commences in 1911.*
Source: Dimson, Marsh, and Staunton, Triumph of the Optimists, Princeton University Press, 2002.

Over the entire 102-year period, the annualized equity risk premium, relative to bills, was 5.6 percent for the United States and 4.5 percent for the United Kingdom. Averaged across all sixteen countries, the risk premium relative to bills was 4.8 percent, while the risk premium on the world equity index was 4.6 percent. Relative to long bonds, the story is similar. The annualized US equity risk premium relative to bonds was 4.8 percent, and the corresponding figure for the United Kingdom was 4.2 percent. Across all sixteen countries, the risk premium relative to bonds averaged 4.3 percent, while for the world index it was also 4.3 percent.

The annualized equity risk premia are plotted in Figure 2. In this figure, countries are ranked by the equity premium relative to bonds, displayed as bars. The line-plot presents each country's risk premium relative to bills. It can be seen that the United States does indeed have a historical risk premium that is above the world average, but it is by no means the country with the largest recorded premium. The equity premium for the United Kingdom is closer to the worldwide average. While US and UK equities have performed well, both countries are towards the middle of the distribution of worldwide equity premia. Commentators have suggested that survivor bias may have given rise to equity premia for the United States and the United Kingdom that are unrepresentative. While legitimate, these concerns are somewhat overstated. Investors may not have been materially misled by a focus on the US and UK experiences. Rather, the critical factors are the period over which the risk premium is estimated, together with the quality of the index series.

FIGURE 2

WORLDWIDE ANNUALIZED EQUITY RISK PREMIA 1900–2001



Germany excludes 1922-23. Switzerland commences in 1911.
Source: Dimson, Marsh, and Staunton, Triumph of the Optimists, Princeton University Press, 2002.

Avoiding bias

There are noteworthy differences between the premia reported in this paper and those put forward, prior to publication of our research, by Ibbotson Associates in the United States, and by Barclays Capital and CSFB in the United Kingdom. Indeed, the premia estimated in this paper are around 1½ percent lower than those reported in these earlier studies. The differences arise from previous biases in index construction for the United Kingdom and, for both countries, from the choice of time frame, which in our case extends back to 1900[8]. We thus include the pre-1926 period for the United States (and pre-1919 for the United Kingdom) when returns were lower, partly due to events in the period leading up to, and including, World War I. Moreover, as noted above, prior perceptions about the risk premium have been dominated by the widely cited US estimates. Yet Table 1 and Figure 2 show that the premia for two-thirds of the other countries in our sample were lower than for the United States[9].

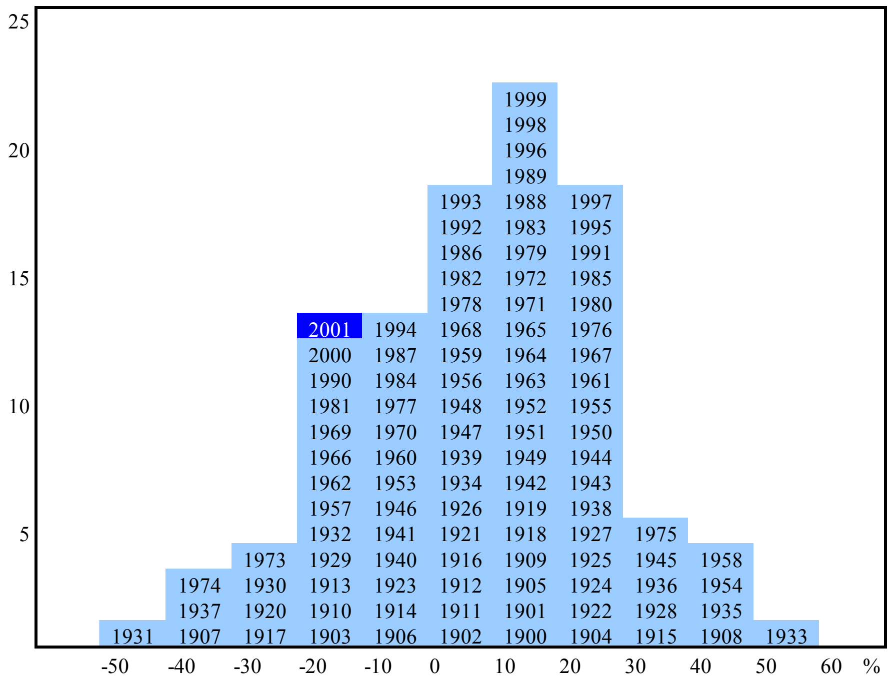
It is thus clear that the 102-year historical estimates of equity premia reported here are lower than was previously thought and other studies suggest. Even then, however, the historical record may overstate expectations. First, even if we have been successful in avoiding survivor bias within each index, we still focus on markets that survived, omitting countries such as Poland, Russia or China whose compound rate of return was –100 percent. Although these markets were relatively small in 1900[10], their omission probably leads to an overestimate of the

8. Interestingly, after publication of our research, Barclays Capital (but not CSFB) corrected their pre-1955 estimates of UK equity returns for bias and extended their index series back to 1900.

9. Table 1 shows that the annualized world equity risk premium relative to bills was 4.6 percent compared with 5.6 percent for the United States. Part of this difference, however, reflects the strength of the dollar over the period 1900–2001. The world risk premium is computed here from the world equity index expressed in dollars, in order to reflect the perspective of a US-based global investor. Since the currencies of most other countries depreciated against the dollar over the twentieth century, this lowers our estimate of the world equity risk premium relative to the (weighted) average of the local-currency based estimates for individual countries.

10. See Rajan, R and L Zingales, "The Great Reversals: The Politics of Financial Development in the 20th Century", Working paper No. 8178, Cambridge MA: National Bureau of Economic Research and Dimson, E, P R Marsh, and M Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, Princeton University Press, 2002.

FIGURE 3
HISTOGRAM OF US EQUITY RISK PREMIUM RELATIVE TO BILLS, 1900–2001



Source: Dimson, Marsh and Staunton, Triumph of the Optimists, Princeton University Press, 2002

worldwide risk premium.[11] Second, our premia are estimated relative to bills and bonds, which in a number of countries gave markedly negative real returns. Since these "risk-free" returns likely fell below investors' expectations, the corresponding equity premia are probably overstated.[12]

Although there is room for debate, we do not consider market survivorship to be the most important source of bias when inferring expected premia from the historical record. There are cogent arguments for suggesting that investors expected a lower premium than they actually received. However, this is more to do with a failure to fully anticipate improvements in business and investment conditions during the second half of the last century, an issue that we will return to below.

VARIATION IN RISK PREMIA OVER TIME

The historical equity premia shown in Figure 2 are the geometric means of 102 separate one-year premia that vary a great deal. In Figure 3 we show the year-by-year premia on US equities relative to bills. The lowest excess return was –45 percent in 1931, when equities returned –44 percent and treasury bills 1.1 percent; the highest was 57 percent in 1933, when equities gave 57.6 percent and bills 0.3 percent. Figure 3 shows that, for the United States,

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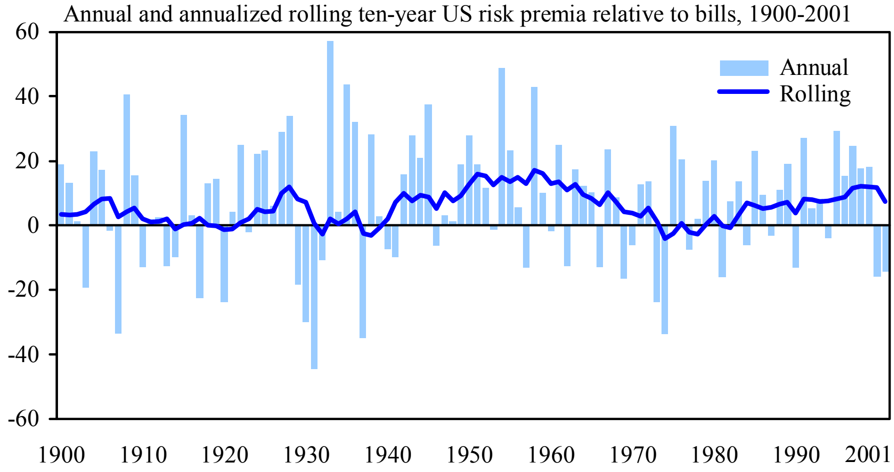
11. We say omitting non-surviving markets "probably" gives rise to overestimated risk premia because of the possibility that some defaulting countries have returns of –100 percent on bonds, while equities retain some residual value. For such countries, the ex post equity premium would be positive.

12. We again say low risk-free rates probably give rise to overstated risk premia because equity returns would presumably have been higher if economic conditions had not given rise to markedly negative real fixed-income returns. If economic conditions had been better, it is possible that the equity premium would then have been larger.

FIGURE 4

ROLLING AND ANNUAL TEN-YEAR US PREMIA RELATIVE TO BILLS, 1900–2001



Source: Dimson, Marsh and Staunton, Triumph of the Optimists, Princeton University Press, 2002

the distribution of annual excess returns is roughly symmetrical with a mean of 7.5 percent and a standard deviation of 19.7 percent. On average, therefore, US investors received a positive, and quite large, reward for exposure to equity market risk.

Because the range of excess returns encountered on a year-to-year basis is very broad, it can be misleading to label them "risk premia." As already noted, investors cannot have expected, let alone required, a negative risk premium from investing in equities, otherwise they would simply have avoided them. All the negative and many of the very low premia plotted in the histogram must therefore reflect nasty surprises. Equally, investors could not have required premia as high as 57 percent in 1933. Such numbers are implausible as a required reward for risk, and the high realizations must therefore reflect pleasant surprises. To avoid confusion, many writers choose not to refer to annual excess returns as "risk premia". They simply clarify that excess returns are ex post returns in excess of the risk free interest rate.

As we noted above, because one-year excess returns are so variable, we need to examine much longer periods, in the hope that good and bad luck might then cancel out. A common choice of time frame is a decade. In Figure 4, we show the US equity risk premium, measured over a sequence of rolling ten-year periods, superimposed on the annual returns since 1900.

Even over ten-year periods, the historical risk premium was sometimes negative, most recently in the 1970s and early 1980s. Again, since investors cannot have required a negative reward for risk, these must reflect unpleasant surprises. Figure 4 also reveals several cases of double-digit ten-year premia. These must have been pleasant surprises, as they are too high to reflect prior expectations. Clearly, a decade is still too short a period for good and bad luck to cancel out, and for drawing inferences about investors' expectations. Over a decade, like a single year, all we are plotting is the excess return that was realised over a period in the past.

Imprecise estimates

Prior to our research, studies for countries other than the United States and United Kingdom used the longest stock return series available, typically covering an interval of up to half a century. Sadly, even such a long research period does not yield an answer that is invariant to the choice of period. Taking the United Kingdom as an illustration, the arithmetic mean annual excess return for the first half of the twentieth century was only 3.1 percent, as compared to 9.2 percent from 1950 to date.

Even with a full century of data, market fluctuations have an impact. All we can state with confidence is what the excess return was in the past. This is why some writers restrict the term "risk premium" to denote the expected reward from equity investment. To avoid confusion, we make it clear when we are looking to the future by referring to the expected or "prospective" risk premium. When we measure the excess return over a period in the past we generally refer to this as the "historical" risk premium.

With 102 years of data, the potential inaccuracy in historical risk premia is high. The standard error measures this inaccuracy. It is approximately equal to one-tenth of the annual standard deviation of returns reported in Table 1. The standard error for the United States is 1.9 percent, and the range runs from 1.7 percent (Australia and Canada) to 3.5 percent (Germany). This means that while the US arithmetic mean premium (relative to bills) has a best estimate of 7.5 percent, we can be only two-thirds confident that the true mean lies within one standard error of this, namely within the range 7.5 ± 1.9 percent, or 5.6 to 9.4 percent. Similarly, there is a nineteen-out-of-twenty probability that the true mean lies within two standard errors, namely 7.5 ± 3.8 percent, or 3.7 to 11.3 percent. These high standard errors are why the longest possible series of stock market data should in general be used for estimating risk premia.

FROM THE PAST TO THE FUTURE

To estimate the equity risk premium to use in discounting future cash flows, we need the expected future risk premium, i.e., the arithmetic mean of the possible premia that may occur. Suppose the returns that may happen in the future are drawn from the same distribution as those that occurred in the past. If so, the expected risk premium is the arithmetic mean (or simple average) of the one-year historical premia. Whenever there is some variability in annual premia, the arithmetic mean will always exceed the geometric mean (or annualized) risk premium.[13]

In Figure 5, the full height of the bars shows the historical arithmetic mean premium relative to bills for each country. The US equity premium is 7.5 percent, while the world equity risk premium is 5.9 percent. The arithmetic mean premia are noticeably higher than the geometric mean premia shown by the light blue portion of each bar. They are at their largest (in both absolute terms and relative to the geometric mean) for the countries that experienced the greatest volatility of returns over the last century (see Table 1).

In looking to the future, let us assume for the moment that investors in each country expect the same annualized (geometric mean) risk premium as they have received in the past. The bar and line plots in Figure 5 can then be interpreted as forecasts of the prospective arithmetic risk premia under alternative assumptions about future volatility. If there were no volatility in future annual returns, the expected arithmetic risk premia would be equal to their (historical)

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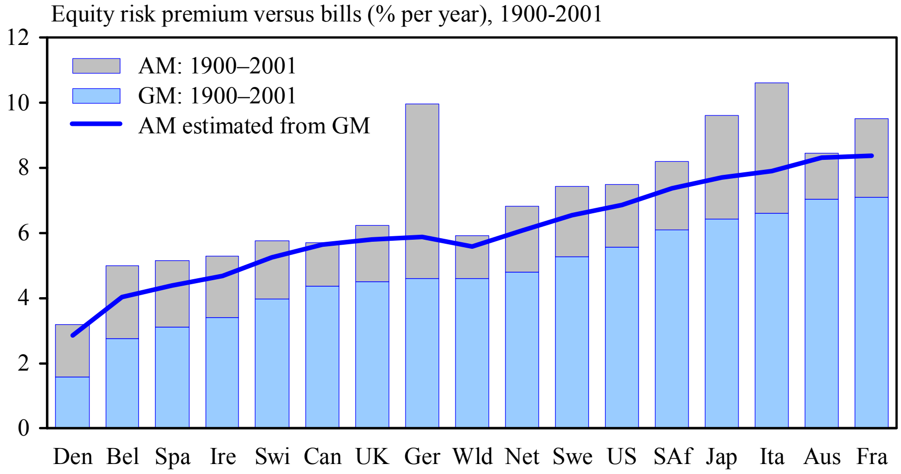
13. For example, the arithmetic mean of two equally likely returns of +25 percent and –20 percent is (+25 – 20)/2 = 2½ percent, while their geometric mean is zero since (1 + 25/100) x (1 – 20/100) – 1 = 0.

FIGURE 5
ARITHMETIC MEAN EQUITY RISK PREMIA RELATIVE TO BILLS, 1900–2001



Source: Dimson, Marsh and Staunton, Triumph of the Optimists, Princeton University Press, 2002

geometric mean premia shown by the height of the light blue portion of the bars in Figure 5. On the other hand, if future volatility were equal to the long-term historical volatility, the expected risk premia would be equal to the historical arithmetic mean risk premia, shown by the full height of the bars. However, the long-term historical standard deviation is a poor predictor of future volatility, especially since some sources of extreme volatility (such as hyperinflation) are unlikely to recur. We therefore need estimates of expected future risk premia that are conditional on current predictions for market volatility.

When returns are distributed lognormally, the geometric and arithmetic means are linked by the standard deviation (or volatility) of returns. We therefore estimate the expected future arithmetic mean premium for each country, replacing the historical difference between the arithmetic and geometric means with a difference based on contemporary risk estimates. For expositional simplicity, even though the volatility of one stock market is not in reality the same as another, we assume a current volatility level for all sixteen national markets of 16 percent, and for the world index of 14 percent. The resulting estimates of the arithmetic mean premia relative to bills are shown by the dark blue line-plot in Figure 5.

For those wishing to forecast future arithmetic mean risk premia by extrapolating from the long-run historical annualized premia, the premia illustrated by the line plot in Figure 5 are the ones to use. The historical equity risk premium, adjusted to current levels of market volatility, is estimated as 6.8 percent for the United States, and 5.6 percent for the world index.

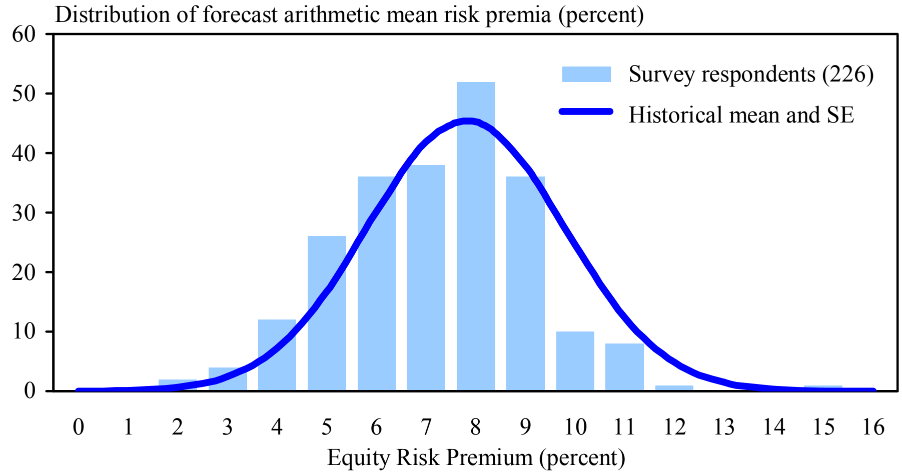
THE EXPERTS' CONSENSUS

In refocusing on the expected future risk premium, however, we must do more than extrapolate from the past. The question of what equity premium we can expect has, for years, been a source of controversy. In late 1998 Ivo Welch studied the opinions of 226 financial economists who were asked to forecast the thirty-year arithmetic mean equity risk premium [14].

14. Welch, I, "Views of Financial Economists on the Equity Premium and Other Issues," *Journal of Business*, Vol. 73, 2000, pp. 501-537.

FIGURE 6

FINANCIAL ECONOMISTS' RISK PREMIUM FORECASTS AND MARKET HISTORY



The bars in Figure 6 show the distribution of the responses. The mean forecast was 7.1 percent; the median was 7.0 percent, and the range ran from 1 to 15 percent.

While the bars in Figure 6 show the distribution of survey responses, the curved line represents the normal distribution based on the mean over approximately a century and the associated standard error for the US equity risk premium. The spread in both distributions indicates that the uncertainty across financial experts about the risk premium is as large as the uncertainty that arises from statistical analysis of historical returns.

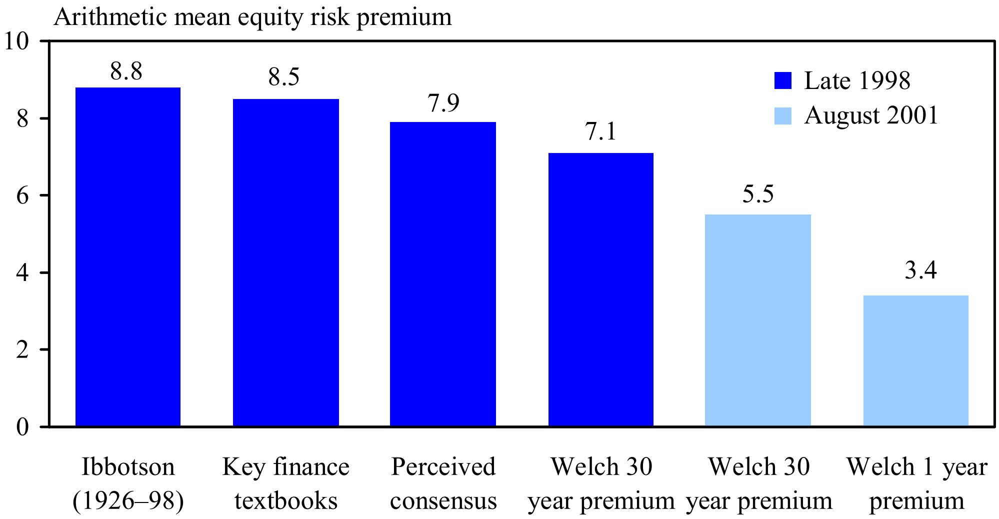
Most respondents to the Welch survey would have regarded the Ibbotson Associates yearbook as the definitive study of the historical US risk premium. The first bar of Figure 7 shows that the 1926-98 arithmetic risk premium computed from Ibbotson data was 8.8 percent per year. The second bar shows that the key finance textbooks were on average suggesting a premium of 8.5 percent, a little below the Ibbotson figure. The textbook authors may have based their views on earlier, slightly lower, Ibbotson estimates, or else they were shading the Ibbotson estimates downward. The Welch survey mean is in turn lower than the textbook figure, but since respondents claimed to lower their forecasts when the equity market rises, this difference may be attributed to the market's strong performance in the 1990s. Interestingly, the third and fourth bars of Figure 7 show that the survey respondents also perceived the profession's consensus to be higher than it really was. That is, they thought the mean was around 0.8 percent higher than the 7.1 percent average revealed in the survey.

These survey and textbook figures represent what was being taught at the end of the 1990s in the world's leading business schools and economics departments in the United States and around the world. As such, these estimates were also widely used by investors, finance professionals, corporate executives, regulators, lawyers and consultants. Their influence extended from the classroom to the dealing room, to the boardroom, and to the courtroom.

New opinions

Whether Welch's survey mean of 7.1 percent was appropriate is another matter. A large number of respondents were calibrating their forecasts relative to the longest-run historical benchmark available from Ibbotson, and then shading the historical number downward based on subjective factors, including their judgement of the impact of strong market performance in the late 1990s. By 2001, longer-term estimates of the US arithmetic mean equity premium

FIGURE 7
ESTIMATED ARITHMETIC RISK PREMIA RELATIVE TO BILLS, 1998 AND 2001



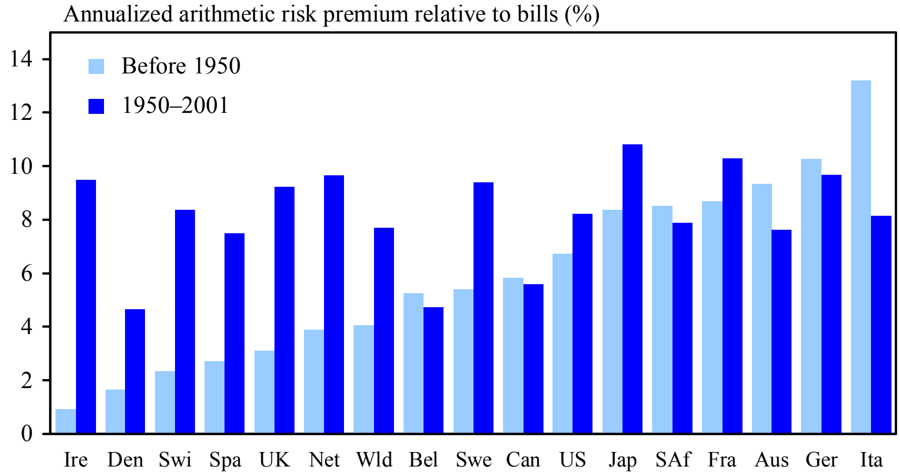
were gaining publicity. Including pre-1926 data, and extending the period through the start of the new millennium, the 1900-2000 mean premium was 1.1 percent lower than the Ibbotson estimate on the left-hand side of Figure 7. At the same time, survey respondents who sought to predict a premium below the consensus might have been encouraged by publication of the survey to further reduce their estimates.

In August 2001, Welch updated his earlier survey, receiving responses from 510 finance and economics professors[15]. He found that respondents to the follow-up questionnaire had revised downward their estimates of the long-term arithmetic mean risk premium by an average of 1.6 percent. Over a thirty-year horizon they now estimated an equity premium averaging 5.5 percent, and over a one-year horizon, an equity premium averaging 3.4 percent (see Figure 7). The mean premia were the same for those who had previously participated in the earlier survey and those who were taking part for the first time. Although respondents to the earlier survey had indicated that, on average, a bear market would raise their equity premium forecast, Welch (2001) reports that "This is in contrast with the observed findings: it appears as if the recent bear market correlates with lower equity premium forecasts, not higher equity premium forecasts".

Predictions of the long-term equity premium should not be so sensitive to short-term stock market fluctuations, especially in the direction and magnitude revealed by Welch's follow-up survey in 2001. While it is possible that one-year required rates of return fluctuate markedly, it is unlikely that thirty-year expectations can be so volatile. The changing consensus may, however, reflect the new approaches to estimating the premium and /or new facts about long-term stock market performance, such as evidence that other countries have typically had historical premia that were lower than the United States.

15. Welch, I, "The Equity Premium Consensus Forecast Revisited," Working paper, Yale School of Management, September 2001.

FIGURE 8
PREMIA RELATIVE TO BILLS, FIRST 50 YEARS VERSUS THE NEXT 52 YEARS



Germany excludes 1922-23. Switzerland commences in 1911.
Source: Dimson, Marsh and Staunton, Triumph of the Optimists, Princeton University Press, 2002

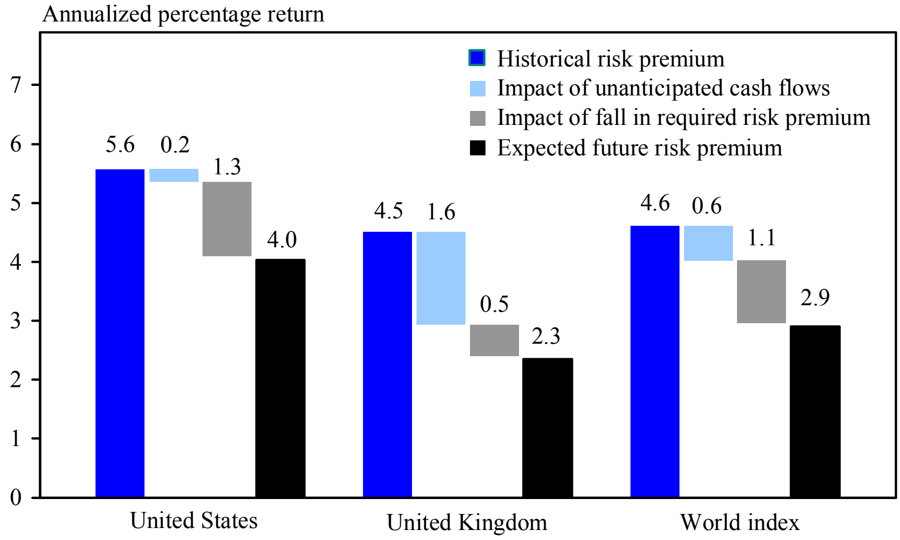
REVISITING HISTORY

The wide dispersion of estimates, together with the dramatic decline in the consensus premium between 1998 and 2001, reinforces the need to better understand the historical record. However, since history may have been kind to (or harsh on) stock market investors, there are coherent arguments for going beyond raw historical estimates. First, the whole idea of using the achieved risk premium to forecast the required risk premium depends on having a long enough period to iron out good and bad luck, yet as we noted earlier, even with 102 years of data our estimates are imprecise. Second, the expected equity risk premium could for good reasons vary over time. Third, we must take account of the fact that stock market outcomes are influenced by many factors, some of which (like removal of trade barriers) may be non-repeatable, which implies projections for the premium that deviate from the past.

A comparison between the first and second halves of our 102-year period makes the point. Over the first half of the twentieth century, the arithmetic average world equity risk premium relative to bills was 4.1 percent, whereas over the period 1950–2001, it was 7.7 percent. Figure 8 shows that most of the sixteen countries had lower mean premia in the first half-century, with Australia, Italy, Belgium, and South Africa being the exceptions. The sixteen-country (unweighted) mean of the arithmetic risk premia in the first half of the twentieth century was 6.0 percent, versus 8.2 percent in the next fifty-two years. The pattern for the equity premium relative to bonds (not shown in Figure 8) is similar: a pre-1950 mean of 5.5 percent as compared to 7.1 percent over the following fifty-two years.

The large risk premia achieved during the second half of the twentieth century are attributable to three factors. First, there was unprecedented growth in productivity and efficiency, accelerating technological change, and enhancements to the quality of management and corporate governance. As Europe, North America, and the Asia-Pacific region emerged from the turmoil of the Second World War, expectations for improvement were limited to what could be imagined. Reality almost certainly exceeded investors' expectations. Corporate cash flows grew faster than investors anticipated, and this higher growth is now known to the market and built into higher stock prices.

FIGURE 9
INFERRING EXPECTATIONS FROM THE HISTORICAL PREMIUM



Source: Dimson, Marsh and Staunton, Triumph of the Optimists, Princeton University Press, 2002

Second, stock prices have also risen because of a fall in the required rate of return due to diminished business and investment risk. Business risk diminished as the economic and political lessons of the twentieth century were learned, international trade flows increased, and the Cold War ended. Investment risk diminished over time as investors gained the benefits of diversification, both domestically (through a wider range of quoted securities and industries[16], and through intermediaries such as mutual funds) and internationally (with the disappearance of impediments to foreign investment). Diversification allows investors to lower their risk exposure without detriment to expected return. Finally, transaction and monitoring costs are also lower now than a century ago. Factors such as these, which led to a reduction in the required risk premium, have contributed further to the upward re-rating of stock prices.

To convert from a pure historical estimate of the risk premium into a forward-looking projection, we need to reverse-engineer the factors that drove up stock markets over the last 102 years. The simplest idea would be to infer the impact on returns of the historical changes in dividend yield. But we can go beyond this, as shown in Figure 9. The left-hand panel of Figure 9 relates to the US equity market, the centre panel to the UK market, and the right-hand panel to the world market. Within each panel, the first bar portrays the historical annualized risk premium of the equity market. This includes the contribution from unanticipated growth in cash flows and the gain from falls in the required risk premium. We therefore deduct the impact of these two factors. What remains in the right-hand bar of each panel is an estimate of the prospective risk premium demanded by investors as compensation for the risks of equity investment. We explain below how we quantify the deductions in the two centre bars of each panel, but the key qualitative point is that the prospective risk premium is lower than the raw historical risk premium.

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16. At the start of our research period in 1900, US domestic investors would have found it much harder than today to construct a well-diversified portfolio. At the start of 1900, there were just 123 stocks listed on the New York Stock Exchange, and a single industry, railroads, accounted for 63 percent of their total market value. See Chapter 2, Dimson, E, P R Marsh, and M Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, Princeton University Press, 2002.

Unanticipated growth

To apply this framework, we need some notion of when cash flows (proxied here by equity dividends) have exceeded or fallen short of expectations. A simple approach that is commonly used today for forecasting the long-run dividend growth rate is to extrapolate from previous long-term dividend growth. The long-term real dividend growth rate is then used to make a naive projection of future real growth. That is, we estimate the product of *1 + Year 1 annual growth* multiplied by *1 + Year 2 annual growth* and so on to year *n*. We then compute the n^{th} root of this product, which is equal to *1 + Projected growth*. To summarize, we calculate the annualized real dividend growth rate to each year-end, over periods that start in 1900.

We assume that at every December 31st, investors compare the year's real dividend growth to the real growth rate that would have been projected as at January 1st of that year. The difference is defined as *1 + Annual dividend growth* divided by *1 + Projected growth*, minus *1*. This error in projecting dividend growth may be thought of as the unanticipated growth rate in dividends. The unanticipated changes in dividend growth are compounded together to produce an estimate of their annualized impact over the last century. This is clearly a rather ad hoc measure of unanticipated real dividend growth, but it suffices to illustrate the general idea. Defined this way, Figure 9 shows that the stock price impact of unanticipated dividend growth over the period from 1900 to 2001 is 0.2 percent per year for the United States, 1.6 percent per year in the United Kingdom, and 0.6 percent per year for the world equity market.

Since 1900, there has also been a dramatic change in the valuation basis for equity markets. The price/dividend ratio (the reciprocal of the dividend yield) at the start of 1900 was twenty-three in both the United States and the United Kingdom, but by the start of 2002, the US ratio had risen to eighty-one and the UK ratio to thirty-nine. Undoubtedly, this change is in part a reflection of expected future growth in real dividends, so we could in principle decompose the impact of this valuation change into both an element that reflects changes in required rates of return, and an element that reflects enhanced growth expectations.

To keep things simple, we assume that the increase in the price/dividend ratio is attributable solely to a long-term fall in the required risk premium for equity investment. Given this assumption, Figure 9 shows that the stock price impact of the fall in the required risk premium since 1900 is 1.6 percent per year in the United States and 0.5 percent per year in the United Kingdom. This, together with the impact of unanticipated dividend growth, must be deducted from the historical risk premium.

To estimate the expected future risk premia, we must deduct the impact of both unanticipated cash flows and the fall in the required risk premium from our historical premia. The first of these adjustments can be thought of as the impact of good luck, while the second can be viewed as the effect of re-rating. Figure 9 shows quite large differences in the relative importance of these factors between the United States and the United Kingdom. In particular, for the US market, good luck appears to have had a smaller impact, and re-rating a larger influence. This arises partly from our using dividends as a proxy for unexpected cash flows and changes in the dividend price ratio as a proxy for re-rating. In the United States, the rapid growth of stock repurchases and the trend toward "disappearing dividends"[17] makes it harder

17. See Fama, E. F. and K. R. French, "Disappearing Dividends: Changing Firm Characteristics or Lower Propensity to Pay", *Journal of Financial Economics*, Vol. 60, 2001, pp.3-43.

to disentangle these effects. The United States is the outlier among our sixteen countries[18], and in judging the relative contribution of unanticipated cash flows versus the impact of the fall in the required risk premium, the UK pattern may be more informative (see Figure 9).

The net effect of deducting the two adjustments from the historical risk premia is shown in the final bar of each of the three panels in Figure 9. These indicate an expected future geometric risk premium of 4.0 percent for the United States, 2.3 percent for the United Kingdom, and 2.9 percent for the world equity market. Our estimates for the United States are similar to those obtained recently by Fama and French using a related approach[19]. Also based on dividend yields and dividend growth estimates, Fama and French use the Gordon model to compute the US equity premium from 1872–1999. They find a premium of 3.8 percent before 1949, and a premium of 3.4 percent for the subsequent period. They argue that the difference between these estimates and the larger ex post risk premium based on historical realized returns is attributable to a reduction since 1949 in investors' required rate of return.

EXPECTED RISK PREMIA

If they are to be used as prospective risk premia, our annualized figures need to be converted into arithmetic means, as explained earlier. Using a projected standard deviation for US and UK equities of 16 percent, the prospective arithmetic risk premia for the United States is 5.3 percent, while the premium for the United Kingdom is 3.6 percent. Using a slightly lower standard deviation for the world index of 14 percent, the prospective arithmetic risk premium for the world index is 3.9 percent. Whichever country one focuses on, our forward-looking predictions for the equity risk premium are lower than the historically based projections reviewed earlier.

A literal interpretation of historical averages might suggest that France has a higher equity risk premium, while Denmark's is lower. While there are obviously differences in risk between markets, this is unlikely to account for cross-sectional differences in historical premia. Indeed, much of the cross-country variation in historical equity premia is attributable to country-specific historical events that will not recur. When making future projections, there is a strong case, particularly given the increasingly international nature of capital markets, for taking a global rather than a country-by-country approach to determining the prospective equity risk premium.

However, just as there must be some true differences across countries in their riskiness, there must also be variation over time in the levels of stock market risk. It is well known that stock market volatility wanders over time, and it is likely that the "price" of risk—namely the risk premium—also fluctuates over time. In the days following September 11, 2001 for example, financial market risk was high, and it is likely that the equity premium demanded by investors was also high. This depressed the market. If the terror had escalated further, the market may have collapsed; but Armageddon did not arrive and the market bounced back.

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18. Compared with the United States, stock repurchases have been far less prevalent in the other countries. In Europe, the United Kingdom has the highest level of buybacks, but even UK repurchases are small compared with the United States. See section 11.6 of Dimson, E, P R Marsh, and M Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, Princeton University Press, 2002.

19. Fama, E. F. and K. R. French, "The Equity Premium", *Journal of Finance*, Vol. 57, 2002, pp.637-59.

There were similar considerations a generation earlier during the Cuban missile crisis—another Armageddon that was averted. Clearly, at such times risk premia are above average. However, it is difficult to predict premia from the rolling ten-year averages depicted earlier in Figure 4. Indeed, it is difficult to infer expected premia from any analysis of historical excess returns. It may be better to use a "normal" equity premium most of the time, and to deviate from this prediction only when there are compelling economic reasons to suppose expected premia are unusually high or low.

CONCLUSION

The equity premium is the difference between the return on risky stocks and the return on safe bonds. The equity risk premium is central to corporate finance and investment. It is often described as the most important number in finance. Yet it is not clear how big the equity premium has been in the past, or how large it is today.

This paper has presented new evidence on the historical risk premium for sixteen countries over 102 years. Our estimates are lower than frequently quoted historical averages such as the Ibbotson Associates' figures for the United States and the earlier Barclays Capital and CSFB studies for the United Kingdom. The differences arise from previous bias in index construction for the United Kingdom, and, for both countries, from our choice of a longer time frame from 1900–2001, which incorporates the earlier part of the twentieth century, as well as the opening years of the new millennium. In addition, our global focus results in somewhat lower risk premia than hitherto assumed, since prior views have been heavily influenced by the experience of the United States, yet we find that the US risk premium has been somewhat higher than the average for the other fifteen countries.

The historical equity premium is often presented in the form of an annualized rate of return, which summarizes past performance in one number. For the future, what is required is the arithmetic mean of the distribution of equity premia, which is larger than the geometric mean. For markets that have been particularly volatile, the arithmetic mean of past equity premia may exceed the geometric mean premium by several percentage points.

In forecasting the future arithmetic mean premium, investors or companies who believe they can expect the same annualized risk premium as they have received in the past still need to adjust for the differences between historical market volatility and the volatility that we might anticipate today. More fundamentally, however, we have argued that past returns have been flattered by the impact of good luck and re-rating. Since the middle of the last century, equity cash flows almost certainly exceeded expectations, and the required rate of return doubtless fell as investment risk declined and the scope for diversification increased. Stock markets rose for reasons that are unlikely to be repeated. This means that when seeking forecasts for the future, historical risk premia should be adjusted downward for the impact of these factors.

We have illustrated one approach that can be used to make such adjustments. The result is a set of forward-looking, geometric mean risk premia for the United States, United Kingdom and for the world all falling within a range of around 2½ to 4 percent, and a corresponding set of arithmetic mean risk premia falling in a range of around 3½ to 5¼ percent. These estimates are not only far lower than the historical premia quoted in most textbooks, but they are also lower than those cited in surveys of finance academics.

Attachment 5.19

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 5.20

The Risk Premium Approach to Measuring a Utility's Cost of Equity

Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson

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■ In the mid-1960s, Myron Gordon and others began applying the theory of finance to help estimate utilities' costs of capital. Previously, the standard approach in cost of equity studies was the "comparable earnings method," which involved selecting a sample of unregulated companies whose investment risk was judged to be comparable to that of the utility in question, calculating the average return on book equity (ROE) of these sample companies, and setting the utility's service rates at a level that would permit the utility to achieve the same ROE as comparable companies. This procedure has now been thoroughly discredited (see Robichek [15]), and it has been replaced by three market-oriented (as opposed to accounting-oriented) approaches: (i) the DCF method, (ii) the bond-yield-plus-risk-premium method, and (iii) the CAPM, which is a specific version of the generalized bond-yield-plus-risk-premium approach.

Our purpose in this paper is to discuss the risk-premium approach, including the market risk premium that is used in the CAPM. First, we critique the various procedures that have been used in the past to estimate risk premiums. Second, we present some data on estimated risk premiums since 1965. Third, we examine the relationship between equity risk premiums and the level of interest rates, because it is important, for purposes of estimating the cost of capital, to know just how stable the relationship between risk premiums and interest rates is over time. If stability exists, then one can estimate the cost of equity at any point in time as a function of interest rates as reported in *The Wall Street Journal*, the *Federal Reserve Bulletin*, or some similar source.[1] Fourth, while we do not discuss the CAPM directly, our analysis does have some important implications for selecting a market risk premium for use in that model. Our focus is on utilities, but the methodology is applicable to the estimation of the cost of

[1]For example, the Federal Energy Regulatory Commission's Staff recently proposed that a risk premium be estimated every two years and that, between estimation dates, the last-determined risk premium be added to the current yield on ten-year Treasury bonds to obtain an estimate of the cost of equity to an average utility (Docket RM 80-36). Subsequently, the FCC made a similar proposal ("Notice of Proposed Rulemaking," August 13, 1984, Docket No. 84-800). Obviously, the validity of such procedures depends on (i) the accuracy of the risk premium estimate and (ii) the stability of the relationship between risk premiums and interest rates. Both proposals are still under review.

equity for any publicly traded firm, and also for non-traded firms for which an appropriate risk class can be assessed, including divisions of publicly traded corporations.[2]

Alternative Procedures for Estimating Risk Premiums

In a review of both rate cases and the academic literature, we have identified three basic methods for estimating equity risk premiums: (i) the *ex post*, or historic, yield spread method; (ii) the survey method; and (iii) an *ex ante* yield spread method based on DCF analysis.[3] In this section, we briefly review these three methods.

Historic Risk Premiums

A number of researchers, most notably Ibbotson and Sinquefield [12], have calculated historic holding period returns on different securities and then estimated risk premiums as follows:

$$\text{Historic Risk Premium} = \begin{pmatrix}\text{Average of the}\\ \text{annual returns on}\\ \text{a stock index for}\\ \text{a particular}\\ \text{past period}\end{pmatrix} - \begin{pmatrix}\text{Average of the}\\ \text{annual returns on}\\ \text{a bond index for}\\ \text{the same}\\ \text{past period}\end{pmatrix}. \quad (1)$$

Ibbotson and Sinquefield (I&S) calculated both arithmetic and geometric average returns, but most of their risk-premium discussion was in terms of the geometric averages. Also, they used both corporate and Treasury bond indices, as well as a T-bill index, and they analyzed all possible holding periods since 1926. The I&S study has been employed in numerous rate cases in two ways: (i) directly, where the I&S historic risk premium is added to a company's bond yield to obtain an estimate of its cost of equity, and (ii) indirectly, where I&S data are used to estimate the market risk premium in CAPM studies.

There are both conceptual and measurement problems with using I&S data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed, evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet they can result in significant differences in the final outcome. These measurement problems are common to most forecasts based on time series data.

The Survey Approach

One obvious way to estimate equity risk premiums is to poll investors. Charles Benore [1], the senior utility analyst for Paine Webber Mitchell Hutchins, a leading institutional brokerage house, conducts such a survey of major institutional investors annually. His 1983 results are reported in Exhibit 1.

Exhibit 1. Results of Risk Premium Survey, 1983*

Assuming a double A, long-term utility bond currently yields 12½%, the common stock for the same company would be fairly priced relative to the bond if its expected return was as follows:

Total Return	Indicated Risk Premium (basis points)	Percent of Respondents
over 20½%	over 800	
20½%	800	
19½%	700	
18½%	600	10%
17½%	500	8%
16½%	400	29%
15½%	300	35%
14½%	200	16%
13½%	100	0%
under 13½%	under 100	1%
Weighted average	358	100%

*Benore's questionnaire included the first two columns, while his third column provided a space for the respondents to indicate which risk premium they thought applied. We summarized Benore's responses in the frequency distribution given in Column 3. Also, in his questionnaire each year, Benore adjusts the double A bond yield and the total return (Column 1) to reflect current market conditions. Both the question above and the responses to it were taken from the survey conducted in April 1983.

[2]The FCC is particularly interested in risk-premium methodologies, because (i) only eighteen of the 1,400 telephone companies it regulates have publicly-traded stock, and hence offer the possibility of DCF analysis, and (ii) most of the publicly-traded telephone companies have both regulated and unregulated assets, so a corporate DCF cost might not be applicable to the regulated units of the companies.

[3]In rate cases, some witnesses also have calculated the differential between the yield to maturity (YTM) of a company's bonds and its concurrent ROE, and then called this differential a risk premium. In general, this procedure is unsound, because the YTM on a bond is a *future expected* return on the bond's *market value*, while the ROE is the *past realized* return on the stock's *book value*. Thus, comparing YTMs and ROEs is like comparing apples and oranges.

Benore's results, as measured by the average risk premiums, have varied over the years as follows:

Year	Average RP (basis points)
1978	491
1979	475
1980	423
1981	349
1982	275
1983	358

The survey approach is conceptually sound in that it attempts to measure investors' expectations regarding risk premiums, and the Benore data also seem to be carefully collected and processed. Therefore, the Benore studies do provide one useful basis for estimating risk premiums. However, as with most survey results, the possibility of biased responses and/or biased sampling always exists. For example, if the responding institutions are owners of utility stocks (and many of them are), and if the respondents think that the survey results might be used in a rate case, then they might bias upward their responses to help utilities obtain higher authorized returns. Also, Benore surveys large institutional investors, whereas a high percentage of utility stocks are owned by individuals rather than institutions, so there is a question as to whether his reported risk premiums are really based on the expectations of the "representative" investor. Finally, from a pragmatic standpoint, there is a question as to how to use the Benore data for utilities that are not rated AA. The Benore premiums can be applied as an add-on to the own-company bond yields of any given utility only if it can be assumed that the premiums are constant across bond rating classes. *A priori*, there is no reason to believe that the premiums will be constant.

DCF-Based *Ex Ante* Risk Premiums

In a number of studies, the DCF model has been used to estimate the *ex ante* market risk premium, RP_M. Here, one estimates the average expected future return on equity for a group of stocks, k_M, and then subtracts the concurrent risk-free rate, R_F, as proxied by the yield to maturity on either corporate or Treasury securities:[4]

$$RP_M = k_M - R_F. \qquad (2)$$

Conceptually, this procedure is exactly like the I&S approach except that one makes direct estimates of future expected returns on stocks and bonds rather than assuming that investors expect future returns to mirror past returns.

The most difficult task, of course, is to obtain a valid estimate of k_M, the expected rate of return on the market. Several studies have attempted to estimate DCF risk premiums for the utility industry and for other stock market indices. Two of these are summarized next.

Vandell and Kester. In a recently published monograph, Vandell and Kester [18] estimated *ex ante* risk premiums for the period from 1944 to 1978. R_F was measured both by the yield on 90-day T-bills and by the yield on the Standard and Poor's AA Utility Bond Index. They measured k_M as the average expected return on the S&P's 500 Index, with the expected return on individual securities estimated as follows:

$$k_i = \left(\frac{D_1}{P_0}\right)_i + g_i, \qquad (3)$$

where,

D_1 = dividend per share expected over the next twelve months,
P_0 = current stock price,
g = estimated long-term constant growth rate, and
i = the i^{th} stock.

To estimate g_i, Vandell and Kester developed fifteen forecasting models based on both exponential smoothing and trend-line forecasts of earnings and dividends, and they used historic data over several estimating horizons. Vandell and Kester themselves acknowledge that, like the Ibbotson-Sinquefield premiums, their analysis is subject to potential errors associated with trying to estimate expected future growth purely from past data. We shall have more to say about this point later.

[4]In this analysis, most people have used yields on long-term bonds rather than short-term money market instruments. It is recognized that long-term bonds, even Treasury bonds, are not risk free, so an RP_M based on these debt instruments is smaller than it would be if there were some better proxy to the long-term riskless rate. People have attempted to use the T-bill rate for R_F, but the T-bill rate embodies a different average inflation premium than stocks, and it is subject to random fluctuations caused by monetary policy, international currency flows, and other factors. Thus, many people believe that for cost of capital purposes, R_F should be based on long-term securities.

We did test to see how debt maturities would affect our calculated risk premiums. If a short-term rate such as the 30-day T-bill rate is used, measured risk premiums jump around widely and, so far as we could tell, randomly. The choice of a maturity in the 10- to 30-year range has little effect, as the yield curve is generally fairly flat in that range.

Malkiel. Malkiel [14] estimated equity risk premiums for the Dow Jones Industrials using the DCF model. Recognizing that the constant dividend growth assumption may not be valid, Malkiel used a nonconstant version of the DCF model. Also, rather than rely exclusively on historic data, he based his growth rates on Value Line's five-year earnings growth forecasts plus the assumption that each company's growth rate would, after an initial five-year period, move toward a long-run real national growth rate of four percent. He also used ten-year maturity government bonds as a proxy for the riskless rate. Malkiel reported that he tested the sensitivity of his results against a number of different types of growth rates, but, in his words, "The results are remarkably robust, and the estimated risk premiums are all very similar." Malkiel's is, to the best of our knowledge, the first risk-premium study that uses analysts' forecasts. A discussion of analysts' forecasts follows.

Security Analysts' Growth Forecasts

Ex ante DCF risk premium estimates can be based either on expected growth rates developed from time series data, such as Vandell and Kester used, or on analysts' forecasts, such as Malkiel used. Although there is nothing inherently wrong with time series-based growth rates, an increasing body of evidence suggests that primary reliance should be placed on analysts' growth rates. First, we note that the observed market price of a stock reflects the consensus view of investors regarding its future growth. Second, we know that most large brokerage houses, the larger institutional investors, and many investment advisory organizations employ security analysts who forecast future EPS and DPS, and, to the extent that investors rely on analysts' forecasts, the consensus of analysts' forecasts is embodied in market prices. Third, there have been literally dozens of academic research papers dealing with the accuracy of analysts' forecasts, as well as with the extent to which investors actually use them. For example, Cragg and Malkiel [7] and Brown and Rozeff [5] determined that security analysts' forecasts are more relevant in valuing common stocks and estimating the cost of capital than are forecasts based solely on historic time series. Stanley, Lewellen, and Schlarbaum [16] and Linke [13] investigated the importance of analysts' forecasts and recommendations to the investment decisions of individual and institutional investors. Both studies indicate that investors rely heavily on analysts' reports and incorporate analysts' forecast information in the formation of their expectations about stock returns. A representative listing of other work supporting the use of analysts' forecasts is included in the References section. Thus, evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts. Accordingly, we based our cost of equity, and hence risk premium estimates, on analysts' forecast data.[5]

Risk Premium Estimates

For purposes of estimating the cost of capital using the risk premium approach, it is necessary either that the risk premiums be time-invariant or that there exists a predictable relationship between risk premiums and interest rates. If the premiums are constant over time, then the constant premium could be added to the prevailing interest rate. Alternatively, if there exists a stable relationship between risk premiums and interest rates, it could be used to predict the risk premium from the prevailing interest rate.

To test for stability, we obviously need to calculate risk premiums over a fairly long period of time. Prior to 1980, the only consistent set of data we could find came from Value Line, and, because of the work involved, we could develop risk premiums only once a year (on January 1). Beginning in 1980, however, we began collecting and analyzing Value Line data on a monthly basis, and in 1981 we added monthly estimates from Merrill Lynch and Salomon Brothers to our data base. Finally, in mid-1983, we expanded our analysis to include the IBES data.

Annual Data and Results, 1966–1984

Over the period 1966–1984, we used Value Line data to estimate risk premiums both for the electric utility industry and for industrial companies, using the companies included in the Dow Jones Industrial and Utility averages as representative of the two groups. Value Line makes a five-year growth rate forecast, but it also gives data from which one can develop a longer-term forecast. Since DCF theory calls for a truly long-term (infinite horizon) growth rate, we concluded that it was better to develop and use such a forecast than to

[5]Recently, a new type of service that summarizes the key data from most analysts' reports has become available. We are aware of two sources of such services, the Lynch, Jones, and Ryan's Institutional Brokers Estimate System (IBES) and Zack's Icarus Investment Service. IBES and the Icarus Service gather data from both buy-side and sell-side analysts and provide it to subscribers on a monthly basis in both a printed and a computer-readable format.

Exhibit 2. Estimated Annual Risk Premiums, Nonconstant (Value Line) Model, 1966–1984

January 1 of the Year Reported	Dow Jones Electrics			Dow Jones Industrials			
	k_{Avg}	R_F	RP	k_{Avg}	R_F	RP	(3) ÷ (6)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1966	8.11%	4.50%	3.61%	9.56%	4.50%	5.06%	0.71
1967	9.00%	4.76%	4.24%	11.57%	4.76%	6.81%	0.62
1968	9.68%	5.59%	4.09%	10.56%	5.59%	4.97%	0.82
1969	9.34%	5.88%	3.46%	10.96%	5.88%	5.08%	0.68
1970	11.04%	6.91%	4.13%	12.22%	6.91%	5.31%	0.78
1971	10.80%	6.28%	4.52%	11.23%	6.28%	4.95%	0.91
1972	10.53%	6.00%	4.53%	11.09%	6.00%	5.09%	0.89
1973	11.37%	5.96%	5.41%	11.47%	5.96%	5.51%	0.98
1974	13.85%	7.29%	6.56%	12.38%	7.29%	5.09%	1.29
1975	16.63%	7.91%	8.72%	14.83%	7.91%	6.92%	1.26
1976	13.97%	8.23%	5.74%	13.32%	8.23%	5.09%	1.13
1977	12.96%	7.30%	5.66%	13.63%	7.30%	6.33%	0.89
1978	13.42%	7.87%	5.55%	14.75%	7.87%	6.88%	0.81
1979	14.92%	8.99%	5.93%	15.50%	8.99%	6.51%	0.91
1980	16.39%	10.18%	6.21%	16.53%	10.18%	6.35%	0.98
1981	17.61%	11.99%	5.62%	17.37%	11.99%	5.38%	1.04
1982	17.70%	14.00%	3.70%	19.30%	14.00%	5.30%	0.70
1983	16.30%	10.66%	5.64%	16.53%	10.66%	5.87%	0.96
1984	16.03%	11.97%	4.06%	15.72%	11.97%	3.75%	1.08

use the five-year prediction.[6] Therefore, we obtained data as of January 1 from Value Line for each of the Dow Jones companies and then solved for k, the expected rate of return, in the following equation:

$$P_0 = \sum_{t=1}^{n} \frac{D_t}{(1+k)^t} + \left(\frac{D_n(1+g_n)}{k-g_n}\right)\left(\frac{1}{1+k}\right)^n. \quad (4)$$

Equation (4) is the standard nonconstant growth DCF model; P_0 is the current stock price; D_t represents the forecasted dividends during the nonconstant growth period; n is the years of nonconstant growth; D_n is the first constant growth dividend; and g_n is the constant, long-run growth rate after year n. Value Line provides D_t values for $t = 1$ and $t = 4$, and we interpolated to obtain D_2 and D_3. Value Line also gives estimates for ROE and for the retention rate (b) in the terminal year, n, so we can forecast the long-term growth rate as $g_n = b(ROE)$. With all the values in Equation (4) specified except k, we can solve for k, which is the DCF rate of return that would result if the Value Line forecasts were met, and, hence, the DCF rate of return implied in the Value Line forecast.[7]

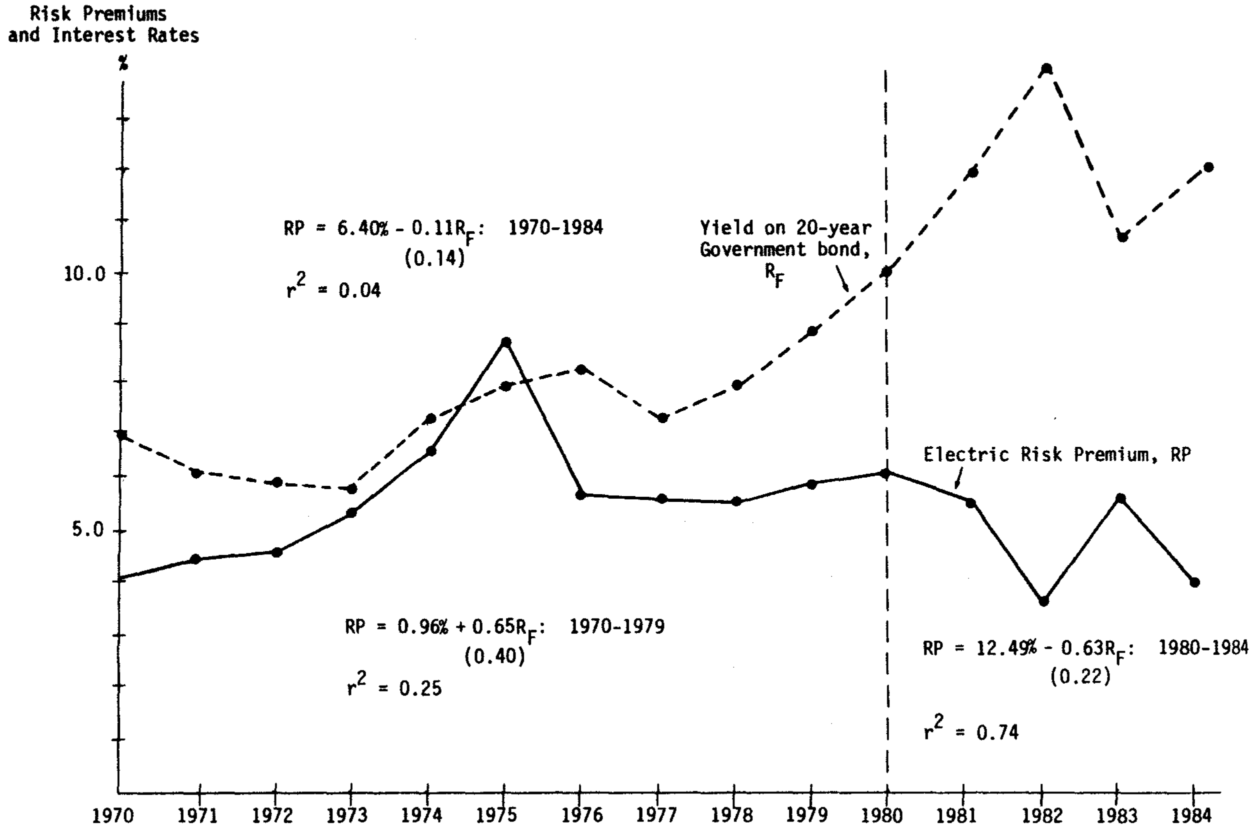
Having estimated a k value for each of the electric and industrial companies, we averaged them (using market-value weights) to obtain a k value for each group, after which we subtracted R_F (taken as the December 31 yield on twenty-year constant maturity Treasury bonds) to obtain the estimated risk premiums shown in Exhibit 2. The premiums for the electrics are plotted in Exhibit 3, along with interest rates. The following points are worthy of note:

1. Risk premiums fluctuate over time. As we shall see in the next section, fluctuations are even wider when measured on a monthly basis.
2. The last column of Exhibit 2 shows that risk premi-

[6]This is a debatable point. Cragg and Malkiel, as well as many practicing analysts, feel that most investors actually focus on five-year forecasts. Others, however, argue that five-year forecasts are too heavily influenced by base-year conditions and/or other nonpermanent conditions for use in the DCF model. We note (i) that most published forecasts do indeed cover five years, (ii) that such forecasts are typically "normalized" in some fashion to alleviate the base-year problem, and (iii) that for relatively stable companies like those in the Dow Jones averages, it generally does not matter greatly if one uses a normalized five-year or a longer-term forecast, because these companies meet the conditions of the constant-growth DCF model rather well.

[7]Value Line actually makes an explicit price forecast for each stock, and one could use this price, along with the forecasted dividends, to develop an expected rate of return. However, Value Line's forecasted stock price builds in a forecasted *change* in k. Therefore, the forecasted price is inappropriate for use in estimating current values of k.

Exhibit 3. Equity Risk Premiums for Electric Utilities and Yields on 20-Year Government Bonds, 1970–1984*



*Standard errors of the coefficients are shown in parentheses below the coefficients.

ums for the utilities increased relative to those for the industrials from the mid-1960s to the mid-1970s. Subsequently, the perceived riskiness of the two groups has, on average, been about the same.

3. Exhibit 3 shows that, from 1970 through 1979, utility risk premiums tended to have a positive association with interest rates: when interest rates rose, so did risk premiums, and vice versa. However, beginning in 1980, an inverse relationship appeared: rising interest rates led to declining risk premiums. We shall discuss this situation further in the next section.

Monthly Data and Results, 1980–1984

In early 1980, we began calculating risk premiums on a monthly basis. At that time, our only source of analysts' forecasts was Value Line, but beginning in 1981 we also obtained Merrill Lynch and Salomon Brothers' data, and then, in mid-1983, we obtained IBES data. Because our focus was on utilities, we restricted our monthly analysis to that group.

Our 1980–1984 monthly risk premium data, along with Treasury bond yields, are shown in Exhibits 4 and 5 and plotted in Exhibits 6, 7, and 8. Here are some comments on these Exhibits:

1. Risk premiums, like interest rates and stock prices, are volatile. Our data indicate that it would not be appropriate to estimate the cost of equity by adding the current cost of debt to a risk premium that had been estimated in the past. Current risk premiums should be matched with current interest rates.
2. Exhibit 6 confirms the 1980–1984 section of Exhibit 3 in that it shows a strong inverse relationship between interest rates and risk premiums; we shall discuss shortly why this relationship holds.
3. Exhibit 7 shows that while risk premiums based on Value Line, Merrill Lynch, and Salomon Brothers

Exhibit 4. Estimated Monthly Risk Premiums for Electric Utilities Using Analysts' Growth Forecasts, January 1980–June 1984

Beginning of Month	Value Line	Merrill Lynch	Salomon Brothers	Average Premiums	20-Year Treasury Bond Yield, Constant Maturity Series
Jan 1980	6.21%	NA	NA	6.21%	10.18%
Feb 1980	5.77%	NA	NA	5.77%	10.86%
Mar 1980	4.73%	NA	NA	4.73%	12.59%
Apr 1980	5.02%	NA	NA	5.02%	12.71%
May 1980	4.73%	NA	NA	4.73%	11.04%
Jun 1980	5.09%	NA	NA	5.09%	10.37%
Jul 1980	5.41%	NA	NA	5.41%	9.86%
Aug 1980	5.72%	NA	NA	5.72%	10.29%
Sep 1980	5.16%	NA	NA	5.16%	11.41%
Oct 1980	5.62%	NA	NA	5.62%	11.75%
Nov 1980	5.09%	NA	NA	5.09%	12.33%
Dec 1980	5.65%	NA	NA	5.65%	12.37%
Annual Avg.	5.35%			5.35%	11.31%
Jan 1981	5.62%	4.76%	5.63%	5.34%	11.99%
Feb 1981	4.82%	4.87%	5.16%	4.95%	12.48%
Mar 1981	4.70%	3.73%	4.97%	4.47%	13.10%
Apr 1981	4.24%	3.23%	4.52%	4.00%	13.11%
May 1981	3.54%	3.24%	4.24%	3.67%	13.51%
Jun 1981	3.57%	4.04%	4.27%	3.96%	13.39%
Jul 1981	3.61%	3.63%	4.16%	3.80%	13.32%
Aug 1981	3.17%	3.05%	3.04%	3.09%	14.23%
Sep 1981	2.11%	2.24%	2.35%	2.23%	14.99%
Oct 1981	2.83%	2.64%	3.24%	2.90%	14.93%
Nov 1981	2.08%	2.49%	3.03%	2.53%	15.27%
Dec 1981	3.72%	3.45%	4.24%	3.80%	13.12%
Annual Avg.	3.67%	3.45%	4.07%	3.73%	13.62%
Jan 1982	3.70%	3.37%	4.04%	3.70%	14.00%
Feb 1982	3.05%	3.37%	3.70%	3.37%	14.37%
Mar 1982	3.15%	3.28%	3.75%	3.39%	13.96%

Beginning of Month	Value Line	Merrill Lynch	Salomon Brothers	Average Premiums	20-Year Treasury Bond Yield, Constant Maturity Series
Apr 1982	3.49%	3.61%	4.29%	3.80%	13.69%
May 1982	3.08%	4.25%	3.91%	3.75%	13.47%
Jun 1982	3.16%	4.51%	4.72%	4.13%	13.53%
Jul 1982	2.57%	4.21%	4.21%	3.66%	14.48%
Aug 1982	4.33%	4.83%	5.27%	4.81%	13.69%
Sep 1982	4.08%	5.14%	5.58%	4.93%	12.40%
Oct 1982	5.35%	5.24%	6.34%	5.64%	11.95%
Nov 1982	5.67%	5.95%	6.91%	6.18%	10.97%
Dec 1982	6.31%	6.71%	7.45%	6.82%	10.52%
Annual Avg.	4.00%	4.54%	5.01%	4.52%	13.09%
Jan 1983	5.64%	6.04%	6.81%	6.16%	10.66%
Feb 1983	4.68%	5.99%	6.10%	5.59%	11.01%
Mar 1983	4.99%	6.89%	6.43%	6.10%	10.71%
Apr 1983	4.75%	5.82%	6.31%	5.63%	10.84%
May 1983	4.50%	6.41%	6.24%	5.72%	10.57%
Jun 1983	4.29%	5.21%	6.16%	5.22%	10.90%
Jul 1983	4.78%	5.72%	6.42%	5.64%	11.12%
Aug 1983	3.89%	4.74%	5.41%	4.68%	11.78%
Sep 1983	4.07%	4.90%	5.57%	4.85%	11.71%
Oct 1983	3.79%	4.64%	5.38%	4.60%	11.64%
Nov 1983	2.84%	3.77%	4.46%	3.69%	11.90%
Dec 1983	3.36%	4.27%	5.00%	4.21%	11.83%
Annual Avg.	4.30%	5.37%	5.86%	5.17%	11.22%
Jan 1984	4.06%	5.04%	5.65%	4.92%	11.97%
Feb 1984	4.25%	5.37%	5.96%	5.19%	11.76%
Mar 1984	4.73%	6.05%	6.38%	5.72%	12.12%
Apr 1984	4.78%	5.33%	6.32%	5.48%	12.51%
May 1984	4.36%	5.30%	6.42%	5.36%	12.78%
Jun 1984	3.54%	4.00%	5.63%	4.39%	13.60%

Exhibit 5. Monthly Risk Premiums Based on IBES Data

Beginning of Month	Average of Merrill Lynch, Salomon Brothers, and Value Line Premiums for Dow Jones Electrics	IBES Premiums for Dow Jones Electrics	IBES Premiums for Entire Electric Industry
Aug 1983	4.68%	4.10%	4.16%
Sep 1983	4.85%	4.43%	4.27%
Oct 1983	4.60%	4.31%	3.90%
Nov 1983	3.69%	3.36%	3.36%
Dec 1983	4.21%	3.86%	3.54%
Jan 1984	4.92%	4.68%	4.18%

Beginning of Month	Average of Merrill Lynch, Salomon Brothers, and Value Line Premiums for Dow Jones Electrics	IBES Premiums for Dow Jones Electrics	IBES Premiums for Entire Electric Industry
Feb 1984	5.19%	5.00%	4.36%
Mar 1984	5.72%	5.35%	4.45%
Apr 1984	5.48%	5.33%	4.23%
May 1984	5.36%	5.26%	4.30%
Jun 1984	4.39%	4.47%	3.40%
Average Premiums	4.83%	4.56%	4.01%

Exhibit 6. Utility Risk Premiums and Interest Rates, 1980–1984

Exhibit 7. Monthly Risk Premiums, Electric Utilities, 1981–1984 (to Date)

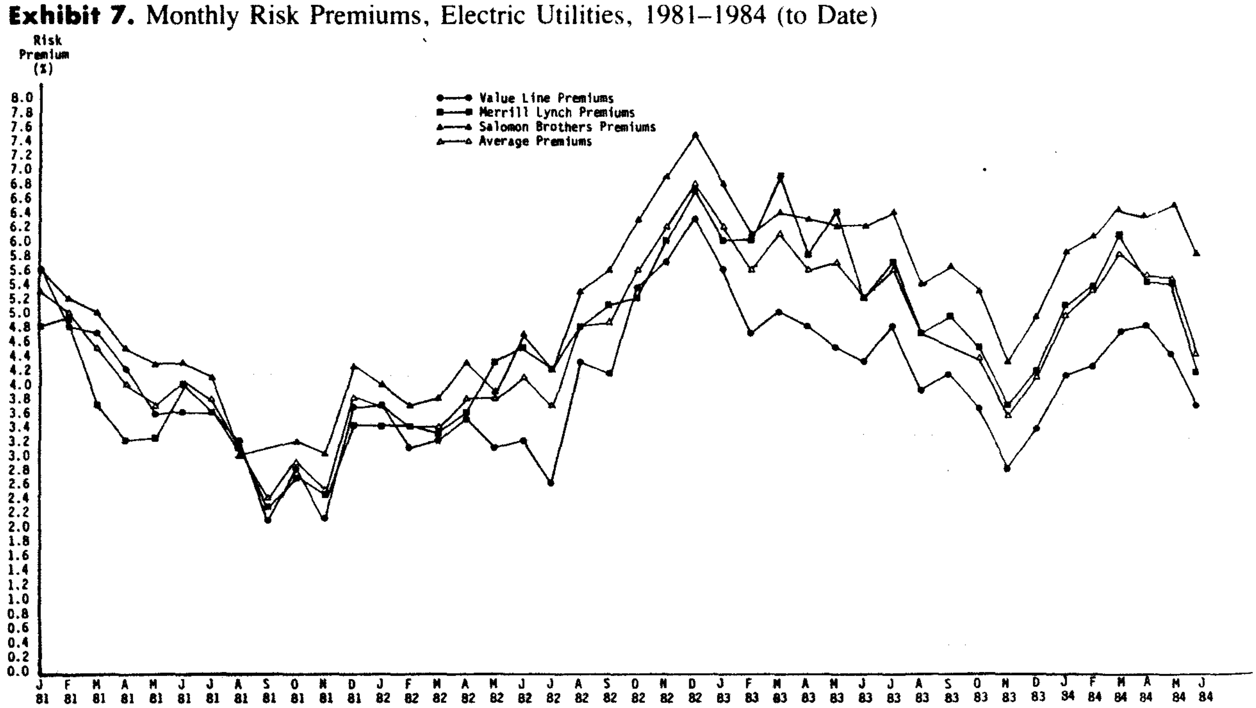
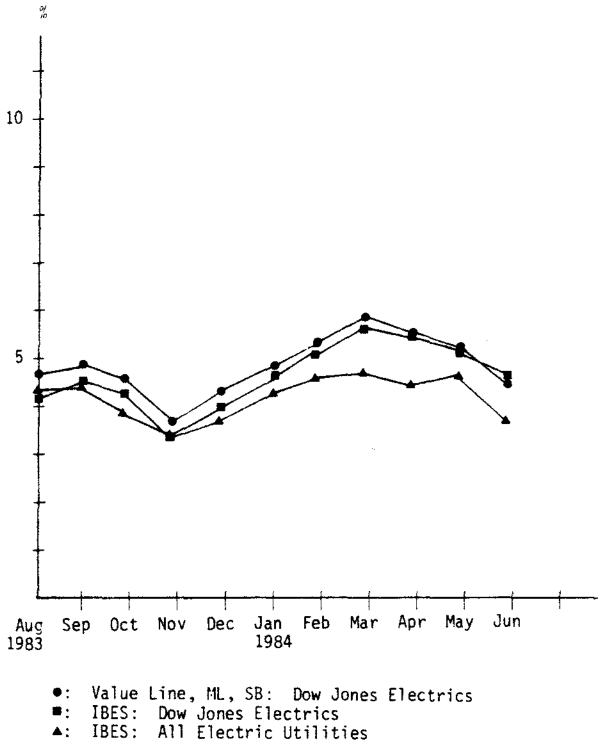


Exhibit 8. Comparative Risk Premium Data



do differ, the differences are not large given the nature of the estimates, and the premiums follow one another closely over time. Since all of the analysts are examining essentially the same data and since utility companies are not competitive with one another, and hence have relatively few secrets, the similarity among the analysts' forecasts is not surprising.

4. The IBES data, presented in Exhibit 5 and plotted in Exhibit 8, contain too few observations to enable us to draw strong conclusions, but (i) the Dow Jones Electrics risk premiums based on our three-analyst data have averaged 27 basis points above premiums based on the larger group of analysts surveyed by IBES and (ii) the premiums on the 11 Dow Jones Electrics have averaged 54 basis points higher than premiums for the entire utility industry followed by IBES. Given the variability in the data, we are, at this point, inclined to attribute these differences to random fluctuations, but as more data become available, it may turn out that the differences are statistically significant. In particular, the 11 electric utilities included in the Dow Jones Utility Index all have large nuclear investments, and this may cause them to be regarded as riskier than the industry average, which includes both nuclear and non-nuclear companies.

Tests of the Reasonableness of the Risk Premium Estimates

So far our claims to the reasonableness of our risk-premium estimates have been based on the reasonableness of our variable measures, particularly the measures of expected dividend growth rates. Essentially, we have argued that since there is strong evidence in the literature in support of analysts' forecasts, risk premiums based on these forecasts are reasonable. In the spirit of positive economics, however, it is also important to demonstrate the reasonableness of our results more directly.

It is theoretically possible to test for the validity of the risk-premium estimates in a CAPM framework. In a cross-sectional estimate of the CAPM equation,

$$(k - R_F)_i = \alpha_0 + \alpha_1\beta_i + u_i, \qquad (5)$$

we would expect

$$\hat{\alpha}_0 = 0 \text{ and } \hat{\alpha}_1 = k_M - R_F = \text{Market risk premium.}$$

This test, of course, would be a joint test of both the CAPM and the reasonableness of our risk-premium estimates. There is a great deal of evidence that questions the empirical validity of the CAPM, especially when applied to regulated utilities. Under these conditions, it is obvious that no unambiguous conclusion can be drawn regarding the efficacy of the premium estimates from such a test.[8]

A simpler and less ambiguous test is to show that the risk premiums are higher for lower rated firms than for higher rated firms. Using 1984 data, we classified the

[8] We carried out the test on a monthly basis for 1984 and found positive but statistically insignificant coefficients. A typical result (for April 1984) follows:

$$\underset{}{(k - R_F)_i} = \underset{(0.91)}{3.1675} + \underset{(1.44)}{1.8031}\ \beta_i.$$

The figures in parentheses are standard errors. Utility risk premiums do increase with betas, but the intercept term is not zero as the CAPM would predict, and α_1 is both less than the predicted value and not statistically significant. Again, the observation that the coefficients do not conform to CAPM predictions could be as much a problem with CAPM specification for utilities as with the risk premium estimates.

A similar test was carried out by Friend, Westerfield, and Granito [9]. They tested the CAPM using expectational (survey) data rather than *ex post* holding period returns. They actually found their coefficient of β_i to be negative in all their cross-sectional tests.

Exhibit 9. Relationship between Risk Premiums and Bond Ratings, 1984*

Month	Aaa/AA	AA	Aa/A	A	A/BBB	BBB	Below BBB
January†	—	2.61%	3.06%	3.70%	5.07%	4.90%	9.45%
February	2.98%	3.17%	3.36%	4.03%	5.26%	5.14%	7.97%
March	2.34%	3.46%	3.29%	4.06%	5.43%	5.02%	8.28%
April	2.37%	3.03%	3.29%	3.88%	5.29%	4.97%	6.96%
May	2.00%	2.48%	3.42%	3.72%	4.72%	6.64%	8.81%
June	0.72%	2.17%	2.46%	3.16%	3.76%	5.00%	5.58%
Average	2.08%	2.82%	3.15%	3.76%	4.92%	5.28%	7.84%

*The risk premiums are based on IBES data for the electric utilities followed by both IBES and Salomon Brothers. The number of electric utilities followed by both firms varies from month to month. For the period between January and June 1984, the number of electrics followed by both firms ranged from 96 to 99 utilities.
†In January, there were no Aaa/AA companies. Subsequently, four utilities were upgraded to Aaa/AA.

utility industry into risk groups based on bond ratings. For each rating group, we estimated the average risk premium. The results, presented in Exhibit 9, clearly show that the lower the bond rating, the higher the risk premiums. Our premium estimates therefore would appear to pass this simple test of reasonableness.

Risk Premiums and Interest Rates

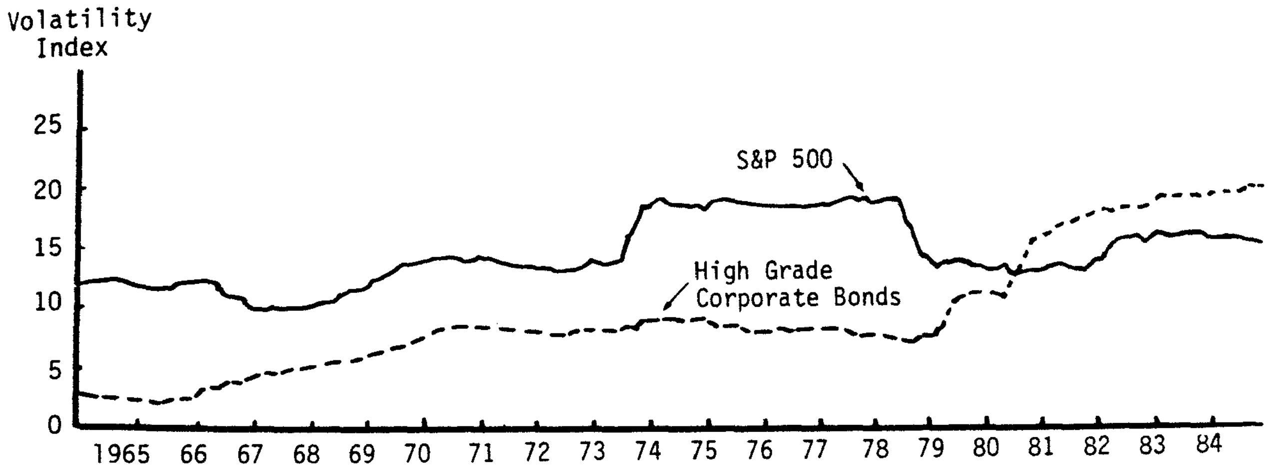
Traditionally, stocks have been regarded as being riskier than bonds because bondholders have a prior claim on earnings and assets. That is, stockholders stand at the end of the line and receive income and/or assets only after the claims of bondholders have been satisfied. However, if interest rates fluctuate, then the holders of long-term bonds can suffer losses (either realized or in an opportunity cost sense) even though they receive all contractually due payments. Therefore, if investors' worries about "interest rate risk" versus "earning power risk" vary over time, then perceived risk differentials between stocks and bonds, and hence risk premiums, will also vary.

Any number of events could occur to cause the perceived riskiness of stocks versus bonds to change, but probably the most pervasive factor, over the 1966–1984 period, is related to inflation. Inflationary expectations are, of course, reflected in interest rates. Therefore, one might expect to find a relationship between risk premiums and interest rates. As we noted in our discussion of Exhibit 3, risk premiums were positively correlated with interest rates from 1966 through 1979, but, beginning in 1980, the relationship turned negative. A possible explanation for this change is given next.

1966–1979 Period. During this period, inflation heated up, fuel prices soared, environmental problems surfaced, and demand for electricity slowed even as expensive new generating units were nearing completion. These cost increases required offsetting rate hikes to maintain profit levels. However, political pressure, combined with administrative procedures that were not designed to deal with a volatile economic environment, led to long periods of "regulatory lag" that caused utilities' earned ROEs to decline in absolute terms and to fall far below the cost of equity. These factors combined to cause utility stockholders to experience huge losses: S&P's Electric Index dropped from a mid-1960s high of 60.90 to a mid-1970s low of 20.41, a decrease of 66.5%. Industrial stocks also suffered losses during this period, but, on average, they were only one third as severe as the utilities' losses. Similarly, investors in long-term bonds had losses, but bond losses were less than half those of utility stocks. Note also that, during this period, (i) bond investors were able to reinvest coupons and maturity payments at rising rates, whereas the earned returns on equity did not rise, and (ii) utilities were providing a rising share of their operating income to debtholders versus stockholders (interest expense/book value of debt was rising, while net income/common equity was declining). This led to a widespread belief that utility commissions would provide enough revenues to keep utilities from going bankrupt (barring a disaster), and hence to protect the bondholders, but that they would not necessarily provide enough revenues either to permit the expected rate of dividend growth to occur or, perhaps, even to allow the dividend to be maintained.

Because of these experiences, investors came to regard inflation as having a more negative effect on utility stocks than on bonds. Therefore, when fears of inflation increased, utilities' measured risk premiums

Exhibit 10. Relative Volatility* of Stocks and Bonds, 1965–1984



*Volatility is measured as the standard deviation of total returns over the last 5 years.
Source: Merrill Lynch, *Quantitative Analysis*, May/June 1984.

also increased. A regression over the period 1966–1979, using our Exhibit 2 data, produced this result:

$$RP = 0.30\% + 0.73\ R_F; \qquad r^2 = 0.48.$$
$$(0.22)$$

This indicates that a one percentage point increase in the Treasury bond rate produced, on average, a 0.73 percentage point increase in the risk premium, and hence a 1.00 + 0.73 = 1.73 percentage point increase in the cost of equity for utilities.

1980–1984 Period. The situation changed dramatically in 1980 and thereafter. Except for a few companies with nuclear construction problems, the utilities' financial situations stabilized in the early 1980s, and then improved significantly from 1982 to 1984. Both the companies and their regulators were learning to live with inflation; many construction programs were completed; regulatory lags were shortened; and in general the situation was much better for utility equity investors. In the meantime, over most of the 1980–1984 period, interest rates and bond prices fluctuated violently, both in an absolute sense and relative to common stocks. Exhibit 10 shows the volatility of corporate bonds very clearly. Over most of the eighteen-year period, stock returns were much more volatile than returns on bonds. However, that situation changed in October 1979, when the Fed began to focus on the money supply rather than on interest rates.[9]

In the 1980–1984 period, an increase in inflationary expectations has had a more adverse effect on bonds than on utility stocks. If the expected rate of inflation increases, then interest rates *will increase* and bond prices *will fall*. Thus, uncertainty about inflation translates directly into risk in the bond markets. The effect of inflation on stocks, including utility stocks, is less clear. If inflation increases, then utilities should, in theory, be able to obtain rate increases that would offset increases in operating costs and also compensate for the higher cost of equity. Thus, with "proper" regulation, utility stocks would provide a better hedge against unanticipated inflation than would bonds. This hedge did not work at all well during the 1966–1979 period, because inflation-induced increases in operating and capital costs were not offset by timely rate increases. However, as noted earlier, both the utilities and their regulators seem to have learned to live better with inflation during the 1980s.

Since inflation is today regarded as a major investment risk, and since utility stocks now seem to provide a better hedge against unanticipated inflation than do

[9]Because the standard deviations in Exhibit 10 are based on the last five years of data, even if bond returns stabilize, as they did beginning in 1982, their reported volatility will remain high for several more years. Thus, Exhibit 10 gives a rough indication of the current relative riskiness of stocks versus bonds, but the measure is by no means precise or necessarily indicative of future expectations.

bonds, the interest-rate risk inherent in bonds offsets, to a greater extent than was true earlier, the higher operating risk that is inherent in equities. Therefore, when inflationary fears rise, the perceived riskiness of bonds rises, helping to push up interest rates. However, since investors are today less concerned about inflation's impact on utility stocks than on bonds, the utilities' cost of equity does not rise as much as that of debt, so the observed risk premium tends to fall.

For the 1980–1984 period, we found the following relationship (see Exhibit 6):

$$RP = 12.53\% - \underset{(0.05)}{0.63}\, R_F; \qquad r^2 = 0.73.$$

Thus, a one percentage point increase in the T-bond rate, on average, caused the risk premium to fall by 0.63%, and hence it led to a 1.00 − 0.63 = 0.37 percentage point increase in the cost of equity to an average utility. This contrasts sharply with the pre-1980 period, when a one percentage point increase in interest rates led, on average, to a 1.73 percentage point increase in the cost of equity.

Summary and Implications

We began by reviewing a number of earlier studies. From them, we concluded that, for cost of capital estimation purposes, risk premiums must be based on expectations, not on past realized holding period returns. Next, we noted that expectational risk premiums may be estimated either from surveys, such as the ones Charles Benore has conducted, or by use of DCF techniques. Further, we found that, although growth rates for use in the DCF model can be either developed from time-series data or obtained from security analysts, analysts' growth forecasts are more reflective of investors' views, and, hence, in our opinion are preferable for use in risk-premium studies.

Using analysts' growth rates and the DCF model, we estimated risk premiums over several different periods. From 1966 to 1984, risk premiums for both electric utilities and industrial stocks varied widely from year to year. Also, during the first half of the period, the utilities had smaller risk premiums than the industrials, but after the mid-1970s, the risk premiums for the two groups were, on average, about equal.

The effects of changing interest rates on risk premiums shifted dramatically in 1980, at least for the utilities. From 1965 through 1979, inflation generally had a more severe adverse effect on utility stocks than on bonds, and, as a result, an increase in inflationary expectations, as reflected in interest rates, caused an increase in equity risk premiums. However, in 1980 and thereafter, rising inflation and interest rates increased the perceived riskiness of bonds more than that of utility equities, so the relationship between interest rates and utility risk premiums shifted from positive to negative. Earlier, a 1.00 percentage point increase in interest rates had led, on average, to a 1.73% increase in the utilities' cost of equity, but after 1980 a 1.00 percentage point increase in the cost of debt was associated with an increase of only 0.37% in the cost of equity.

Our study also has implications for the use of the CAPM to estimate the cost of equity for utilities. The CAPM studies that we have seen typically use either Ibbotson-Sinquefield or similar historic holding period returns as the basis for estimating the market risk premium. Such usage implicitly assumes (i) that *ex post* returns data can be used to proxy *ex ante* expectations and (ii) that the market risk premium is relatively stable over time. Our analysis suggests that neither of these assumptions is correct; at least for utility stocks, *ex post* returns data do not appear to be reflective of *ex ante* expectations, and risk premiums are volatile, not stable.

Unstable risk premiums also make us question the FERC and FCC proposals to estimate a risk premium for the utilities every two years and then to add this premium to a current Treasury bond rate to determine a utility's cost of equity. Administratively, this proposal would be easy to handle, but risk premiums are simply too volatile to be left in place for two years.

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Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation

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Regulation FD made analysts less dependent on insider information and diminished analysts' motives to inflate their forecasts. The Global Research Analyst Settlement had an even bigger impact on analyst behavior: The mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. These results are similar for all analysts.

Our investigation of the impact of recent changes in regulation on analysts' forecasting behavior follows a number of studies that argued that analysts were motivated to produce research reports that did not reflect their true opinions. Analysts tended to make excessive "buy" recommendations and inflated earnings forecasts for several reasons, two of which gained considerable attention from regulators in the United States. First, analysts may have felt compelled to favor managers in covered companies in order to gain privileged access to information flow (Lim 2001). Second, although analysts are supposed to provide investors with accurate and truthful research reports, conflicts of interest could occur because analysts' compensation was tied to profits generated from investment banking business and brokerage commissions (Lin and McNichols 1998; Carleton, Chen, and Steiner 1998).

In the early part of the first decade of this century, in an effort to restore public confidence in U.S. capital markets, U.S. regulators enacted several rules and regulations, prosecuted analysts whose research reports were tainted by conflicts of interest, and fined banks that failed to prevent research analysts' conflicts of interest. Two of the main regulatory developments during this period were (1) Regulation Fair Disclosure (Reg FD), which became effective on 23 October 2000, and (2) the Global Research Analyst Settlement (Global Settlement), which was announced on 20 December 2002.[1]

Although the primary goals of these two regulatory actions are different, they both have the potential to improve the quality of analyst forecasts. One of the stated goals of Reg FD is to prohibit private communication between companies and analysts, thereby helping to level the playing field so that market participants can have equal access to information and making analysts less dependent on such communication. In prohibiting companies from selectively disclosing private information to analysts, Reg FD may reduce analyst forecast bias by eliminating the incentive for analysts to inflate their earnings forecasts in order to gain access to insider information.

The Global Settlement is an important enforcement agreement between U.S. regulators and 12 large investment banks (the Big-12 banks) designed to eliminate research analysts' conflicts of interest. If successful, the Global Settlement should reduce optimistic bias in analyst forecasts.

Our study considered whether these two actions by U.S. regulators reduced the bias in analysts' earnings forecasts documented in previous studies. We focused on annual earnings forecast bias for several reasons. First, investors may use analyst forecasts to form expectations of earnings and cash flows, both of which are important inputs for stock valuation models. Inflated earnings forecasts can drive stock prices above their fair values if investors fail to adjust for the bias.[2]

Second, given the flurry of new regulations, regulators clearly consider analyst behavior an important factor in maintaining investor confidence in financial markets. Regulation is costly because of the significant expenses associated with analyzing problematic situations and developing remedies. Moreover, restrictions and reporting requirements imposed on various market participants result in ongoing compliance costs. These costs can be justified only if the new regulations help reduce analysts' conflicts of interest and thereby generate an important benefit for financial markets.

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Third, most studies that have examined the impact of Reg FD and the Global Settlement on analyst behavior focused on forecast accuracy and forecast dispersion (Bailey, Li, Mao, and Zhong 2003; Agrawal, Chadha, and Chen 2006).[3] These aspects of analyst behavior, however, are little affected by conflicts of interest, the focus of our study.

Other studies have examined forecast bias. Clarke, Khorana, Patel, and Rau (2006) found that the Global Settlement had no impact on relative bias in analyst forecasts. Focusing on the impact of Reg FD on bias in quarterly earnings forecasts between October 1999 and December 2001, Mohanram and Sunder (2006) found that these forecasts became more optimistic after Reg FD but attributed the increase to unexpectedly low realized earnings during the 2001 recession. Our longer study period (1996–2006) allowed us to control for macroeconomic conditions in our regression analysis. Furthermore, we examined longer-term (up to 24 months) earnings forecasts in which the forecast bias is more apparent (Richardson, Teoh, and Wysocki 2004). Although Herrmann, Hope, and Thomas (2008) found some evidence of decline in forecast bias following Reg FD, they focused on internationally diversified companies only; we examined all U.S. companies, and our primary focus was on changes in forecast bias after the Global Settlement.

Lastly, the ability of analysts to forecast earnings accurately can be easily and straightforwardly verified because actual earnings are observed at the end of the forecast period. Barber, Lehavy, McNichols, and Trueman (2006) studied the change in distribution of stock recommendations made from 1996 to 2003. They found that the percentage of buys decreased starting in mid-2000.[4] How unbiased the new distribution of stock recommendations is, however, remains uncertain. But we know that the bias should be zero at the aggregate level when analysts make their forecasts on the basis of their true opinions.

Institutional Background

Historically—and especially before recent regulations—analysts have tended to make unduly optimistic earnings forecasts. In this section, we discuss the possible reasons for this optimistic bias and the potential impacts of the recent regulations on such bias.

Why Do Analysts Make Overoptimistic Earnings Forecasts? A number of studies have documented that analysts regularly make overoptimistic earnings forecasts (Brown 1997; Chopra 1998; Beckers, Steliaros, and Thomson 2004). Optimistic bias tends to be larger for longer-term forecasts and smaller for forecasts made closer to the earnings announcement date. This phenomenon is usually referred to as the walk-down trend (Richardson, Teoh, and Wysocki 2004). Several explanations have been offered for analyst optimism.

First, analysts may be influenced by conflicts of interest if their compensation is tied to investment banking fees and brokerage commissions. Lin and McNichols (1998) found that analysts affiliated with underwriters make more favorable stock recommendations and long-term earnings growth forecasts than analysts not so affiliated. Agrawal and Chen (2005) discovered that optimism in long-term earnings growth forecasts is high when analysts work for financial institutions whose revenues come mainly from brokerage business. Carleton, Chen, and Steiner (1998) found that stock recommendations made by brokerage firms are more optimistic than those of nonbrokerage firms. Using Australian data, Jackson (2005) noted that optimistic analysts generate more trades for their brokerage firms than do less optimistic analysts. Chan, Karceski, and Lakonishok (2007) showed that analysts' earnings forecasts are influenced by their desire to win investment banking clients. Doukas, Kim, and Pantzalis (2005) reported that stocks with excess analyst coverage yield lower future returns, consistent with the conflict-of-interest hypothesis. Hong and Kubik (2003) found that brokerage houses reward optimistic analysts; optimistic analysts at low-status brokerage houses are more likely to move up to higher-status brokerage houses than are less optimistic analysts.

Second, analysts may feel compelled to maintain good relations with company management in order to gain access to insider information that can help improve the accuracy of their forecasts (Lim 2001). Third, analysts may tend to cover stocks for which they have positive views and drop or avoid stocks for which they have negative views, which can induce a self-selection bias (McNichols and O'Brien 1997). Fourth, analysts may have a cognitive bias that leads them to overreact to good earnings information and underreact to bad earnings information (Easterwood and Nutt 1999; Nutt, Easterwood, and Easterwood 1999). Finally, the walk-down trend may be driven by the "earnings guidance game," in which analysts issue optimistic forecasts at the start of the fiscal year and then revise their estimates until the company can beat the forecast at the earnings announcement date (Richardson, Teoh, and Wysocki 2004).

Recent Regulations. Before Reg FD, analysts and institutional investors often had an informational advantage over small investors through private communications with management and conference calls in which company managers discussed past performance and provided guidance on future prospects. Such timely information gave these investment professionals an unfair advantage that allowed them to trade stocks profitably at the expense of uninformed investors.

To gain access to this information flow, analysts may have had to maintain good relations with insiders by making optimistic forecasts and buy recommendations in their research reports. Analysts' excessively optimistic views of the stocks were misleading and contributed to the deterioration of investor confidence in capital market integrity. Through Reg FD, which was introduced in October 2000, the U.S. SEC intended to improve fairness and restore public confidence in the markets by requiring U.S. public companies to disclose material information simultaneously to all market participants.

Other sources of conflicts of interest, however, remained unaddressed by Reg FD. For instance, analysts could be pressured to make optimistic forecasts and buy recommendations in order to favor investment banking clients and generate trading volume. The SEC and such self-regulatory organizations (SROs) as the National Association of Securities Dealers (NASD; now the Financial Industry Regulatory Authority [FINRA]) and the NYSE paid significant attention to this issue and introduced a number of new rules and regulations to curb the negative consequences of these conflicts of interest.

The Sarbanes–Oxley Act of 2002 (SOA), also known as the Public Company Accounting Reform and Investor Protection Act of 2002, became law on 30 July 2002. The SOA is a broad piece of legislation that covers various business practices, including auditor independence, corporate responsibility, enhanced financial disclosure, analysts' conflicts of interest, and corporate and criminal fraud accountability. The SOA amended the Securities Exchange Act of 1934 by creating Section 15D, which requires FINRA and the NYSE to adopt rules reasonably designed to address research analysts' conflicts of interest.

To comply with the SOA, the NASD released Rule 2711 (Research Analysts and Research Reports) and the NYSE amended its Rule 351 (Reporting Requirements) and Rule 472 (Communications with the Public). Most provisions of these rules went into effect on 9 July 2002. These rules mitigate analysts' conflicts of interest by separating research analysts from the influence of the investment banking and brokerage businesses. Research analysts' compensation can no longer be tied to the performance of these businesses. In addition, analysts are restricted from personal trading in the stocks they cover.

On 6 February 2003, the SEC adopted Regulation Analyst Certification (Reg AC).[5] Reg AC provides guidelines for proper disclosure of potential conflicts of interest of sell-side analysts, including their association with investment banking clients and the structure of their compensation.

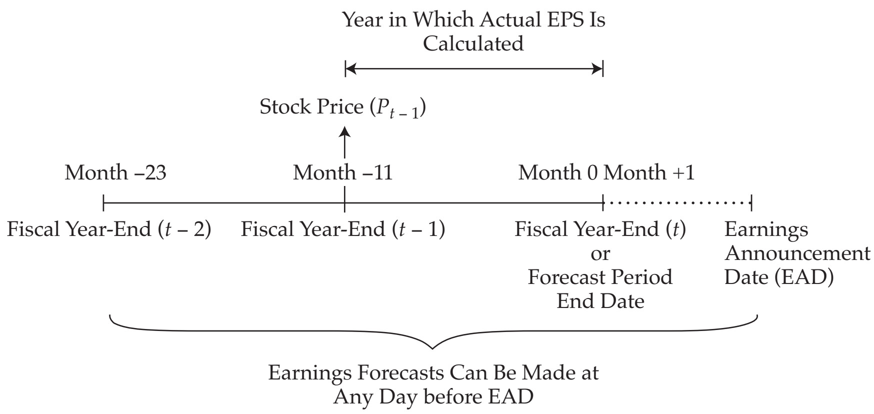
Regulatory objectives have also received support from rigorous enforcement actions. Following a joint investigation by the SEC, NASD, NYSE, and New York State Attorney General, 10 large U.S. and multinational investment banks agreed to pay a fine of $1.435 billion in the Global Research Analyst Settlement for their failure to adequately address research analysts' conflicts of interest. Announced on 20 December 2002, the terms of the Global Settlement initially covered 10 banks.[6] The final agreement was announced on 28 April 2003. Two more banks reached settlements on 26 August 2004.[7] The Global Settlement and the SRO rules share the same spirit in that their mutual objective is to eliminate analysts' conflicts of interest.

The introduction of these rules and regulations allows us to differentiate among the alternative explanations for analyst forecast bias proposed in the literature. First, a reduction in forecast bias after Reg FD would support the argument that analysts were overoptimistic owing to their need for insider information, especially if such a reduction were stronger for informationally more opaque companies. Second, a reduction in bias after the Global Settlement and Rule 2711 would be consistent with the hypothesis that analyst behavior was unduly influenced by conflicts of interest.[8] In contrast, self-selection and cognitive biases may exist even in a world without conflicts of interest. Therefore, if these biases are the main reasons for analysts' overoptimistic forecasts, then these regulatory changes should have no effect on forecast bias.[9]

Sample and Variables

We downloaded sell-side analysts' earnings forecasts for fiscal year-end dates between 1996 and 2006 from the Detail file of the I/B/E/S database. We used forecasts for current- and subsequent-year earnings per share (EPS), which are made for the upcoming and following years' earnings announcement dates.[10] **Figure 1** illustrates the timeline of analyst forecasts. The earliest analyst forecasts for a specific fiscal year-end EPS are made 24 months before the forecast fiscal year-end (in forecast month –23). For each EPS, analysts can

Figure 1. Timeline of Analyst Forecasts



make multiple forecasts over the course of the next 24 months. Some analysts may continue to make forecasts after the forecast fiscal year ends because companies announce their annual earnings after a delay of several months. Because the length of the EPS announcement delay could be affected by how high or low the realized EPS is relative to the consensus, we retained only those forecasts made no more than one month after the forecast fiscal year-end (in forecast month +1), which left us with a total of 2,297,792 forecasts.

For each forecast, I/B/E/S provides actual earnings, forecast date, forecast period (fiscal year) end, earnings announcement date, analyst code identity, broker code identity, and number of analysts used for consensus calculation.[11] We used the I/B/E/S Broker Translation file to convert broker codes into brokers' names, which we used to identify analysts who worked for the Big-12 banks. Stock prices are from the I/B/E/S Summary file.[12] We downloaded real GDP growth rates from the website of the U.S. Bureau of Economic Analysis. We downloaded SIC codes from the CRSP monthly file.

We defined analyst forecast bias, the focus of our analysis, as the average analyst forecast error and calculated it as follows:

$$Bias_{j,t,m} = 100\left(F_{j,t,m} - A_{j,t}\right)/P_{j,t-1}, \tag{1}$$

$$F_{j,t,m} = \frac{1}{I_{j,t,m}} \sum_{i=1}^{I} F_{j,t,m,i}, \tag{2}$$

and

$$F_{j,t,m,i} = \frac{1}{K_{j,t,m,i}} \sum_{k=1}^{K} F_{j,t,m,i,k}, \tag{3}$$

where

$A_{j,t}$ = the actual earnings per share for company j in fiscal year t

$F_{j,t,m,i}$ = the average of annual earnings forecasts for fiscal year-end t of company j, made in month m by analyst i

$K_{j,t,m,i}$ = the number of forecasts made in month m by the same analyst i for the same company j and fiscal year t

$I_{j,t,m}$ = the number of analysts making forecasts in month m for company j and fiscal year t

$P_{j,t-1}$ = the stock price of company j one year before the fiscal year-end t[13]

Note that all EPS forecasts made for the same company and the same fiscal year are normalized by the same stock price. Using the same stock price as the denominator guarantees that any changes in forecast bias across forecast months (m) are the result of changes in analyst forecasts, not of changes in the stock price. In our calculations according to Equations 1–3, we used only new forecasts made in month m. Stale forecasts from earlier months ($m - 1$, etc.) were not carried over into month m. In other words, each forecast participated in the calculation of the forecast bias only once, in the month in which the forecast was made. In our sample, an average analyst made 4.5 forecasts for each annual EPS. Because for each annual EPS we tracked 25-month forecasts (from month –23 to month +1), the implication is that an average analyst in our sample made a forecast for each covered company about once every six months.

To minimize the influence of outliers and misreported data in our analysis, we replaced with missing values any extreme observations of forecast bias, company size, market-to-book ratio, the number of stocks, and the number of industry analysts following.[14] We dropped from the sample all forecasts made in October 2000 and December 2002 (1.5 percent of our sample) and observations with missing values of any relevant variable. We were left with 1,586,000 individual analyst forecasts, which we used to calculate 434,268 average forecast errors. For each fiscal year and for each of our 7,315 sample companies, our sample contained up to 25 monthly observations of forecast bias ($Bias_{j,t,m}$).

Table 1 reports the summary statistics for the overall sample of 434,268 observations and for each of the three subperiods. The period before Reg FD represents 53 percent of our sample observations, with the period between Reg FD and the Global Settlement and the period after the Global Settlement representing 18 percent and 29 percent of the sample observations, respectively. The mean forecast bias across all sample observations is 1.39 percent of stock price. This result is consistent with prior evidence that analysts' forecasts are optimistically biased (Brown 1997; Chopra 1998). No significant difference exists between the mean forecast bias before Reg FD (1.72) and the mean forecast bias between Reg FD and the Global Settlement (1.97). The mean forecast bias is more than four times smaller after the Global Settlement (0.41), with the difference statistically significant at the 1 percent level.

The average market capitalization of companies in our sample was $4.5 billion, and the average market-to-book ratio was 3.57. On average, 8.41 analysts covered a company in any particular month. The analysts in our sample worked for brokers that, on average, each employed 65.7 analysts. A typical analyst followed 16.30 stocks from 4.78 industries and, at the time of the forecast, had been in the I/B/E/S database for 6.24 years and making forecasts for the covered stock for 2.5 years. Around 17 percent of forecasts were made for companies with negative earnings, and 36 percent of forecasts were made for companies whose earnings were declining relative to earnings in the prior fiscal year.

Test Results

In this section, we present the results of the univariate tests and of the regression analysis of the effects of Reg FD and the Global Settlement on bias in analyst forecasts.

Univariate Results by Forecast Month. **Table 2** presents the median forecasts by the month in which the forecasts were made and by the fiscal year for which they were made. The numbers in the leftmost column represent the month (relative to the fiscal year-end) of the forecast. The numbers in the top row represent the fiscal years for which the

Table 1. Summary Statistics

				Number of Observations			Mean		
Description	Variable	Number of Observations	Mean	Before Reg FD	Between Reg FD and GS	After GS	Before Reg FD	Between Reg FD and GS	After GS
Forecast bias	Bias	434,268	1.39	231,096	77,305	125,867	1.72	1.97	0.41
Reg FD indicator	RegFD	434,268	0.18	231,096	77,305	125,867	0.00	1.00	0.00
Global Settlement indicator	Glob	434,268	0.29	231,096	77,305	125,867	0.00	0.00	1.00
Company characteristics									
Analyst coverage	NumA	434,268	8.41	231,096	77,305	125,867	8.21	8.23	8.88
Market cap ($ millions)	CompanySize	434,268	4,470.00	231,096	77,305	125,867	3,480.00	5,250.00	5,800.00
Market-to-book ratio	MB	434,268	3.57	231,096	77,305	125,867	3.78	3.47	3.23
Negative EPS	EPSLoss	434,268	0.17	231,096	77,305	125,867	0.16	0.26	0.14
Declining EPS	EPSDecline	434,268	0.36	231,096	77,305	125,867	0.37	0.45	0.27
Litigation	Litigation	434,268	0.27	231,096	77,305	125,867	0.25	0.30	0.27
Labor intensive	Labor	434,268	0.61	231,096	77,305	125,867	0.60	0.63	0.63
Analyst characteristics									
Company-specific experience	YearStk	434,268	2.50	231,096	77,305	125,867	2.55	2.43	2.46
General experience	YearIBES	434,268	6.24	231,096	77,305	125,867	6.45	6.19	5.87
No. of stocks covered	NumStk	434,268	16.30	231,096	77,305	125,867	18.18	14.31	14.06
No. of industries covered	NumInd	434,268	4.78	231,096	77,305	125,867	5.46	4.15	3.93
Broker size	BrokerSize	434,268	65.70	231,096	77,305	125,867	54.98	89.03	71.06

Note: This table presents the summary statistics for the overall sample and for the three subperiods.

Table 2. Forecast Bias by Fiscal Year and Forecast Month

	Forecast Period End Year										
Month	96	97	98	99	00	01	02	03	04	05	06
–23	0.1	0.4	1.4	1.6	–0.3	1.9	2.3	1.2	–0.2	–0.3	–0.3
–22	0.3	0.5	0.9	1.3	0.5	2.2	2.7	1.3	0.0	–0.1	0.0
–21	0.3	0.5	1.1	1.6	0.5	2.1	2.6	1.3	0.0	0.0	0.2
–20	0.4	0.5	1.1	1.3	0.6	2.2	2.2	1.4	–0.1	0.0	0.0
–19	0.5	0.7	1.1	1.6	0.5	2.1	2.1	1.3	–0.1	0.0	0.1
–18	0.5	0.4	1.2	1.4	0.6	2.1	1.8	1.1	–0.2	0.0	0.1
–17	0.4	0.4	1.2	1.1	0.5	2.1	1.4	1.0	–0.2	0.0	0.1
–16	0.4	0.5	1.3	1.3	0.6	2.0	1.5	1.1	–0.1	0.0	0.2
–15	0.4	0.4	1.1	0.8	0.4	1.7	0.9	0.8	–0.3	0.0	0.2
–14	0.4	0.3	0.9	0.6	0.4	**FD**	0.6	0.4	–0.2	0.0	0.1
–13	0.4	0.3	1.0	0.6	0.4	1.5	0.5	0.3	–0.2	0.1	0.2
–12	0.3	0.2	0.8	0.4	0.3	1.6	0.4	**GS**	–0.2	–0.1	0.1
–11	0.3	0.3	0.8	0.3	0.1	1.3	0.3	0.1	–0.1	0.0	0.1
–10	0.2	0.2	0.5	0.1	0.2	1.1	0.2	0.0	–0.1	–0.1	–0.1
–9	0.2	0.2	0.6	0.1	0.1	1.1	0.2	0.0	–0.1	0.0	–0.1
–8	0.1	0.1	0.5	0.1	0.1	0.7	0.2	–0.1	–0.1	–0.1	–0.1
–7	0.1	0.0	0.5	0.1	0.1	0.6	0.2	–0.1	0.0	0.0	0.0
–6	0.1	0.1	0.4	0.0	0.1	0.5	0.2	–0.1	–0.1	–0.1	0.0
–5	0.0	0.0	0.2	0.0	0.0	0.2	0.1	–0.1	0.0	–0.1	0.0
–4	0.0	0.0	0.1	0.0	0.0	0.2	0.1	–0.1	0.0	0.0	0.0
–3	0.0	0.0	0.1	0.0	0.0	0.1	0.0	–0.1	–0.1	0.0	0.0
–2	0.0	0.0	0.0	0.0	**FD**	0.0	0.0	–0.1	–0.1	0.0	0.0
–1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	–0.1	0.0	0.0	–0.1
0	0.0	0.0	0.0	–0.1	0.0	0.0	**GS**	–0.1	0.0	0.0	–0.1
1	0.0	–0.1	0.0	–0.1	–0.1	0.0	0.0	–0.1	–0.1	–0.1	–0.3
Median bias	0.2	0.2	0.8	0.3	0.1	1.2	0.4	0.0	–0.1	0.0	0.0
Mean bias	1.2	1.1	1.8	2.2	1.4	3.0	2.1	1.6	0.1	0.5	0.3
Mean forecast	6.2	5.3	4.6	5.1	5.3	3.7	3.0	4.0	4.4	4.2	5.0
Mean actual earnings	5.0	4.1	2.8	2.9	3.9	0.7	0.9	2.4	4.2	3.7	4.7
Mean stock return (%)	0.2	0.2	0.0	0.2	0.0	0.0	–0.2	0.6	0.2	0.1	0.2
GDP (%)	3.7	4.5	4.2	4.5	3.7	0.8	1.6	2.5	3.9	3.2	3.3

Notes: *Forecast bias* is the difference between the mean of all forecasts made in a particular month for a particular company and a particular fiscal year and the realized EPS, scaled by the stock price and multiplied by 100. *Forecast period end year* is the fiscal year for which the forecast was made. *Month* is the month of the forecast relative to the fiscal year-end. *FD* is the month in which Reg FD became effective (October 2000). *GS* is the month in which the Global Settlement was announced (December 2002). Stock returns were calculated from our samples.

forecasts were made. For example, forecasts made in September 2000 for the fiscal year ended December 2000 (i.e., three months before the fiscal year-end) are in row –3 and column 00. The two solid lines separate the forecasts made before and after Reg FD and the forecasts made before and after the Global Settlement. The six bottom rows present forecast bias for each fiscal year averaged across all forecast months, along with the realized earnings per share, average forecasts, annual stock returns, and real GDP growth rates.[15] To align fiscal year-end dates with annual variables, such as real GDP growth rates, we used only forecasts for companies with December fiscal year-ends.

For each year before the Global Settlement, the median forecast errors are significantly positive. Furthermore, for each year before the Global Settlement, we observe the walk-down trend with forecast bias steadily declining as forecasts are made closer to the fiscal year-end. After the Global Settlement, we observe a significant drop in the forecast bias. The results show a total absence of bias in the median forecast errors for 2004–2006 (–0.1 percent, 0.0 percent, and 0.0 percent, respectively). The walk-down trend in median forecast errors is also practically nonexistent for fiscal years 2004–2006.

These results suggest that analysts' conflicts of interest indeed led to excess optimism in earnings forecasts before the Global Settlement and that the Global Settlement has been effective in neutralizing analysts' conflicts of interest. Alternative interpretations of the forecast bias, such as self-selection, cognitive bias, and need for insider information, cannot explain these findings because the Global Settlement should have no effect on these factors.

Unusually high stock valuations and/or realized earnings, rather than less optimistic forecasts, could be responsible for the decline in the average forecast errors after the Global Settlement. A quick look at the actual and forecasted EPS, stock returns, and real GDP growth rates before and after the Global Settlement, however, does not seem to support this idea. Neither aggregate economic performance nor stock valuations seem to be out of the ordinary in the post-settlement years. The actual earnings, stock returns, and GDP growth rates seem to be unusually low in the period between Reg FD and the Global Settlement. We controlled for the effects of these and other potentially relevant factors by examining the effects of Reg FD and the Global Settlement in a regression framework.

Regression Analysis. To examine how Reg FD and the Global Settlement affect bias in analyst forecasts while controlling for the confounding effects of company and analyst characteristics, as well as economic conditions, we estimated the following regression model:

$$\begin{aligned}
Bias_{j,t,m} &= \alpha_0 + \alpha_1 RegFD_{t,m} + \alpha_2 Glob_{t,m} + \alpha_3 NumA_{j,t,m} \\
&+ \alpha_4 CompanySize_{j,t,m-1} + \alpha_5 MB_{j,t,m-1} \\
&+ \alpha_6 YearStk_{j,t,m} + \alpha_7 YearIBES_{j,t,m} \\
&+ \alpha_8 NumStk_{j,t,m} + \alpha_9 NumInd_{j,t,m} \\
&+ \alpha_{10} BrokerSize_{j,t,m} + \alpha_{11} EPSLoss_{j,t} \\
&+ \alpha_{12} EPSDecline_{j,t} + \alpha_{13} Litigation_j \\
&+ \alpha_{14} Labor_{j,t,m-1} + \alpha_{15} ActualGDP_t \\
&+ \alpha_{16} UnexpectedGDP_{t,m} + \beta Month_m + \gamma Year_t \\
&+ \delta_j \sum DCompany_j + \varepsilon_{j,t,m}.
\end{aligned} \tag{4}$$

In Equation 4, $Bias_{j,t,m}$ is the mean forecast error for all forecasts for company j made in month m relative to the end of fiscal year t, calculated according to Equations 1–3. $RegFD_{t,m}$ equals 1 for forecasts made between 23 October 2000 and 20 December 2002. $Glob_{t,m}$ equals 1 for forecasts made after 20 December 2002. A negative sign for the coefficient of $RegFD_{t,m}$ or $Glob_{t,m}$ would indicate a decline in the bias following, respectively, Reg FD and the Global Settlement.

Lim (2001) argued that the forecast bias is higher when a company's information environment is less transparent—for example, when the company is small and has less analyst coverage. Beckers, Steliaros, and Thomson (2004) showed that the number of analysts following a stock affects the accuracy of the consensus earnings forecast. Hence, we used analyst coverage and company size as proxies for the degree of information transparency. Analyst coverage, $NumA_{j,t,m}$, is defined as the number of outstanding forecasts used in I/B/E/S's monthly consensus calculation. Analyst coverage represents the number of analysts following company j in month m for fiscal year t. $CompanySize_{j,t,m-1}$ is defined as the natural log of the company's market capitalization at the end of the previous month.

Analysts tend to forecast more accurately when they have more experience and resources (Clement 1999; Lim 2001). We measured company-specific experience as the number of years analyst i has been following company j ($YearStk_{j,t,m}$). We measured general experience as the number of years since analyst i first appeared in the I/B/E/S database ($YearIBES_{j,t,m}$). $BrokerSize_{j,t,m}$ is the number of analysts who work for the same employer during the same forecast year as the analyst who makes the forecast. Analysts who work for larger firms tend to have more resources at their disposal.

Clement (1999) found that analysts' forecasts are less accurate the more stocks and the more industries they follow. $NumStk_{j,t,m}$ is the number of stocks for which analyst i supplies at least one forecast within the calendar year. $NumInd_{j,t,m}$ is the number of two-digit SIC industries for which analyst i supplies at least one forecast within the calendar year.

Previous studies have found that forecasting is more difficult when companies report a loss or a decline in earnings (Brown 2001). The $EPSLoss_{j,t}$ indicator equals 1 when the corresponding actual earnings of company j are negative. The $EPSDecline_{j,t}$ indicator equals 1 when actual earnings in fiscal year t are lower than actual earnings in the previous year.

Matsumoto (2002) argued that companies in industries with a higher risk of shareholder lawsuits and/or greater reliance on implicit claims with stakeholders are more likely to avoid missing analyst forecasts. The $Litigation_j$ indicator equals 1 for companies in high-litigation-risk industries: SIC codes 2833–2836 (biotechnology), 3570–3577 and 7370–7374 (computers), 3600–3674 (electronics), and 5200–5961 (retailing).

Matsumoto (2002) also argued that labor-intensive companies try to avoid missing analyst forecasts because their stakeholders are concerned about company credit risk. Labor intensity, $Labor_{j,t,m-1}$, is defined as 1 minus the ratio of gross plant, property, and equipment (PPE) to total gross assets, where gross PPE is the quarterly Compustat item 118 and total gross assets is item 44 plus item 41. $Labor_{j,t,m-1}$ is measured at the end of the last quarter preceding forecast month m.

Richardson, Teoh, and Wysocki (2004) found lower forecast bias for companies with high growth opportunities. We used the market-to-book ratio ($MB_{j,t,m-1}$) at the end of the last quarter preceding the forecast month as a proxy for growth opportunities. The ratio is calculated as the market value of equity divided by the book value of common equity (Compustat quarterly data item 14 multiplied by item 61 and divided by item 59).

We used both the real GDP growth rate and the unexpected change in the real GDP growth rate to capture analysts' inability to forecast earnings accurately if the state of the economy changes substantially. $ActualGDP_t$ is the actual real GDP growth rate in fiscal year t. $UnexpectedGDP_{t,m}$ is defined as the difference between the expected real GDP growth rate and the actual real GDP growth rate in fiscal year t. For earnings forecasts made more than nine months before the fiscal year-end date, the expected real GDP growth rate in fiscal year t is defined as the real GDP growth rate in the quarter for which analysts made earnings forecasts. For forecasts made in Q2 (seven to nine months before the fiscal year-end date), we calculated the expected real GDP growth rate as (Growth in Q1 + 3 × Growth in Q2)/4. For forecasts made in Q3 (four to six months before the fiscal year-end date), we calculated the expected real GDP growth rate as (Growth in Q1 + Growth in Q2 + 2 × Growth in Q3)/4. For forecasts made within the three months before the fiscal year-end date, $UnexpectedGDP_{t,m}$ is set to zero.

Prior research and our results in Table 2 show that forecasts made earlier in the fiscal year are less accurate (Richardson, Teoh, and Wysocki 2004). To control for forecast horizon, we used $Month_m$, defined as the number of months until the fiscal year-end date. For example, for an analyst forecast made in October 1999 for the fiscal year ended December 1999, $Month_m$ equals 2. Richardson, Teoh, and Wysocki (2004) found that forecast bias has been declining gradually since the early 1990s. To address the concern that our results may be driven by this trend, we included a calendar year variable, $Year_t$, in the regression model (Equation 4). To control for unobserved company effects, we estimated the regressions with fixed company effects ($DCompany_j$).

The first set of estimation results in **Table 3** is for the regression model (Equation 4). The results imply that forecast bias declined by 0.24 percent of the stock price after the introduction of Reg FD. This finding confirms our earlier conjecture that the increase in forecast bias following Reg FD (observed in our univariate results) was driven by unexpectedly poor macroeconomic conditions. The decline in forecast bias following Reg FD is consistent with Lim's prediction (2001) that analysts become less optimistic when they rely less on insider information.

After the Global Settlement, the forecast bias is lower by 0.96 percent of the stock price compared with the forecast bias before Reg FD. This result is consistent with our univariate findings and implies that the Global Settlement and related regulations successfully neutralized analysts' conflicts of interest. The positive coefficient on *Month* suggests the presence of the walk-down trend. Forecast bias is high for earlier forecasts and becomes lower over time. On average, forecast bias increases by 0.14 percent of the stock price per month with the length of the forecast horizon.

Because the Global Settlement is an enforcement agreement between U.S. regulators and the Big-12 banks, we next examined whether the impact of the Global Settlement is limited to the Big-12 banks or whether there are spillover effects on other analysts.[16] In a recent study, Barber, Lehavy, McNichols, and Trueman (2006) reported that the proportion of buy recommendations declined significantly among all analysts after the implementation of NASD Rule 2711. They also documented that the decline was stronger for the sanctioned banks. Whether the Global Settlement has had a differential impact on analyst forecast bias, however, remains an open question.

To identify the differential impacts of Reg FD and the Global Settlement on Big-12 analysts, we compared the bias in the forecasts of Big-12 analysts with the bias in the forecasts of other analysts. In a univariate comparison, we found that, on average, the forecasts of analysts working for the Big-12 banks are statistically significantly less biased than the forecasts of their counterparts in each of the three periods. The differences, however, are economically trivial. For example, the difference between the mean forecast bias of Big-12 analysts and that of other analysts is –0.04 percent of the share price in the pre–Reg FD period, –0.09 percent after Reg FD, and –0.05 percent after the Global Settlement.

Table 3. The Impact of Reg FD and the Global Settlement on Forecast Bias

	(1)		(2)	
	Coefficient	*t*-Statistic	Coefficient	*t*-Statistic
RegFD	–0.24**	–3.29	–0.16*	–2.05
Glob	–0.96**	–10.68	–0.86**	–9.51
CompanySize	0.65**	16.89	0.67**	17.52
NumA	0.02**	3.39	0.01**	2.68
MB	–0.03**	–5.97	–0.03**	–5.59
YearStk	0.01	1.58	0.01**	2.59
YearIBES	0.00	1.54	0.00	0.78
NumStk	0.00*	–2.38	0.00*	–2.05
NumInd	–0.01	–1.18	–0.01	–1.40
BrokerSize	0.00	–1.64	0.00	–0.41
EPSLoss	5.40**	43.20	5.23**	40.53
EPSDecline	2.40**	62.82	2.38**	60.63
Litigation	–0.03	–0.24	–0.08	–0.66
Labor	0.52	2.12	0.47	1.89
ActualGDP	–0.04*	–2.05	–0.03	–1.23
UnexpectedGDP	–0.03**	–6.26	–0.04**	–6.61
Big12			–0.06**	–3.05
Big12 × RegFD			–0.07*	–2.04
Big12 × Glob			0.03	1.34
Month	0.14**	51.70	0.13**	47.76
Year	0.03*	2.16	0.02	1.09
Adjusted R^2	0.46		0.45	
No. of observations	434,268		434,268	
No. of companies	7,315		7,315	

Notes: This table presents the coefficients obtained from Equation 4. The dependent variable is earnings forecast bias, defined as the difference between the mean of all forecasts made in a particular month for a particular company and a particular fiscal year and the realized EPS, scaled by the stock price and multiplied by 100. The RegFD indicator equals 1 for forecasts made between 23 October 2000 and 20 December 2002. The Glob indicator equals 1 for forecasts made after 20 December 2002. Analyst coverage, NumA, is the number of outstanding forecasts used by I/B/E/S to calculate monthly consensus. CompanySize is the natural log of a company's market capitalization. Market-to-book ratio, MB, is the market value of equity divided by the book value of common equity. Company-specific experience, YearStk, is the number of years since the analyst made her first forecast for a particular stock. General experience, YearIBES, is the number of years since the first day the analyst appeared in I/B/E/S. NumStk and NumInd are the number of stocks and the number of industries covered by the analyst, respectively. The EPSLoss indicator equals 1 when the corresponding actual earnings of company *j* are negative. The EPSDecline indicator equals 1 when the realized earnings in fiscal year *t* are lower than the realized earnings in the previous year. BrokerSize is the number of analysts working for the employer of the analyst who makes the forecast. The litigation risk indicator, Litigation, equals 1 for companies in high-litigation-risk industries. Labor intensity, Labor, is (1 – Gross PPE/Total gross assets). The regressions are estimated with fixed company effects. The reported *t*-statistics reflect robust standard errors adjusted for heteroscedasticity and clustering by company.

*Significant at the 5 percent level.
**Significant at the 1 percent level.

To see whether the differential impacts of Reg FD and the Global Settlement on Big-12 and other analysts change when we control for company and analyst characteristics, as well as economic conditions, we re-estimated the regression model (Equation 4) with the Big-12 indicator and its interactions with the Reg FD and Global Settlement indicators included as additional independent variables.[17] The second set of results in Table 3 is for this regression. Consistent with our univariate results, the Big-12 indicator and its interaction with Reg FD are significant in statistical but not in economic terms. More importantly, the interaction of the Big-12 indicator with the Glob indicator is insignificant, both statistically and economically.

These results imply that both Big-12 and other analyst forecasts were biased before Reg FD, which is consistent with Lin and McNichols (1998), who found no difference between the earnings forecasts of analysts affiliated with banks involved in underwriting deals with the covered companies and the forecasts of unaffiliated analysts. These results also imply that the impact of the Global Settlement and related regulations is the same among Big-12 and other analysts. This finding may reflect the fear of non-Big-12 firms that they may become targets of similar investigations. In addition, because Big-12 banks no longer reward optimism, the incentive for lower-tier analysts to make optimistic forecasts as a means of moving up to the bigger banks has also been reduced. Finally, the rules and regulations introduced by the SEC, NYSE, and NASD around the time of the Global Settlement covered all analysts.

We checked the robustness of our main conclusion—that forecast bias declined after both Reg FD and the Global Settlement—in a number of ways. First, we used an alternative definition of the forecast bias by normalizing it by the book value of equity per share.[18] Second, we changed the cutoff dates for each period by using the effective date of Rule 2711 instead of the announcement date of the Global Settlement. Third, to ensure that our conclusions were unaffected by changes in the sample composition across the three subperiods, we required at least one forecast by the same analyst for the same company in all three periods. Fourth, we dropped observations with stock prices under $5 to avoid any potential biases induced when the scaling factor is a small number. Fifth, we extended our sample period to include an earlier period (January 1984–December 1995). In all these cases, the results (not reported here) remain qualitatively the same as those reported in Table 3, confirming that forecast bias declined after Reg FD and especially after the Global Settlement.

We also examined the breadth of these effects by estimating forecast bias regressions (Equation 4) separately for 12 business sectors and for subsamples formed on the basis of annual quintile sorts by company size and analyst coverage.[19] The results (not reported here) show that the effects of the Global Settlement are negative for 11 of 12 sectors and are statistically significant for 9 sectors. The effects of Reg FD are negative for 8 of 12 sectors, but significantly so for only 6 sectors. Our results also show that the effect of Reg FD is concentrated among smaller companies and companies with low analyst coverage, whereas the effect of the Global Settlement is more widespread, with no clear cross-sectional pattern.

Conclusion

Analysts' conflicts of interest were evident before the Global Research Analyst Settlement and were not limited to the 12 banks covered by it. Reg FD made analysts less dependent on insider information and thus diminished analysts' motives to favor company managers by inflating their earnings forecasts. The impact of Reg FD is more significant for companies with a less transparent information environment in which insider information has the most value.

Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that of related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.

We thank Donal Byard, Terrence Martell, and seminar participants at Baruch College for helpful comments. Armen Hovakimian gratefully acknowledges the financial support of the PSC-CUNY Research Foundation of the City University of New York.

This article qualifies for 1 CE credit, inclusive of 1 SER credit.

Notes

1. Several rules and regulations were enacted around the Global Research Analyst Settlement—for example, NASD Rule 2711, NYSE Rule 472, and Regulation Analyst Certification. Because they were introduced over a relatively short period, determining the separate impact of each one of these regulatory actions is impossible. Nevertheless, all these rules and regulations share the same goal of reducing analysts' conflicts of interest. Therefore, we use the term Global Settlement to represent all the rules and regulations enacted around the Global Research Analyst Settlement to address analysts' conflicts of interest.
2. Scherbina (2004) found a negative relationship between the estimated bias that arises from self-selection in coverage and subsequent stock returns. Her results suggest that retail

investors fail to adjust for the bias. Malmendier and Shanthikumar (2007) found that retail investors react to stock recommendations literally. Institutional investors buy stocks that have "strong buy" ratings and sell stocks that have "buy" ratings, whereas retail investors buy in both cases. Kwag and Shrieves (2006) found that persistence in forecast errors can lead to potentially profitable trading strategies.

3. Overall, these studies found either no change (Bailey, Li, Mao, and Zhong 2003) or a decrease in forecast accuracy (Agrawal, Chadha, and Chen 2006; Mohanram and Sunder 2006) and forecast dispersion (Agrawal, Chadha, and Chen 2006) following Reg FD.
4. Kadan, Madureira, Wang, and Zach (2009) documented that stock recommendations have become less optimistic since the Global Settlement. Furthermore, they found that the likelihood of an optimistic recommendation is no longer associated with analyst affiliation. Ferreira and Smith (2006) found that investors have not changed the way they respond to analysts' changes in recommendations since Reg FD. Examining bid–ask spreads and trading activity following Reg FD, Lee, Rosenthal, and Gleason (2004) found no significant increase in volatility or in the adverse-selection component of bid–ask spreads.
5. Reg AC took effect on 14 April 2003. See the joint report by the NASD and NYSE (2005) for the effectiveness of the new rules.
6. The 10 investment banks are Bear Stearns, Citigroup, Credit Suisse First Boston, Goldman Sachs, J.P. Morgan, Lehman Brothers, Morgan Stanley, Merrill Lynch, UBS, and U.S. Bancorp Piper Jaffray. In 2008, Bear Stearns and Merrill Lynch were taken over because of their deteriorating financial positions, whereas Lehman Brothers ended up in bankruptcy. Because our sample period ends in 2006, these events did not affect our results.
7. These two investment banks are Deutsche Bank and Thomas Weisel Partners.
8. Because prior studies (e.g., Lin and McNichols 1998) found no cross-sectional differences in forecast bias between affiliated and unaffiliated analysts, one would not reasonably expect cross-sectional differences in the impact of the Global Settlement on these two analyst types.
9. Therefore, one would not reasonably expect cross-sectional differences in the impact of the Global Settlement on self-selection bias.
10. Forecasts for current-year EPS are the forecasts in I/B/E/S with code FPI 1. Forecasts for subsequent-year EPS are the forecasts in I/B/E/S with code FPI 2.
11. We excluded forecasts in the I/B/E/S Excluded Estimates file and forecasts for which actual earnings figures were missing.
12. The I/B/E/S Summary file contains monthly snapshots of consensus-level data and corresponding stock prices. The snapshots are as of the Thursday before the third Friday of every month. The reported stock prices in this file are the last available prices before the Thursday. I/B/E/S's earnings-related data and stock prices are split adjusted.
13. Using stock price to normalize forecast bias is common (see, e.g., Richardson, Teoh, and Wysocki 2004). Later in the article, we discuss the robustness of our findings to alternative scaling of analyst forecast errors.
14. We defined extreme values as those in 1 percent of both tails of the distribution. Variables that took only positive (negative) values were trimmed only on the right (left) tail of the distribution.
15. Realized earnings and forecasts are scaled by the stock price, consistent with the scaling of the bias measure.
16. Other regulations, such as NASD Rule 2711, affect all analysts.
17. In this analysis, for each forecast month of each sample company-year, the mean forecast bias is calculated separately for Big-12 and other analysts.
18. This step also ruled out the possibility that such events as the decimalization of stock prices in August 2000–April 2001 affected our findings.
19. The sector classification for each company is from the I/B/E/S Identifier file.

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PLAYING Favourites

Bias in equity recommendations on Canadian stocks.

BY BIN CHANG

Analysts usually issue biased recommendations, that is, a disproportionately large percentage of favourable recommendations such as strong buy and buy. This bias in equity recommendations has led to a heated debate in both academia and the finance industry because equity analysts face a conflict of interest: on one hand, they are supposed to issue independent opinions about stocks, and on the other hand, they are compensated by the investment banking business that they generate. Since the latter is generally greater if recommendations are favourable, this may cause them to issue biased recommendations.

Aiming to reduce the bias in equity recommendations, Canadian regulators took a series of actions, with Policy 11 as the core framework. On April 12, 2001, the Securities Industry Committee on Analyst Standards released its draft report containing recommendations aimed at improving the independence of research and ensuring the professional practice of Canadian securities industry analysts. The Investment Dealers Association (IDA) published the initial proposed Policy 11 on July 5, 2002, a revised version on April 25, 2003, and a summary of comments on August 8, 2003. Policy 11 requires more disclosures from analysts and independence of research departments from investment banking departments. Also, in a letter dated August 15, 2002, the Ontario Securities Commission (OSC) requested information from financial institutions about current practices to address conflicts of interest relating to equity analysts. Accordingly, in September 2002, most financial institutions had adjusted their practice and replied to OSC.

The research on bias in recommendations on Canadian stocks is sparse. While Choi (2006) provides thoughts on the regulation of analysts in Canada, empirical studies in this area have not been conducted yet. In contrast, studies on American stocks are extensive, observing that U.S. analysts are biased on the grounds that the percentage of strong buy and buy recommendations out of all recommendations was 62% in 1993-2002.[1] Furthermore, analysts from investment banks were found to be more biased than independent analysts in that period, which is consistent with their above-mentioned conflict of interest. In 2002, the NYSE and NASD issued regulations to reduce the bias in equity recommendations, and the SEC fined 10 banks $1.435 billion for dishonest equity recommendations.[2] Research finds that the bias in U.S. equity analysts has been reduced since 2002.[3]

This paper studies four questions. First, was the bias in recommendations on Canadian stocks reduced after Policy 11? If so, were recommendations on Canadian stocks more biased than those of U.S. stocks? As many investment banks went out of business and investors' money was written off in the ongoing financial crisis, it is worthwhile to investigate investment banks' behaviour. Thus the third research question is: were investment banks more biased than other financial institutions? Finally, did investment banks issue more biased recommendations on cross-listed firms than on other firms?

THE RESEARCH

The data on analyst recommendations is obtained from the I/B/E/S Detailed History file from January 1993 to December 2006 for Canadian firms. Analysts

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generally rate stocks as "strong buy," "buy," "hold," "sell," and "strong sell." Analysts also use other labels such as "market underperform" and "market outperform," or "underweight" and "overweight," to convey their opinions. I/B/E/S standardizes the recommendations and converts them to five-tier numerical scores with one for strong buy, two for buy, three for hold, four for sell and five for strong sell. Note that this system is not consistently used in Canada and the U.S. because some financial institutions have changed from a five-tier rating system to a three-tier rating system including only buy, hold, and sell since 2002. Thus, following the literature on U.S. practices, this paper classifies all recommendations by only three categories: strong buy/buy, hold, and sell/strong sell for the whole sample period.

The sample includes 3,085 analysts who issued 94,404 recommendations from 1993 to 2006. The number of recommendations per year, the number of financial institutions, firms covered, and analysts increased throughout the sample. The total number of recommendations increased from 2,068 to 8,157. The number of financial institutions increased from 51 to 166, the number of covered firms increased from 392 to 817, and the number of analysts increased from 233 to 966.

This paper uses the percentage of strong buy/buy recommendations as the measure of bias. It is the number of strong buy/buy recommendations divided by the total number of all recommendations. If analysts are unbiased, the percentage of hold, sell, and strong sell should be reasonably large. A disproportionately large percentage of strong buy and buy recommendations represents a favourable bias. The percentage of strong/buy recommendations is favoured over average numerical scores because the fact that some financial institutions dropped the categories of strong buy and strong sell since 2002 makes the average numerical scores inconsistent across different rating systems. For example, a financial institution has 50% of recommendations in strong buy and 50% in buy. Since I/B/E/S records strong buy as one and buy as two, the average numerical score for this institution is 1.5 under the five-tier rating system. After it changes from a five-tier to a three-tier rating system, all strong buy/buy recommendations fall into the category of buy. Thus, the average numerical score becomes two regardless of the recommendations. As seen from this example, the average numerical score is inconsistent around the system change. Following the literature, we avoid this issue by using the percentage of strong buy/buy recommendations.

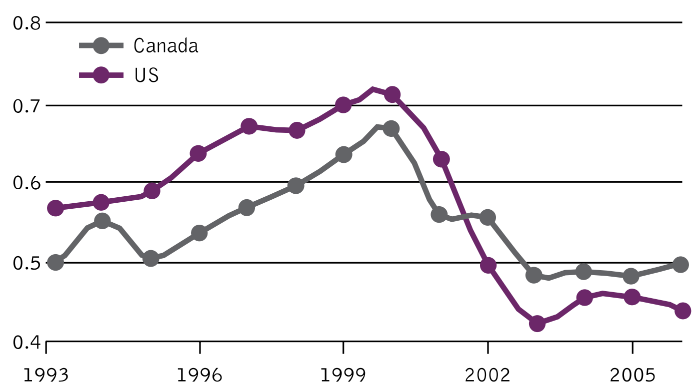
This paper compares the percentage of strong buy/buy recommendations in the pre-regulation period (1993-2002) with the post-regulation period (2003-2006). Ideally, if the expected percentage of strong buy/buy

TABLE 1: Tests of Difference in the Percentage of Strong Buy/Buy Recommendations

	Pre-Regulation	Post-Regulation	Difference	*p*-value
Canada	57%	49%	-8%	0.034**
U.S.	62%	44%	-18%	<0.001***
Difference	-6%	4%		
p-value	0.015**	0.034**		
Investment Banks	56%	47%	-9%	0.004***
Other financial institutions	58%	53%	-5%	0.093*
Difference	-2%	-6%		
p-value	0.555	0.010***		
Cross-listed firms/by investment banks	60%	44%	-16%	<0.001***
Other firms/ by investment banks	55%	45%	-10%	0.003***
Difference	5%*	-2%		
p-value	0.071	0.333		

*** significant at 1%, ** significant at 5%, and * significant at 10%

FIGURE 1: U.S. vs. Canada: Percent of Strong Buy/Buy Recommendations



Both the bursting of the technology bubble and the spillover of regulation may have contributed to the sharp reduction of the bias in 2001 and 2002. We use the S&P/TSX composite index to represent the Canadian stock market and the S&P 500 to represent the U.S. stock market.

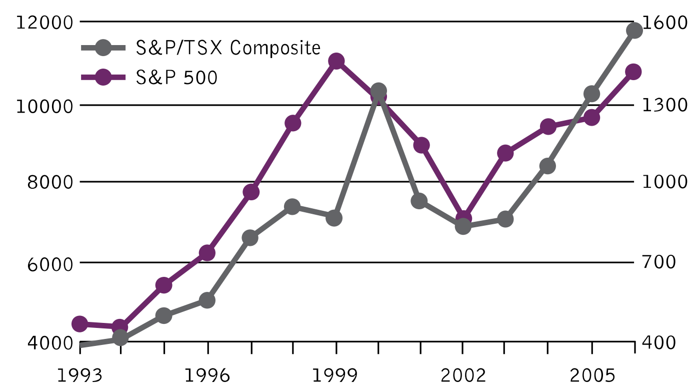
recommendations were known, bias could be measured as the difference between the actual percentage and the expected percentage. However, the expected percentage is difficult to estimate since it depends on the macro stock market condition and investment sentiment. Thus, we follow the literature[4] and compare the percentage in the pre-regulation and post-regulation periods. Year 2002 was set as the regulation year since the initial Policy 11 was published in 2002 and many financial institutions had adjusted their practice accordingly.

We first examine the change in the percentage of strong buy/buy recommendations. Figure 1 shows that in the U.S., the percentage of strong buy/buy recommendations decreased from 62% to 44% in the two sub-periods, which confirms the literature on the U.S. market. Furthermore, it provides new evidence that the bias on Canadian stocks increased consistently in the early sample period and reached the peak by 2000. The figure shows that bias dropped sharply and remained stable from 2003 to 2005. As seen in Table 1, the change in bias is 8%, which is statistically significant at the 5% level.

Also, as shown in Figure 1, the comparison between the bias on Canadian stocks and U.S. stocks reveals that recommendations on U.S. firms used to be more biased in the pre-regulation period, but they have become less biased since 2002. The greater reduction in bias on U.S. firms was due to tougher regulation. In December 2002, the Global Analyst Research Settlement ("Global Settlement") involving the sell-side research of the top ten U.S. investment banks was formally announced. These financial institutions were fined a total of $1.435 billion.[5] In contrast, no Canadian regulators have fined any financial institutions for bias in analysts' recommendations.

Both the bursting of the technology bubble and the spillover of regulation may have contributed to the sharp reduction of the bias in 2001 and 2002. We use the S&P/TSX composite index to represent the Canadian stock market and the S&P 500 to represent the U.S. stock market. Figure 2 shows that the Canadian stock market reached a peak in 2001 and the U.S. market reached a peak in 2000. After the peak, both markets touched the bottom in 2002. The bursting of the stock market bubble could have pulled down the expected percentage of strong buy/buy recommendations in 2001 and 2002. The difficulty of untangling the issue is compounded by the fact that, although the initial Policy 11 was published in 2002, regulators already paid attention to analysts' conflict of interest much earlier. In fact, the Securities Industry Committee on Analysts Standards issued a draft to address this issue in April 2001 and this topic had already been in the media. Thus it is likely that financial institutions started adjusting their practice in 2001.

FIGURE 2: S&P/TSX Composite vs. S&P 500



The effect of regulation rather than stock market performance contributed to the stable low bias from 2003 to 2006. As shown in Figure 2, both the Canadian and U.S. stock markets had bounced back since 2003 and kept an upward momentum until the end of the sample. In contrast, the percentage of strong buy/buy recommendations stayed at the low level. In order to exclude the impact of the bear market, we compare the percentage of favourable recommendations in the bull market: the 1993-2000 period and the 2003-2006 period. The unreported summary shows similar results with the bias decreasing from 57% to 49% in Canada (the change was statistically significant at the 5% level). Thus stock market performance cannot explain the low bias for the later sample period.

Next, this research dug deeper to test whether investment banks are more biased than other financial institutions since the conflict of interest from analysts of investment banks triggered the regulation. American research classifies affiliated analysts as analysts who work for banks with current investment banking ties to the corporations they cover and finds that they are biased. However, other research (Bradshaw, Richardson and Sloan (2003) and Clarke et al. (2006)) finds that even unaffiliated analysts are biased because they have incentives to issue optimistic research in order to increase their chances of generating future investment banking business from the firms they cover. Since both affiliated and unaffiliated analysts from investment banks are biased, we follow Bradshaw, Richardson and Sloan (2003) and Clarke et al. (2006) to compare analysts from investment banks with those from other financial institutions.

In Canada, the *Financial Post*, the *Globe and Mail*, and the IDA publish the number of investment banking deals, proceeds, and ranks of financial institutions every year. All financial institutions with investment banking business are classified as investment banks. Figure 3 shows the annual percentage of strong buy/buy recommendations for investment banks and other financial institutions separately. Prior to 2002, the bias from investment banks was 2% less than that from other financial institutions, although the difference is not statistically significant. This result contrasts with the U.S. study, which finds that investment banks are much more biased than non-investment banks in the U.S. and that larger bias led to new legislation to separate the research departments from the investment banking departments. A potential reason for the different findings across the border may be that there is less competition for investment banking business in Canada than there is in the U.S. In Canada, 74% of recommendations from investment banks come from five big Canadian banks, including RBC Financial Group, BMO Financial Group, TD Bank Financial Group, CIBC, and Scotiabank. These five banks together dominate both commercial banking and investment banking. Without tough competition, the motivation for the big five Canadian banks to issue favourable recommendations is not as strong as for their

FIGURE 3: Investment Banks vs. Other Financial Institutions: Percent of Strong Buy/Buy Recommendations

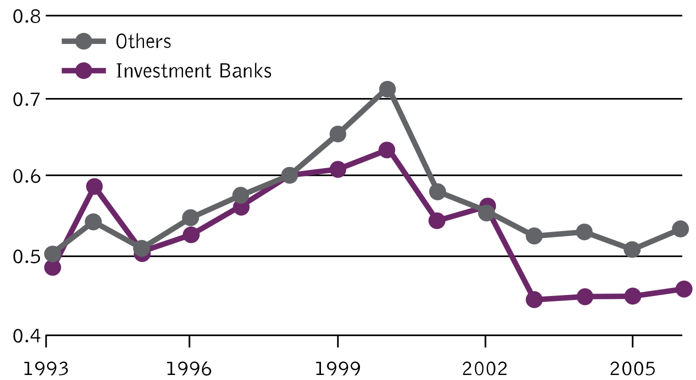
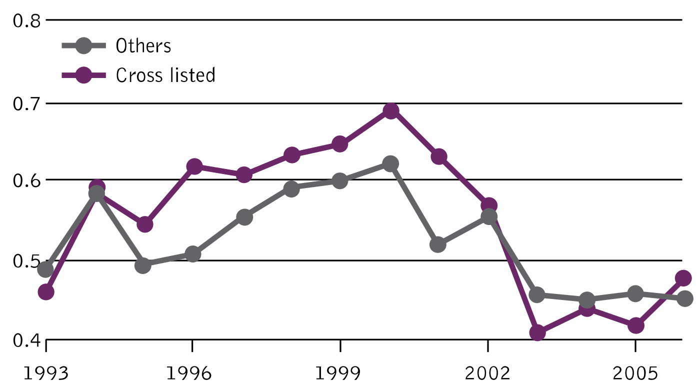


FIGURE 4: Cross-listed vs. Other Firms Covered by Canadian Banks: Percent of Strong Buy/Buy Recommendations



U.S. counterparts.

As shown in Figure 3, the gap between the percentage of strong buy/buy recommendations between investment banks and other financial institutions has actually increased since 2002—47% for investment banks and 53% for other financial institutions with a difference that was significantly different from 0 at the 1% level. This finding is similar to Clarke et al. (2006) who find that in the U.S., investment banks were the least likely to issue favourable recommendations after the regulation. Among these big five institutions, CIBC's bias dropped the most, from 63% to 34%. CIBC paid USD $2.4 billion in 2005 to settle an Enron lawsuit. CIBC's great reduction might be related to the investigation by U.S. regulators and courts.

It's also notable that each of the big five Canadian banks is cross-listed in the U.S. They operate businesses in the U.S. and issue recommendations on U.S. firms. They were very likely to be influenced by the U.S. regulation changes in 2002.[6] However, the impact of U.S. regulation on them is limited for the following reasons. First, with the exception of CIBC and RBC, they have very little presence in the U.S. investment banking business. Second, most of their recommendations are related to Canadian stocks rather than U.S. stocks.

Further, we investigate the bias on Canada and U.S. cross-listed firms. Up to 2006, more than 200 Canadian firms were listed in the U.S. market. The trend to inflate recommendations on U.S. firms must have affected those cross-listed firms. Thus cross-listed firms should suffer more from bias in equity recommendations than other Canadian firms in early periods. Also, since the reduction of biased recommendations on U.S. firms was larger than that of Canadian firms after 2002, the reduction of bias on cross-listed firms should be larger than that of other firms. Unfortunately, I/B/E/S does not provide the geography of the financial institutions, making the comparison of American and Canadian analysts on the same stocks impossible. However, we are still able to investigate investment banks' behaviour using the media reports mentioned above. As seen in Figure 4, the percentage of strong buy/buy recommendations was 60% on cross-listed firms and 55% on other firms in the pre-regulation period, but they were reduced to around 45% afterwards, which is consistent with the arguments above.

Overall, the findings are related to each of the four questions: recommendations on Canadian stocks in general after Policy 11, the comparison between bias on Canadian stocks and that on U.S. stocks, the breakdown within recommendations from financial institutions, and the breakdown within cross-listed firms and other firms. First, equity recommendations on Canadian firms were biased with 57% of recommendations being strong buy or buy prior to 2002. This provides a rationale for the Investment Dealers Association's Policy 11, which aimed to reduce bias in equity recommendations. This bias was greatly reduced to 49% after the enforcement of the policy, showing that the policy had a great effect. Second, compared to the U.S., the bias on Canadian stocks was less severe before 2002, but became greater after 2002 because the bias on U.S. stocks experienced a greater reduction due to tougher regulations. Third and most strikingly, investment banks in Canada are less biased than other financial institutions even before 2002, contradicting the U.S. literature in the same period. Finally, cross-listed firms suffered more bias from investment banks than other firms in the pre-regulation period, but experienced greater reduction in bias later. ■

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ENDNOTES

1. For biases among equity recommendations in U.S. firms, see Agrawal and Chen (2008), Bradley, Jordan and Ritter, (2008), Barber, Lehavy, McNichols, and Trueman (2001), Barber, Lehavy, and Trueman (2007), Clarke et al. (2006), Dugar and Nathan (1995), Kaden et al. (2006), Krigman, Shaw, and Womack (2001), Lin and McNichols (1998), McNichols and O'Brien (1997), Michael and Womack (1999), and Womack(1996).
2. For details about the Global Settlement, see http://www.sec.gov/spotlight/globalsettlement.htm.
3. For the changes in biases among equity recommendations in U.S. firms, see Clarke et al. (2006) and Kaden et al. (2006).
4. Clarke et al. (2006) and Kaden et al. (2006) compare the percentage of strong buy and buy recommendations in the pre-regulation and post-regulation period in the U.S.
5. The 10 financial institutions include Bear Stearns, Credit Suisse First Boston, Deutsche Bank, Goldman Sachs, J. P. Morgan Chase, Lehman Brothers, Merrill Lynch, Morgan Stanley, Salomon Smith Barney, and UBS Warburg.
6. We are thankful to the referees for providing us with this insight.

Attachment 5.21A

REFER TO LIVE SPREADSHEET MODEL

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(accessible by opening the Attachments Tab in Adobe)

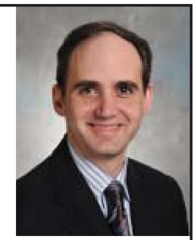
Attachment 5.21B

GMO

WHITE PAPER

August 2012

Reports of the Death of Equities Have Been Greatly Exaggerated: Explaining Equity Returns



Ben Inker

Where do equity returns come from? As questions go, it may not be quite as profound as "Why are we here?" or as embarrassingly baffling to most of us as "Why is the sky blue?", but considering the number of people out there who spend their working lives dealing in the financial markets, it is a question asked less often, and usually answered less well, than it should be. This paper will not pretend to tell the whole story, but in a time when investors are questioning what role equities should have in their portfolios, it is worth understanding where the returns to equities come from, and why, after a 12-year period in which U.S. equity returns have been negative, we can still be confident that the returns will, after all, be there in the long run.

We will begin with a summary of our basic points:

1) GDP growth and stock market returns do not have any particularly obvious relationship, either empirically or in theory.
2) Stock market returns can be significantly higher than GDP growth in perpetuity without leading to any economic absurdities.
3) The most plausible reason to expect a substantial equity risk premium going forward is the extremely inconvenient times that equity markets tend to lose investors' money.
4) The only time it is rational to expect that equities will give their long-term risk premium is when the pricing of the stock market gives enough cash flow to shareholders to fund that return.
5) Disappointing returns from equity markets over a period of time should not be viewed as a signal of the "death of equities." Such losses are necessary for overpriced equity markets to revert to sustainable levels, and are therefore a necessary condition for the long-term return to equities to be stable.

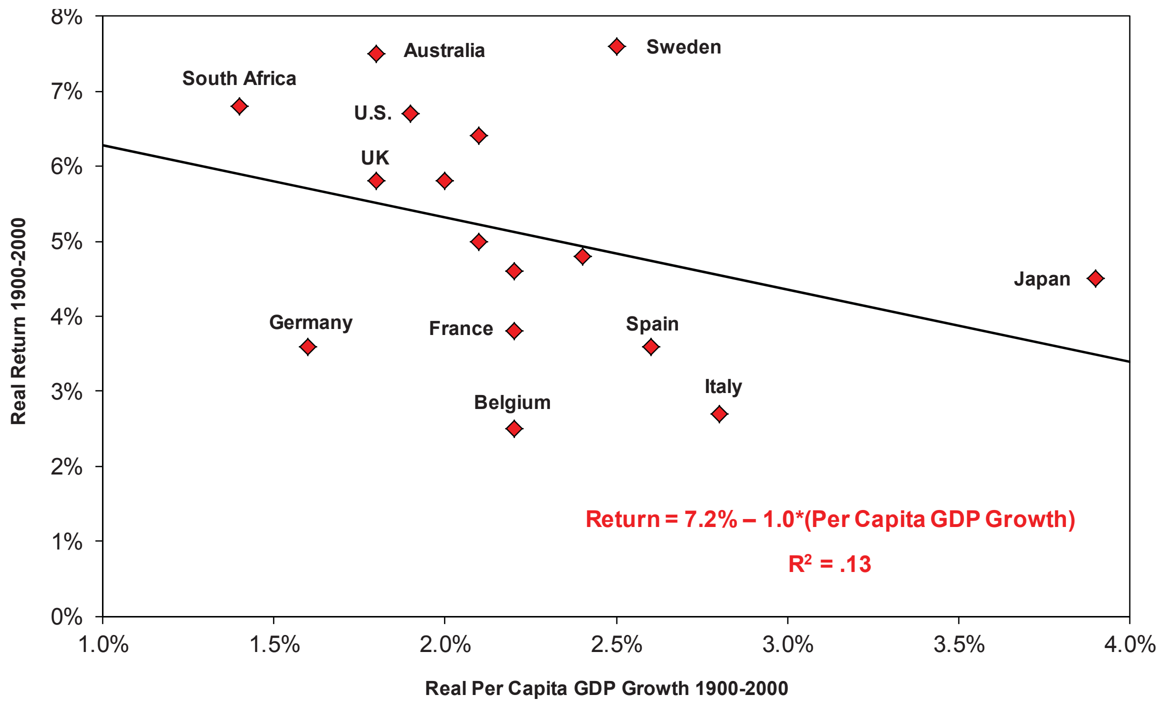
The first point to understand about stock returns is their relationship with GDP growth. In short, there isn't one. Stock returns do not require a particular level of GDP growth, nor does a particular level of GDP growth imply anything about stock market returns. This has been true empirically, as the Dimson-Marsh-Staunton data from 1900-2000 shows. Many investors are utterly convinced that strong GDP growth is the primary reason why one country's stock market will outperform another. As we can see in Exhibit 1, this was certainly not the case in the 20th century.

The trouble with picking stock markets on the basis of expectations of GDP growth is not that GDP growth is hard to predict (although it is harder than many people assume), it's that even if you could predict it with perfect accuracy, it wouldn't do you any good picking stock markets. As Exhibit 2 shows, this has also held true over the more recent time periods (in this case 1980-2010) and as Exhibit 3 shows, it has held true for emerging countries as well as developed ones.

Insofar as there is any relationship here, it's a perverse one. All else equal, higher GDP growth seems to be associated with lower stock markets returns. How could this possibly be? Don't earnings grow with GDP and stock prices with earnings? Aggregate corporate profits should indeed be expected to grow with GDP. And overall market capitalization of the stock market should be expected to grow along with aggregate earnings, as can be seen in the U.S. (Exhibit 4).

Exhibit 1

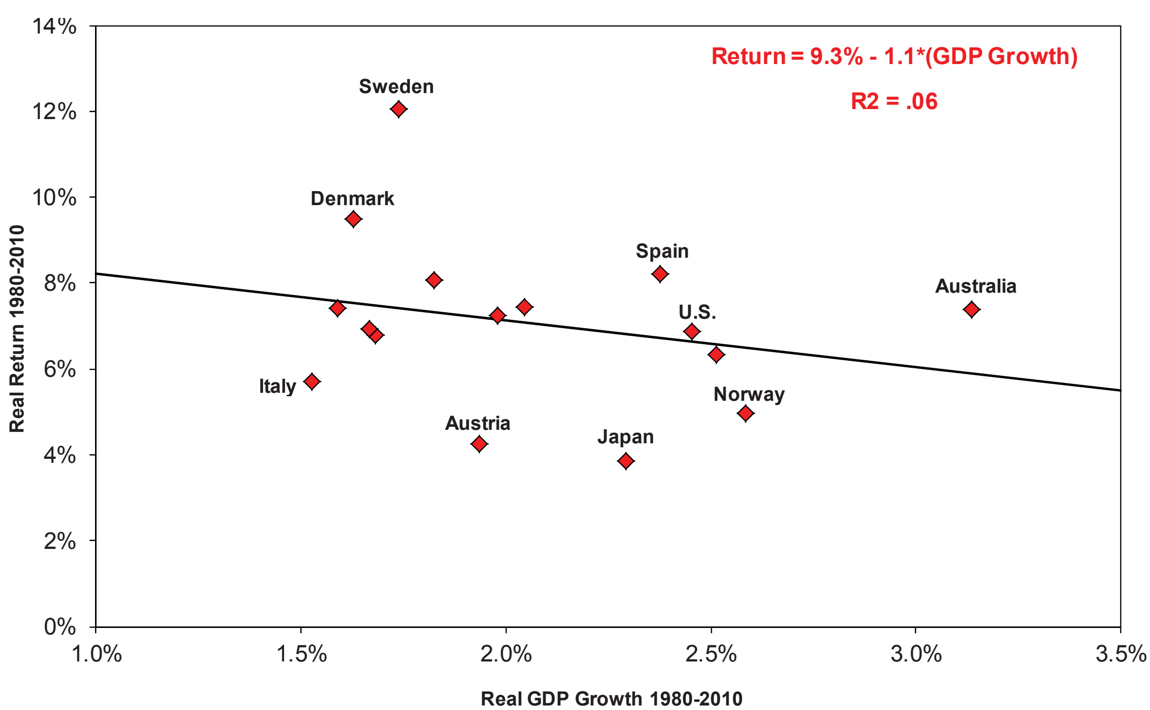
Stock Market Returns and GDP Growth, 1900-2000



Source: Dimson, Marsh, and Staunton, <u>Triumph of the Optimists</u>

Exhibit 2

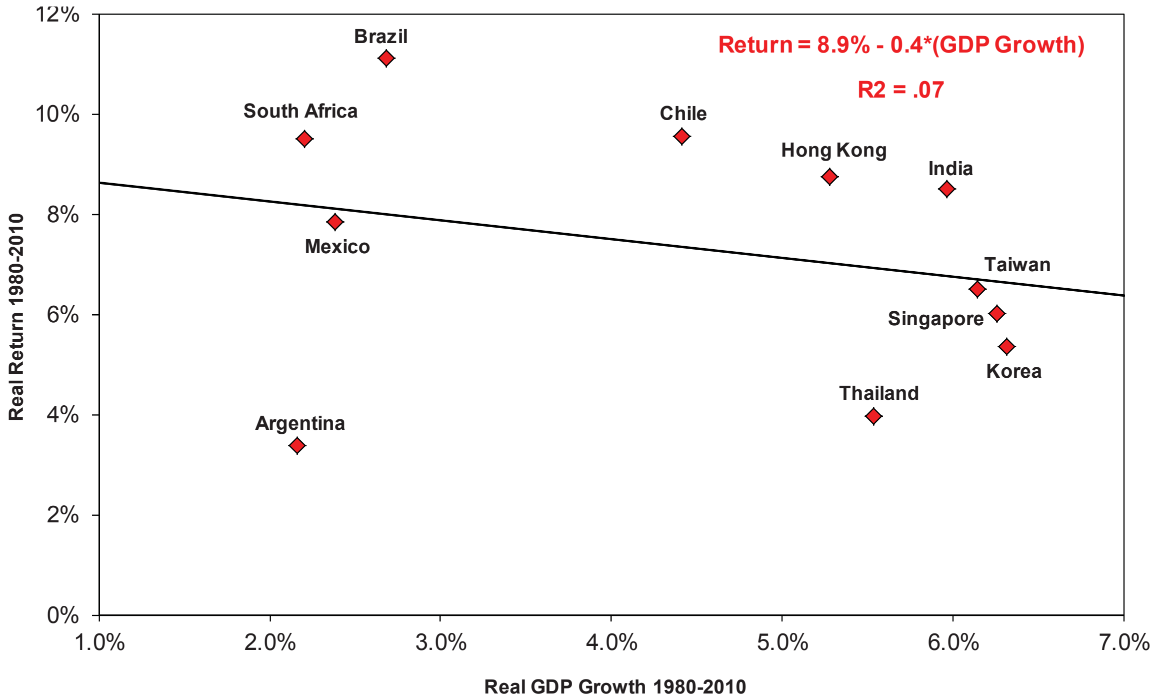
Stock Market Returns and GDP Growth for Developed Markets, 1980-2010



Source: MSCI, S&P, Datastream   As of 12/31/10

Exhibit 3

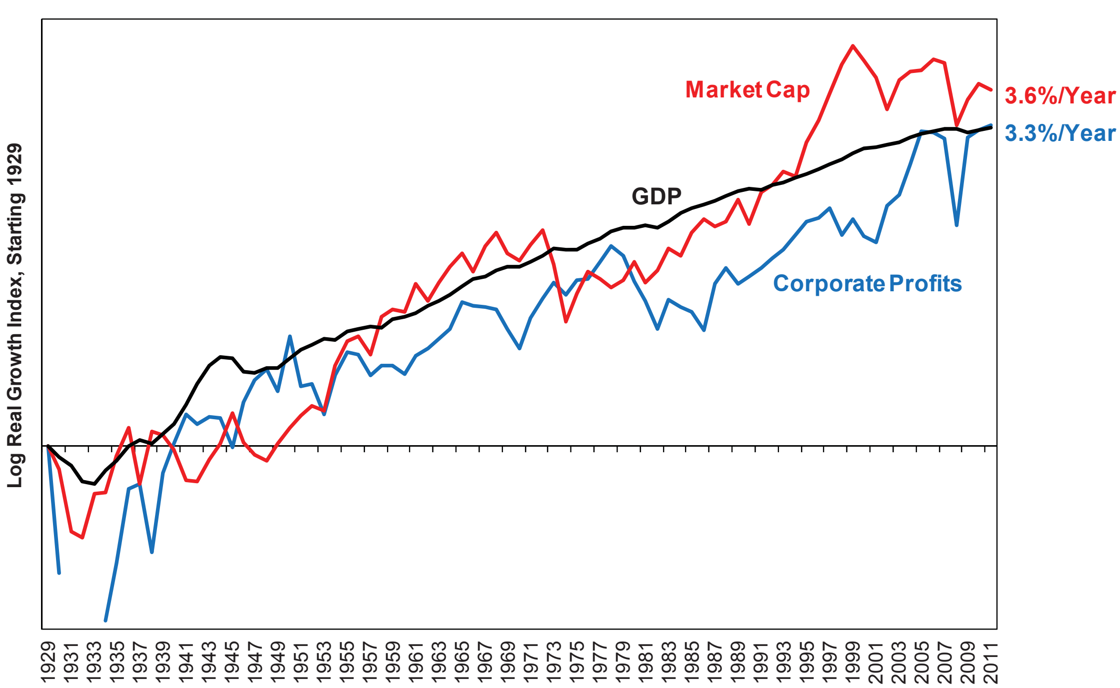
Stock Market Returns and GDP Growth for Emerging Markets, 1980-2010



Source: MSCI, S&P, Datastream As of 12/31/10

Exhibit 4

U.S. Profits and Market Cap vs. GDP



Source: BEA, Global Financial Data, Compustat As of 12/31/11

Since 1929,[1] market capitalization has grown at 3.6% real, while corporate profits and GDP have grown slightly more slowly at 3.3%. The trouble is that none of this tells us much of anything about what the return will be to an actual equity investor.

Total corporate profits and total stock market capitalization have very little to do with earnings per share or the compound return to shareholders because new companies, stock issuance by current companies, stock buybacks, and merger and acquisition activity can all place a wedge between the aggregate numbers and per share numbers.

To see why that wedge is so important, we should look at how GDP growth happens. GDP growth comes from a combination of two factors: population growth and labor productivity growth.

In thinking about the two, let's use a simple example of a factory in which 1 worker with 1 machine can output 1 widget per day. You are the factory owner, currently outputting 10 widgets per day with 10 workers and 10 machines. To achieve a 10% growth, you either need to hire another worker and buy another machine, or you need to improve or replace your machines such that they can output 1.1 widgets per day when manned by one worker. The first method increases output but not output per head, the second increases output as well as output per head. From your perspective as the owner, your choice between the two is going to be driven by the cost of improving or replacing the machines relative to the cost of paying another worker and buying another machine identical to your current ones. Both scenarios involve an investment on your part, though, so while the output of your factory has risen by 10%, we do not have enough information to determine your return on investment. It would only be 10% by the oddest of coincidences. You might have a unique widget creation technology such that your machines were twice as productive as any other, giving you a huge return on the investment. Widget production might be an utterly cutthroat competitive business, such that your return on investment is barely greater than your cost of capital (or, if you've screwed up your analysis, less than your cost of capital). Output is up 10%, and assuming no change to the price of widgets, your aggregate output and gross profits should be up 10% as well, if we don't take into account the cost of capital. But you as the owner had to invest to achieve that higher profit, and to do that, you either forwent a dividend you could have otherwise paid yourself out of profits, or had to raise the capital from someone else. The faster you want to grow, the more you will need to invest, but this investment must either come from retained earnings (forgone dividends) or dilution of shareholders.[2] In practice, companies in fast-growing countries generally exhibit both low dividend payout ratios and high rates of dilution of shareholders, both of which hurt shareholder returns enough to more than counteract the higher aggregate profit growth associated with fast growth.

When we look at stock market returns, dividends have a very large impact on the total, providing the bulk of equity investor returns for most of history. Exhibit 5 shows the compound growth of real returns and real earnings per share against real GDP. Unlike aggregate profits and market capitalization, it is fairly clear that neither returns nor EPS grow in line with GDP.

The gap between the 1.7% real earnings growth (about half the rate of GDP growth) and 5.9% real return (almost double the rate of GDP growth) is made up by dividends, which have averaged about 3.9% since 1929, and a bit of valuation shift (the P/E of the market is a couple of points higher today than it was in December of 1929). So if aggregate market capitalization has grown along with GDP and the compound return to equities has been much faster, what gives? Do those original shareholders control 8 times as much of economic output as they did 81 years ago? Of course they don't. Investors don't invest to simply accumulate wealth that is never to be spent. Workers invest to fund their retirements. Pension funds and insurance companies are obligated to service their required payouts. Endowments and foundations pay out 5% or so of their total value every year to fund the causes and organizations

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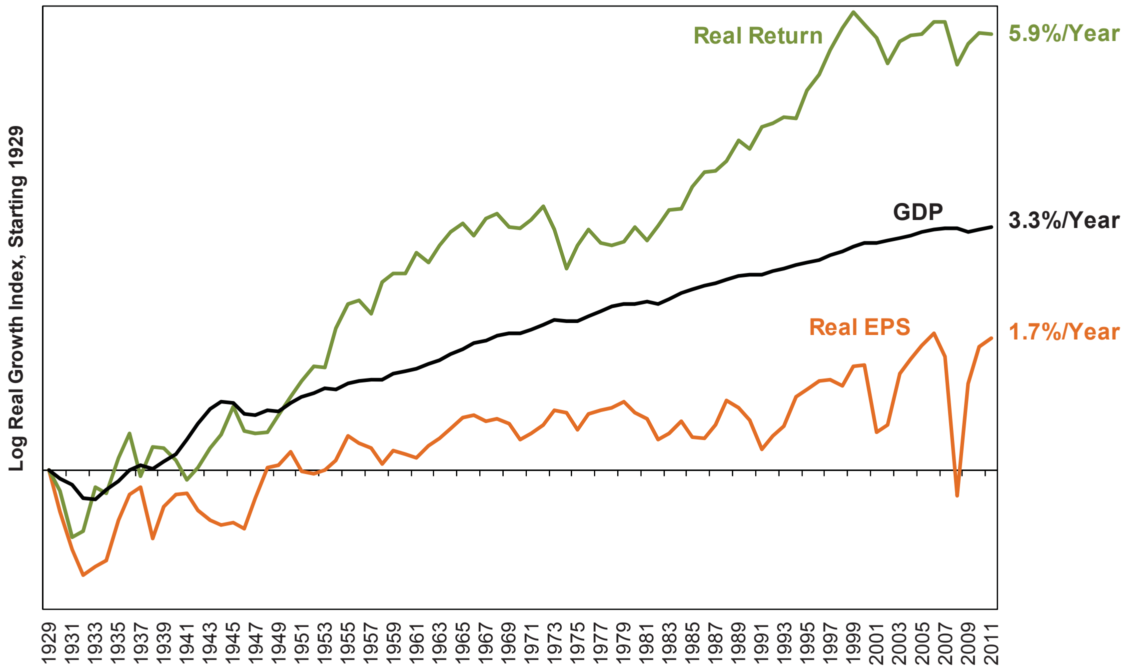
1 1929 is not a brilliant year to start a series on market capitalization or corporate profits, as it was the height of the 1920's economic boom and stock market bubble, but Bureau of Economic Analysis data tends to start there, so it is at least convenient, and over an 82-year period the starting point does not bias things too much.

2 For this purpose, I'm counting borrowing money as well as equity issuance as dilution of shareholders. Lenders may not officially have an ownership stake in the company, but they do have a right to some of its cash flow as well as having contingent rights under certain circumstances, i.e., bankruptcy or covenant breach.

Exhibit 5

S&P Total Return and EPS vs. GDP



Source: BEA, Robert Shiller   As of 12/31/11

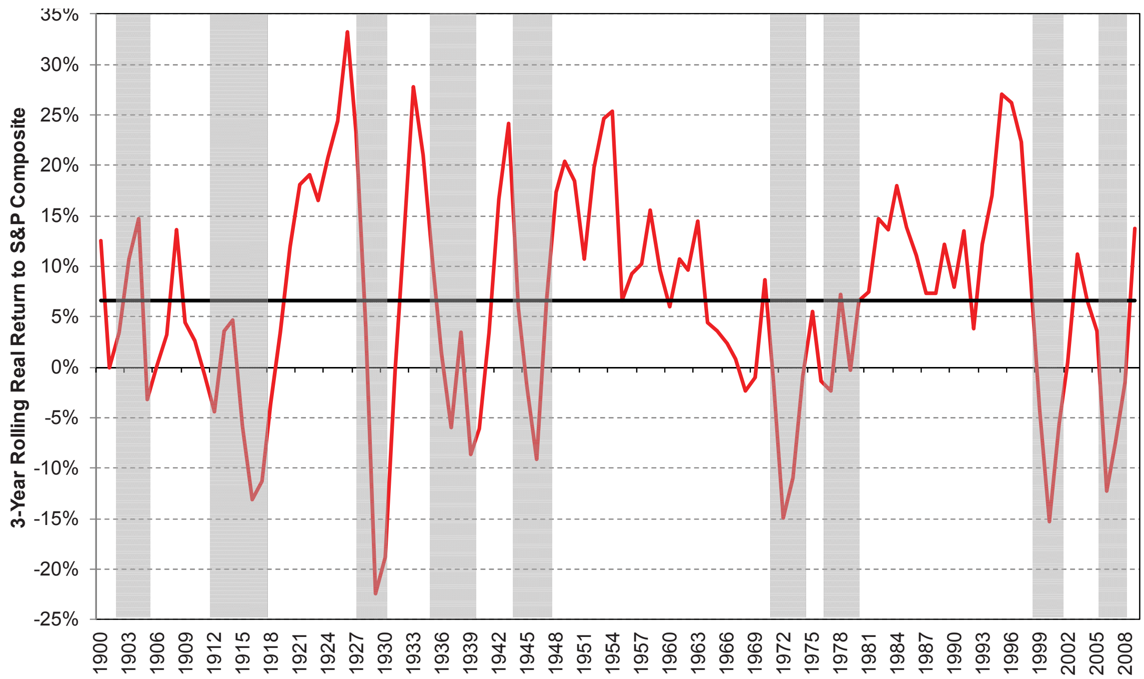
they exist to support. Even the entrepreneurs who seem to be intent on maximizing their wealth splash out on the occasional mega-yacht or scoop up a small tropical island from time to time.

To put it more simply, investors invest to fund future spending of some sort. A return on investment higher than GDP growth leads to no logical impossibility because those returns are not simply hoarded and reinvested in perpetuity. If a slow-growing country invests as if it was fast-growing, it will have a dismal return on equity, as Japan has ably demonstrated for the past couple of decades. But slow-growing countries like South Africa and Australia had very strong stock market returns in the 20th century, having had both the good sense not to lose a major war as well as a decent combination of cheap stock markets and good return on equity. Those returns funded plenty of spending by the holders of those equities, leaving their descendants possibly fairly well off, but not the owners of 140% of local GDP.

So why have returns to equity holders been so good over time? Is it really necessary to give a return of almost 6% real to entice investors to buy stocks? No one seems to have come up with a precise, convincing answer as to what return investors should demand from equities, but common sense suggests it should be a considerable return. This is not simply because equities are volatile – after all, a short position in equities is every bit as volatile as a long position, and they cannot both offer a return above cash – but because equities cost you money at such an inconvenient time. The worst returns to equities come in recessions (bad), financial crises (very bad), depressions (very, very bad), and major wars (not good at all). If you'll forgive me for not filling in the titles of the various bad events, Exhibit 6 shows the rolling 3-year real return to the S&P 500, with shaded areas denoting the losses associated with events from the Panic of 1907 through World War I and its ensuing depression, the Great Depression, World War II, the 1970's Oil Shocks, and on to the Global Financial Crisis. While the average return to the S&P 500 over this period was a reassuring 6.6% real, at those times when you were most at risk of losing your job, your bank account, your house, or your life, you could rely on equities to be piling on the misery.

Exhibit 6

S&P 500 Returns and "Bad Events"



Source: Robert Shiller, GMO As of 12/31/09

It is only rational for equity holders to demand a decent return for taking that very unfortunate return path. Furthermore, and just as crucially, we believe it is rational for companies to be willing to pay it. For corporations, equity is the safest capital they can raise. Unlike debt, there are no mandated payments associated with it, and no need to periodically refinance it. If a company is looking to finance investments with long durations and significant potential volatility to the cash flows generated, equity is the financing choice that minimizes the risk of the company going out of business. As a business owner, it is entirely rational to be willing to pay a higher expected rate of return to such "safe" capital.

The above statements do not actually specify what the required annual rate of return to equities must be. Here, we have to use some judgment. Our estimate for this return is 5.5-6.0% real, which is in line with the long-term returns to equities in the U.S. and elsewhere, about 3% higher than our estimate for high quality fixed income, and 4% above our long-term estimate for cash returns. We can't be entirely sure we are correct, but it would be decidedly odd if equities didn't offer a significantly higher return than high quality fixed income. It's not simply that equities are more volatile and have greater uncertainty than fixed income, but in recessions, depressions, and financial crises, high quality fixed income tends to go up rather than down.[3] Furthermore, long-duration fixed income is a natural fit for a number of large investors who have long-duration liabilities they are looking to match. An insurer or pension fund may well be interested in owning fixed income at very low expected returns as a hedge, while no one (with the possible exception of bankruptcy lawyers) could view a long position in equities as a hedge.

So while we can't specify the required return to equities with certainty, it makes sense that they should have a significantly higher required return than high quality fixed income. How can we go about forecasting this for the future? The utility functions of equity investors and issuers may be the determinant of long-term required returns to equities, but the only sustainable way to fund that return is out of corporate cash flow. If we stick with a corporate version of Hicksian income, where profit is the maximum amount a company could pay out to shareholders in a given

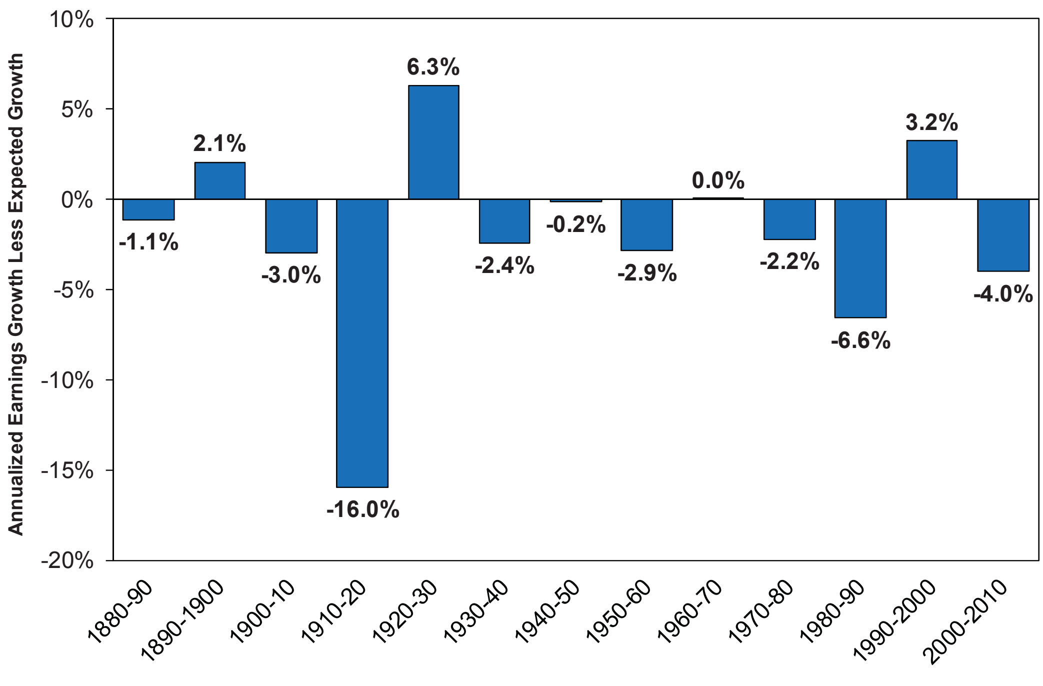
[3] The performance of bonds in the event of war depends a lot on whether your country is on the winning or losing side.

period and maintain the same real earnings power, we might expect that the long-term return to shareholders would be the earnings yield of the market. This is theoretically very simple and appealing. But when we do the math, it is difficult not to be a little disappointed on behalf of shareholders.

Since 1929, the average earnings yield on the S&P 500 has been 7.2%. The P/E of the market has also increased over the period from 13.8 to 15.8 on trailing net earnings. A naïve investor might therefore have expected to get a return of 7.4% above inflation, accounting for both the earnings yield and valuation shift. The actual return to the market since December 1929 has instead been 5.9% real. That's 1.5% worse than one might have expected. What gives? The short answer is that earnings growth has been 1.7% real since 1929, while retained earnings have averaged 3.3% of market cap. That 3.3% could have been paid out as dividends, and if our earnings were truly economic profit that maintained the companies' real earnings power, shareholders would have been able to pocket a dividend yield of 7.2% with flat real earnings. So, are corporations systematically flushing their retained earnings down the toilet? Possibly, but it's also quite possible that earnings are simply overstated. Earnings are calculated not by economists, but accountants, and our guess is that if corporations had indeed paid out 100% of stated earnings, real earnings per share would have fallen significantly over time. Estimating this "slippage" going forward is tricky, since it has not been consistent over time. If we compare earnings growth for the S&P 500 to what we would have expected given the level of retained earnings, we can see large disparities decade to decade, as shown in Exhibit 7.

Exhibit 7

Earnings Growth Slippage in the S&P 500



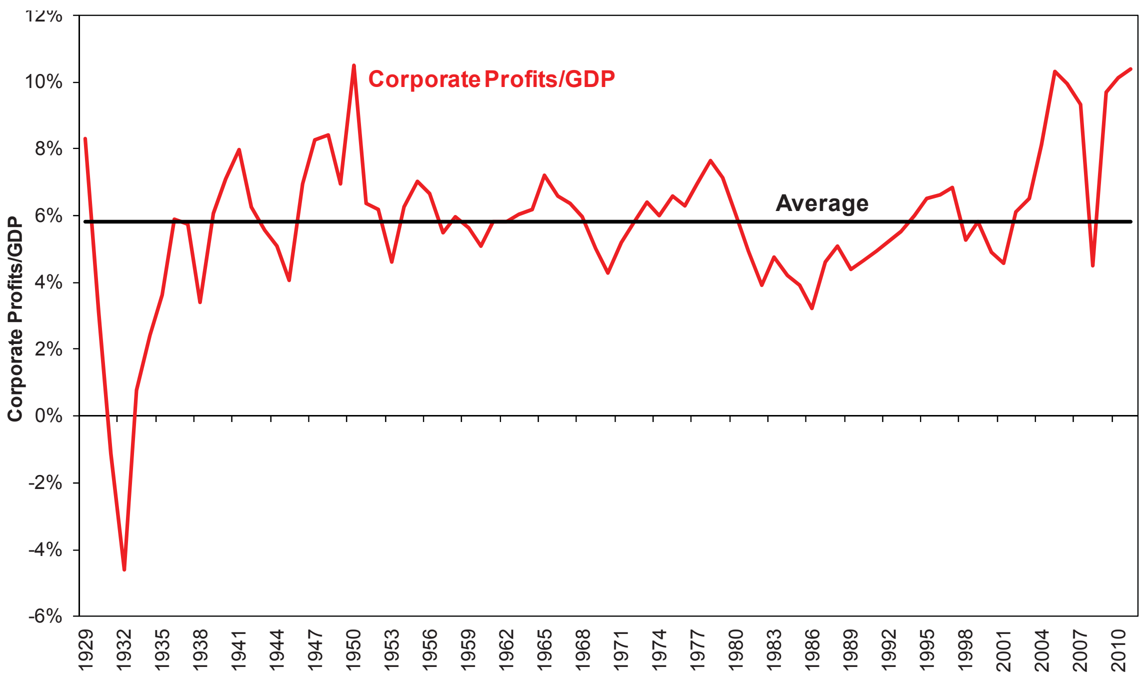
Source: S&P, Robert Shiller, GMO   As of 12/31/10

From 2000-2010, for example, the average earnings yield of the market was 5.2%, and the P/E of the market fell from 29 to 19. The P/E loss would have cost you 4.2% per year, but the compounding of that earnings yield should have allowed you to eke out 0.8% of real return over the period. The actual return was -3.2% real, which means to us that equity investors lost 4.0% relative to what they might have expected to achieve. Only in the 1920s and 1990s did investors do better than they should have had a right to expect given the earnings yield and P/E shift, and the average slippage since 1880 has been about 2.0% annually. Much of this loss came in the decade from 1910-1920, which, in addition to containing a world war and a depression, is also long enough ago that the data we have may well be somewhat suspect. If we toss out the data before the 1920s, the average slippage has been 1%.

As a result, we think equity investors should expect a real return less than the earnings yield. We build in a factor of 1% and hope it will be enough. As of June 2012, the earnings yield of the market is 6.3%, a little lower than is consistent with a return of 5.5-6.0% real. But we believe that this understates the expensiveness of equities, since profit margins today are more or less the best in history, at least on government data. Exhibit 8 shows corporate profits/GDP since 1929.

Exhibit 8

U.S. Corporate Profits vs. GDP



Source: BEA   As of 12/31/11

We have written[4] and spoken in the past about why we believe recent profit margins are unsustainable, so I will not repeat the arguments in detail here. Our basic view is that corporations have been the perhaps unintentional beneficiaries of the recent large deficits run by the U.S. and other governments. These deficits have allowed aggregate demand to hold up in a period in which corporations have been lowering wages and shedding jobs. The deficits are not sustainable, and we believe the profit margins they enable are not either. If we adjust profit margins down to a more normal level, our estimate is that the S&P 500 is priced to deliver not 5.5-6.0% real, but about 3.5%. This could possibly be the "new normal." The TIPS market shows that investors are prepared to lend money at 0.4% real for the next 30 years, and real cash rates today are around -2%, so it isn't an utterly absurd supposition that 3.5% is fair for equities. But we believe that the current economic environment, characterized by a strong desire for safety, a scramble for duration by pension funds and insurance companies, and, not least, a Federal Reserve actively working to supress long-term fixed income yields in the explicit hopes of pushing up equity prices, will not persist indefinitely. If we're right, equity investors will be in line for some capital loss as required returns wend their way back to 5.5-6.0%.

[4] See "What Goes Up Must Come Down!" by James Montier (March 2012). This white paper is available at www.gmo.com with registration.

From current levels, we believe that this loss would be around 30% – enough to reduce the returns from the S&P 500 to around 0% real if we get back to fair value in 7 years.

The internet bubble of 2000 was the worst point of overvaluation for the S&P 500 in its history. Having averaged 16 times cyclically adjusted earnings since 1881, the market soared to 44 times, well over twice normal levels. The losses and forgone returns since then have caused many investors to question whether the long-term history of equity returns is relevant any more. While this is an understandable reaction, it is the wrong one. The last 12 years have been part of an essential healing process for U.S. equities, and have brought valuations down from 44 times normal earnings to 21 times. As we analyze equity returns, this means the healing process is not yet done, and the U.S. equity market is likely to continue disappointing investors for a few years longer.

But there is a difference between expecting low returns due to reversion to long-term normal valuations and expecting low returns because something has fundamentally changed about the return-generating process for equities. Whether GDP growth in the U.S. and other developed economies is going to be slower in the future is not, in and of itself, a reason to expect a lower return to equities. Likewise, the fact that historic equity returns have been higher than GDP does not mean that the equity market has been some sort of long-term Ponzi scheme. Equities are an ugly asset class – one that is more likely than almost any other to lose investors a significant amount of money at those times when they can least afford it. That is, in a way, their charm. It is why equity is such an appealing form of capital for companies. It is the reason why equities have been priced to deliver good returns historically. And it is the reason why we believe equities are very likely to be priced to deliver strong returns into the indefinite future.

Mr. Inker is the head of asset allocation.

Attachment 6.1b

(Provided in electronic format only due to
document size and in order to conserve paper)

STANDARD & POOR'S

Global Credit Portal
RatingsDirect®

December 21, 2009

Terasen Gas Inc.

Primary Credit Analyst:
Kenton Freitag, CFA, Toronto (1) 416-507-2545; kenton_freitag@standardandpoors.com

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Major Rating Factors

Rationale

Outlook

Terasen Gas Inc.

Major Rating Factors

Strengths

- Monopoly position in its market
- Highly predictable earnings due to cost-of-service regulation
- Transparent and fair regulatory framework

Weaknesses

- Below-average financial metrics relating to high leverage

Corporate Credit Rating
A/Stable/NR

Rationale

The ratings on British Columbia-based Terasen Gas Inc. reflect Standard & Poor's Ratings Services' opinion of the company's low-risk, regulated natural gas distribution business; its sound operational record; and its free cash generation capability. We believe somewhat high leverage levels partially offset these strengths.

Terasen Gas is the primary distributor of gas in mainland B.C. It is a wholly owned subsidiary of Terasen Inc. (BBB+/Stable/--), which is itself owned by Fortis Inc. (A-/Stable/--).

In our opinion, Terasen Gas' excellent business position benefits from its monopoly status; the supportive cost of service regulation; and additional regulatory mechanisms that mitigate major operating risks, such as commodity costs. Regulatory deferral accounts and quarterly rate adjustments essentially mitigate the major risks of volatile gas commodity costs and unpredictable weather. The regulatory structure has supported very stable operating results.

Gas regulation within B.C. is well-established, and we view it as supporting credit quality. The regulator determines allowed return on equity (ROE) as a premium to long-term bond yields. This resulted in a low calculated ROE of 8.47% for 2009--which reflects, in part, the regulator's view that Terasen Gas has the lowest operating risk of all B.C. utilities. The British Columbia Utilities Commission increased Terasen Gas' 2010 ROE to 9.5%. The regulator has approved steps that Terasen has taken to insulate Terasen Gas from the parent through conditions such as dividend restrictions if Terasen Gas doesn't maintain minimum equity levels (currently at 35% but will increase to 40% in 2010).

Terasen Gas benefits from a good operational track record. It has operated one of the more efficient gas distribution networks in Canada (as measured by operating margin, operating costs per customer, and customers per employee). Despite competition from low-cost electricity, we believe Terasen Gas has good market penetration and should continue to increase its customer base (at about 1% per annum). However, the competitive advantage of natural gas compared with that of electricity can be quite volatile, because natural gas prices have experienced sharp fluctuations in the past decade. Furthermore, British Columbia's government has enacted legislation that mandated material reductions in greenhouse gas emissions by 2020. At this time, it is not clear how the act will affect natural gas usage in the province.

The company's free cash generation ability supports the rating. In the past five years, Terasen Gas has averaged more than C$80 million per year in free cash flow generation (before dividends). The company's rate base has increased moderately, standing at about C$2.5 billion, and it has targeted capital expenditures of about C$100 million per year. Given expectations of funds from operations exceeding C$180 million per year, we expect that the company's stable operations will support, on average, similar levels of free cash flow in the next few years. Nevertheless, because of the potential for gas prices to spike, Terasen Gas could occasionally encounter working-capital volatility, as it might have to defer full recovery of gas costs to smooth customer rates. The company's policy of entering preapproved contracts for gas purchases somewhat mitigates this risk--about 70% of winter gas costs are locked in through hedging and storage.

A primary operating risk for Terasen Gas is its reliance on the Spectra pipeline to source gas for its distribution network. In the event of a pipeline shutdown, the company could source gas from storage and the U.S., but it would be vulnerable to an extended pipeline shutdown. Nevertheless, we view this risk as low and acceptable at the rating level. Furthermore, the company's affiliate (Terasen Gas Vancouver Island) is proceeding with a plan to build a liquid natural gas storage on Vancouver Island, a portion of which will be available to Terasen Gas.

Terasen Gas' financial risk profile is intermediate, and below-average financial metrics constrain the ratings. Regulatory directions with respect to allowed ROE and deemed equity layers primarily influence the company's financial measures. The combination of lower equity in the capital structure and a low ROE results in elements of its financial risk profile, particularly interest coverages (funds from operations interest coverage of 2.5x) and leverage measures (debt-to-capital of 65%), that are somewhat weaker than those of higher rated U.S. peers. Partially mitigating this is Terasen Gas' consistency of free cash flow, satisfactory liquidity, and predictable financial policies.

Liquidity

Terasen Gas' liquidity is satisfactory, in our opinion.

- At Sept. 30, 2009, Terasen had C$500 million in credit lines, with C$304 million available. Bank lines support working capital volatility due to seasonality and gas price volatility.
- The company typically produces free cash flow of about C$80 million per year.
- Debt maturities are well-spread and there are none in the next few years. Terasen Gas has historically enjoyed good access to Canadian debt markets.
- Fortis, which has access to both debt and equity markets, serves as a potential temporary liquidity provider. However, Terasen Gas is a primary source of cash flow to Fortis and would not likely be able to support if its difficulties appeared permanent.

Accounting

Standard & Poor's adjusts Terasen Gas' financial statements for operating leases and pension and postretirement obligations. The adjustment includes adding a debt equivalent, interest expense, and depreciation to the company's reported financial statements. As a result, we add debt equivalents of C$107 million for Terasen Gas' operating leases and C$59 million for pension and postretirement obligations.

Due to the distortions in leverage and cash flow metrics that the substantial seasonal working-capital requirements of gas utilities cause, Standard & Poor's adjusts Terasen Gas' inventory and debt balances by netting the value of inventory against the short-term debt outstanding. This adjustment provides a more accurate view of the company's financial performance by reducing seasonality where there is a very high likelihood of recovery. As inventories are depleted and accounts receivable are monetized with support from commodity pass-through mechanisms, these funds reduce the utility's short-term borrowings.

Outlook

The stable outlook reflects Standard & Poor's expectation of steady operating performance. Given that a significant improvement in its capital structure appears remote, an upgrade or outlook revision to positive is unlikely. A negative outlook or downgrade could result from operational difficulties or a decision to increase leverage.

Table 1

Terasen Gas Inc.--Peer Comparison*

Industry Sector: Gas

	--Average of past three fiscal years--		
(Mil. C$)	**Terasen Gas Inc.**	**Enbridge Gas Distribution Inc.**	**Gaz Metro L.P.**
Rating as of Dec. 21, 2009	A/Stable/--	A-/Stable/--	A-/Stable/--
Revenues	1,571.5	3,025.0	2,123.4
Net income from continuing operations	79.4	176.2	145.2
Funds from operations (FFO)	167.5	395.5	400.4
Capital expenditures	77.9	392.3	138.1
Cash and short-term investments	8.4	33.3	34.7
Debt	1,599.0	2,820.8	1,888.4
Preferred stock	0.0	50.0	0.0
Equity	858.0	1,752.4	824.7
Debt and equity	2,457.0	4,573.2	2,713.1
Adjusted ratios			
EBIT interest coverage (x)	2.0	2.0	2.2
FFO interest coverage (x)	2.4	2.8	4.4
FFO/debt (%)	10.5	14.0	21.2
Discretionary cash flow/debt (%)	2.2	(2.4)	7.1
Net cash flow/capex (%)	107.8	66.4	182.0
Total debt/debt plus equity (%)	65.1	61.7	69.6
Return on common equity (%)	8.9	9.8	15.6
Common dividend payout ratio (unadjusted; %)	105.4	77.3	102.6

*Fully adjusted (including postretirement obligations).

Table 2

Terasen Gas Inc.--Financial Summary*

Industry Sector: Gas

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2008**	**2007**	**2006**	**2005**	**2004**
Rating history	A/Stable/--	A/Stable/--	BBB/Watch Neg/--	BBB/Negative/--	BBB/Stable/--
Revenues	1,664.6	1,524.6	1,525.3	1,465.9	1,305.2
Net income from continuing operations	91.5	78.2	68.4	65.3	70.8
Funds from operations (FFO)	173.0	152.9	176.7	160.8	159.6
Capital expenditures	121.1	4.5	108.0	153.7	118.4
Cash and short-term investments	13.1	5.6	6.5	15.6	1.7

Table 2

Terasen Gas Inc.--Financial Summary* (cont.)					
Debt	1,613.6	1,620.2	1,563.2	1,671.7	1,583.1
Equity	839.7	856.6	877.7	813.1	783.7
Debt and equity	2,453.3	2,476.8	2,440.9	2,484.9	2,366.7
Adjusted ratios					
EBIT interest coverage (x)	1.9	2.0	2.0	1.9	2.0
FFO interest coverage (x)	2.4	2.2	2.5	2.3	2.3
FFO/debt (%)	10.7	9.4	11.3	9.6	10.1
Discretionary cash flow/debt (%)	(0.9)	0.6	7.2	(5.8)	1.3
Net cash flow/capex (%)	60.2	943.0	126.6	65.6	84.1
Debt/debt and equity (%)	65.8	65.4	64.0	67.3	66.9
Return on common equity (%)	10.3	8.7	7.7	7.8	8.9
Common dividend payout ratio (unadjusted; %)	109.3	141.8	58.5	91.9	84.7

*Fully adjusted (including postretirement obligations).

Table 3

Reconciliation Of Terasen Gas Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)*									
	--Fiscal year ended Dec. 31, 2008--								
Terasen Gas Inc. reported amounts	**Debt**	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Capital expenditures**
Reported	1,640.2	875.0	291.9	291.9	213.6	110.4	198.5	198.5	122.1
Standard & Poor's adjustments									
Operating leases	107.1	N/A	15.6	7.6	7.6	7.6	7.9	7.9	N/A
Postretirement benefit obligations	58.6	(35.3)	2.1	2.1	2.1	N/A	0.8	0.8	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	1.0	(1.0)	(1.0)	(1.0)
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(33.3)	N/A
Other	(192.3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	(26.6)	(35.3)	17.7	9.7	9.7	8.6	7.8	(25.5)	(1.0)
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Operating income (before D&A)**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Capital expenditures**
Adjusted	1,613.6	839.7	309.6	301.6	223.3	119.0	206.3	173.0	121.1

*Terasen Gas Inc. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts. D&A--Depreciation and amortization. N/A--Not applicable.

Ratings Detail (As Of December 21, 2009)*	
Terasen Gas Inc.	
Corporate Credit Rating	A/Stable/NR
Senior Secured (2 Issues)	AA-
Corporate Credit Ratings History	
19-Jun-2007	A/Stable/NR
26-Feb-2007	BBB/Watch Pos/NR
30-May-2006	BBB/Watch Neg/NR
06-Dec-2005	BBB/Negative/NR
02-Aug-2005	BBB/Watch Neg/NR
Business Risk Profile	Excellent
Financial Risk Profile	Intermediate
Related Entities	
Caribbean Utilities Co. Ltd.	
Issuer Credit Rating	A/Negative/--
Senior Unsecured (8 Issues)	A
Cortez Capital Corp.	
Issuer Credit Rating	--/--/A-3
FortisAlberta Inc.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured (8 Issues)	A-
Fortis Inc.	
Issuer Credit Rating	A-/Stable/--
Preferred Stock (2 Issues)	BBB
Canadian Preferred Stock Rating (2 Issues)	P-2
Senior Unsecured (1 Issue)	A-
Kinder Morgan Energy Partners L.P.	
Issuer Credit Rating	
Foreign Currency	BBB/Negative/--
Local Currency	BBB/Negative/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured (19 Issues)	BBB
Kinder Morgan G.P. Inc.	
Preferred Stock (1 Issue)	BB+
Kinder Morgan Inc.	
Issuer Credit Rating	BB/Stable/NR
Preferred Stock (5 Issues)	B
Senior Secured (10 Issues)	BB
Maritime Electric Co. Ltd.	
Issuer Credit Rating	BBB+/Stable/--
Senior Secured (7 Issues)	A
Terasen Inc.	
Issuer Credit Rating	BBB+/Stable/NR

Ratings Detail (As Of December 21, 2009)* (cont.)	
Senior Unsecured (1 Issue)	BBB+
Subordinated (1 Issue)	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.

Rating Report

Report Date:
May 27, 2009

Previous Report
May 20, 2008

Terasen Gas Inc.

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The Company

Terasen Gas Inc. (TGI or the Company) is the largest natural gas distributor in British Columbia, serving approximately 834,000 customers, representing 90% of the province's natural gas users. The Company is 100% owned by Terasen Inc. (rated BBB (high)), which is a wholly-owned subsidiary of Fortis Inc. (rated BBB (high)). The ratings assigned to TGI are based predominantly on a stand-alone basis.

Recent Actions

February 20, 2009
Rates New Issue

May 13, 2008
Rates New Issue

April 14, 2008
Confirmed with a Stable Trend

Rating

Debt	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
MTNs & Unsecured Debentures	A	Confirmed	Stable

Rating Update

DBRS has confirmed the Purchase Money Mortgages and the MTNs & Unsecured Debentures ratings of Terasen Gas Inc. (TGI or the Company) at "A" and its Commercial Paper rating at R-1 (low), all with Stable trends. The rating confirmations reflect TGI's low business risk natural gas distribution operations, a favourable regulatory environment with strong ring-fencing provisions, a strong franchise area with a large customer base and a stable financial profile.

The regulatory environment continues to remain stable, and provides for a number of cost-recovery mechanisms which, when combined with the rate-setting methodology, allows for a full recovery of all prudently incurred operating expenses and capital expenditures within a reasonable time frame. The Company's performance based regulation (PBR), which had been in place from 2004 to 2007, was extended through to 2009. TGI recently filed an application to review its allowed return on equity (ROE) and capital structure, and is expected to file a new revenue requirement application with the continuation of its numerous deferral accounts. Although the ROE has been in general decline (8.47% in 2009 as opposed to 9.42% in 2003) because of the low interest rate environment, the impact on earnings and cash flow has been modest and is largely offset by increases in the rate base, higher approved equity thickness in the capital structure (35% since 2006, up from 33% previously), incentive earnings, and stable levels of debt.

TGI continues to maintain a stable financial profile and credit metrics (albeit weaker than its peers), reflecting the regulated nature of its operations and its limited gas-cost exposure. DBRS expects lower customer growth than in the past few years due to a slowing economy, fewer new housing starts, and a shift in the housing mix to more multi-family dwellings. TGI is expected to focus on retaining customers through expanded energy conservation and efficiency programs. (Continued on page 2.)

Rating Considerations

Strengths

(1) Low business risk and supportive regulatory framework
(2) Strong regulatory ring-fencing provisions
(3) Reasonable balance sheet and stable credit metrics
(4) Strong franchise area with a large customer base

Challenges

(1) Earnings and cash flow affected by lower ROE
(2) Long-term competitiveness of natural gas relative to alternative energy sources
(3) Volume exposure in the industrial and transportation segment
(4) Loss of PBR incentive earnings upon expiry

Financial Information

	12 mos. ended Mar. 31 '09	For the year ended December 31			
	2009	2008	2007	2006	2005
EBIT interest coverage (1)	1.89	1.88	1.95	2.00	1.94
% debt in capital structure (1)	63.6%	66.4%	66.5%	64.7%	67.6%
Cash flow/total debt (times) (1)	9.6%	8.8%	8.4%	9.7%	8.9%
Cash flow/capital expenditures (times)	1.21	1.24	1.35	1.47	1.52
Net income bef. extras (CAD millions)	79	78	70	68	70
Operating cash flow (CAD millions)	151	152	146	160	157

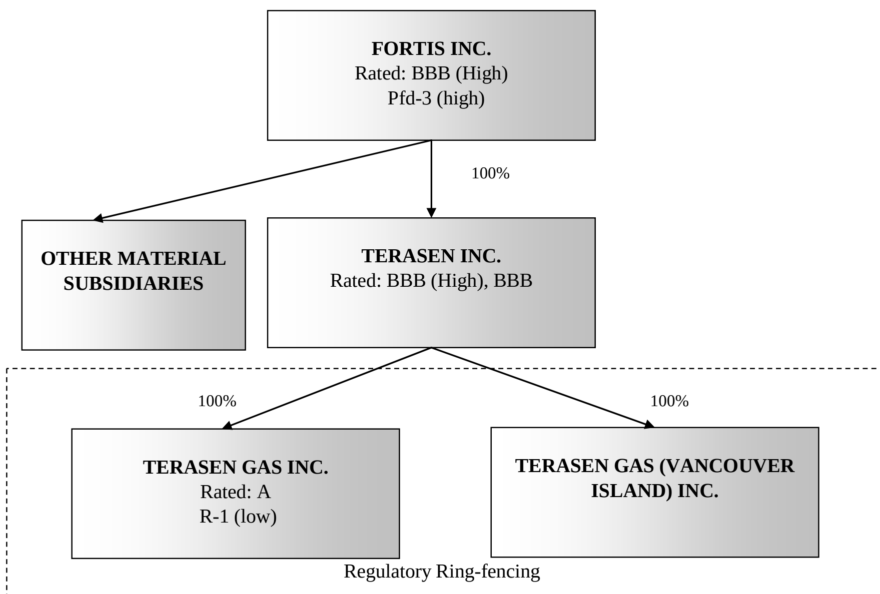
(1) Includes operating leases

Rating Update (Continued from page 1.)

Minimal to modest free cash flow deficits are expected over the medium term, attributable to the replacement and refurbishment of existing infrastructure (which is expected to go into the rate base in a timely manner) and modest customer growth. Any deficits would be expected to be financed with a combination of the $500 million revolving bank facility ($389 million available at March 31, 2009) and long-term debt issuance. TGI's balance sheet should remain stable over the medium term as the Company is expected to manage its dividends to maintain its capital structure within the regulatory-approved debt-to-equity ratio of 65% to 35%.

The Company's credit metrics have historically remained consistent and are expected to continue to do so, with minor variability. DBRS notes that while TGI's credit metrics are weaker than those of similarly-rated gas distribution peers, this has historically been offset by the Company's more stable credit metrics and business risk profile. The Company continues to maintain a price advantage relative to electricity, the primary competitor to natural gas. The current weak gas pricing environment both improves TGI's competitiveness, and reduces working capital and liquidity requirements. TGI's financial strength and credit profile over the longer term will depend to an extent on the continued competitiveness of natural gas relative to alternative energy sources (mainly electricity).

Simplified TGI Ownership and Rating Chart



Rating Considerations Details

Strengths

(1) TGI benefits from having all its operations in a low-risk, stable regulated environment within a supportive regulatory framework. TGI operates under a full cost-of-service recovery regime, with deferral accounts existing to stabilize earnings and to adjust for the recovery/refund of shortfalls/overages of natural gas costs from/to customers. TGI has no exposure to commodity costs (subject to a recovery lag) as natural gas costs are fully passed on to customers, with quarterly adjustments.

(2) Regulatory ring-fencing conditions imposed on TGI in the April 30, 2007, British Columbia Utilities Commission (BCUC) order approving acquisition of Terasen Inc. by Fortis Inc. are viewed as positive for TGI's credit profile, offering protection from significant changes in its capital structure.

(3) TGI maintains a stable balance sheet and credit metrics, reflecting the following: (a) a debt-to-capital ratio consistently in the mid-60% area; (b) an EBIT interest coverage ratio historically close to 2.0 times; and (c) a cash flow-to-debt ratio that has been in the 8% to 10% range over the past five years. While the EBIT coverage and cash flow-to-debt ratios are on the low end for an "A" rating compared with its gas distribution peers, historically TGI's credit metrics have shown the most stability.

(4) TGI serves a large customer base of approximately 834,000, located in a stable franchise area that includes the city of Vancouver. The customer mix is favourable, with residential and commercial customers accounting for 90% of distribution revenues. There is no volume risk (but recovery lag exists) associated with this customer segment.

Challenges
(1) The approved ROE of 8.47% for 2009 (8.62% in 2008) is low and has been in gradual decline in recent years due to the low interest rate environment. Despite a modestly growing rate base ($2.5 billion in 2008 compared with $2.3 billion in 2004), earnings and cash flow have remained flat, largely as a result of the lower ROE. Under the current adjustment mechanism, approved ROEs could trend even lower in the future, depending on Government of Canada bond (Canada Bonds) yields.

(2) TGI's earnings and financial profile over the longer term will largely depend on the competitive position of natural gas relative to alternative energy sources (mainly electricity) in British Columbia. Despite the significant increases in natural gas prices from 1999 through 2008, natural gas maintained a competitive advantage in terms of pricing compared with electricity. While gas prices have retreated significantly in 2009, it is expected that under reasonable gas price assumptions, TGI will remain competitive relative to electricity, with electricity prices expected to rise gradually in the medium term, according to BC Hydro.

(3) The Company is exposed to variances from forecasts when it comes to its industrial fixed-price contracts and transportation-services segments, which represent approximately 45% of throughput volumes (5% of revenues). However, this exposure is mitigated by the fact that their usage is less likely to be significantly affected by weather and is therefore more predictable. TGI conducts an annual survey of its industrial customer segment to minimize forecast variances in throughput volumes. Further mitigating this risk is the fixed demand charges derived from this segment.

(4) Under the PBR, TGI shares earnings above or below the allowed ROE on a 50/50 basis with customers. This sharing mechanism will expire along with the PBR, which will likely exert some downward pressure on earnings, as TGI's incentive earnings averaged over $10 million per year in 2007 and 2008.

Regulation

Regulatory Overview

- TGI is regulated by the BCUC on a test-year forecast basis under a rate-of-return/cost-of-service regime. TGI applies to the BCUC annually for approval of its forecast cost-of-service, throughput, revenue and capital additions.
- TGI's cost of service includes the cost of purchased gas and the cost of gas transportation and distribution through the pipeline system, including operating, maintenance and administrative expenses (OM&A); depreciation of facilities; income and other taxes; and a return on equity.
- TGI purchases gas for resale, without markup, to residential and commercial customers; transportation customers and some large commercial and industrial customers arrange for their own gas supply and contract with TGI for the transportation of that gas.
- TGI's rates are based on estimates of several items, such as natural gas sales volumes, cost of natural gas and interest rates. In order to manage the risks associated with some of these estimates, a number of regulatory deferral accounts are in place.
  - **Commodity Cost Reconciliation Account and Midstream Cost Reconciliation Account:** The differences between actual and forecast gas costs are recorded in these deferral accounts to be recovered or refunded in future rates. This exposes TGI to a recovery lag (the balances are anticipated to be fully recovered or refunded within the next fiscal year), but price adjustments in the price forecast are made on a quarterly basis to better reflect prevailing gas commodity prices. This mitigates the impact of recovery lag.

- **Revenue Stabilization Adjustment Account (RSAM):** The RSAM seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use throughout the year. The RSAM account is anticipated to be recovered in rates over three years (for comparison, in Ontario, gas distribution companies are exposed to volume risk, which can be significant due to changes in the weather). Variances in usage by large-volume industrial transportation and sales customers, which account for 45% of total throughput, are not covered by this deferral account. However, their usage is more predictable and less likely to be significantly affected by weather.
- TGI also has in place short- and long-term interest rate deferral accounts to absorb interest rate fluctuations.

• Variances between forecast and actual cost of service and revenue are generally approved by the BCUC for recovery in future rates, with the exception of excess OM&A costs and base-capital expenditures, which are subject to an incentive formula.
- In 2003, the BCUC approved a negotiated settlement of a performance-based rate (PBR) plan covering the 2004 to 2007 period. In 2007, the BCUC approved a TGI application to extend the PBR through 2009.
- Under the PBR plan, operating and maintenance costs and base-capital expenditures are subject to an incentive formula that reflects increasing costs as a result of customer growth and inflation less a productivity factor equal to 50% of inflation during the first two years of the plan and 66% of inflation during 2006 and 2007.
- The PBR plan provides for a 50-50 sharing mechanism of earnings above or below the allowed ROE.
- Allowed ROE is set annually according to a formula based on a forecast of 30-year Canada Bonds plus a 3.90% risk premium when the forecast yield is 5.25%. The risk premium is adjusted annually by 75% of the difference between 5.25% and the forecast yield. Based on this formula, for F2009, the ROE is set at 8.47% (8.62% in 2008), with an equity thickness of 35%. The equity thickness was increased to 35% from 33% in 2006.

• Declining yields on 30-year Canada Bonds have reduced approved ROEs (and could continue to do so), which, when coupled with increased credit spreads on long-term debt offerings, has resulted in a declining spread between approved ROEs and debt costs. The Company recently filed an application with the BCUC seeking changes to the current generic ROE adjustment mechanism and deemed equity thickness; TGI requested that its ROE be set at 11% (and not be adjusted by an automatic mechanism) and its equity thickness increased to 40%.
• Forecast capital expenditures are also approved by the BCUC. For capital projects that are not covered by the annual capital plan or PBR, TGI submits a separate application to the BCUC. If actual capital costs exceed the amount approved, the excess cost may be subject to a prudence review.

Regulatory Ring-Fencing

A summary of the regulatory ring-fencing conditions in the April 30, 2007, BCUC order imposed on TGI approving the Fortis Inc. acquisition of Terasen Inc. is as follows:

• TGI must maintain the equity in the capital structure at least at the deemed equity level approved by the BCUC (35%).
• TGI must obtain approval from the BCUC before paying dividends to its parent if the paying of dividends can be reasonably expected to increase leverage above the approved level.
• The Company will not be allowed to lend to, guarantee or financially support any affiliates of Terasen Inc. or its non-regulated businesses.
• TGI will not be allowed to enter a tax-sharing agreement with any of its affiliates unless the agreement has been approved by the BCUC.
• TGI must maintain the continued independence of directors.

Earnings and Outlook

Consolidated Earnings

(CAD millions)	12 mos. ended Mar. 31 '09 2009	For the year ended December 31 2008	2007	2006	2005
Net revenues	517	513	507	517	505
EBITDA	291	292	293	301	302
EBIT	211	214	215	217	222
Gross interest expense	112	111	108	106	112
Pre-tax income	101	103	108	112	111
Income taxes	22	25	38	44	42
Net income (before extras)	79	78	70	68	70
Net income	92	92	78	68	65
Return on avg. common equity (bef. extras.)	8.8%	8.9%	7.9%	7.8%	8.4%
EBIT margin (net of gas costs)	40.9%	41.7%	42.3%	42.0%	44.1%
Rate Base	n/a	2,510	2,484	2,516	2,406
Approved common equity	35.0%	35.0%	35.0%	35.0%	33.0%
Allowed ROE	8.47%*	8.62%	8.37%	8.80%	9.03%

* 8.47% for 2009

Summary

- TGI has historically demonstrated very stable levels of EBITDA and EBIT, reflective of modest net additions to its customer base, increases in its rate base and a stable approved equity component, all largely offset by declining allowed ROE.
  - Earnings volatility is further reduced due to the customer breakdown, with residential and commercial customers providing the majority of its margin and industrial customers normally under contract.
- Though in recent years housing starts in British Columbia have been strong, growth in multi-family housing continues to have an impact on net additions as natural gas is less prevalent in this type of dwelling. The BCUC’s 2006 decision to increase TGI’s equity thickness to 35% from 33% had a positive impact on TGI’s performance.
- The gas distribution segment (residential and commercial customers) has historically accounted for more than 50% of total throughput volumes and 90% of total revenues. Throughputs for this segment have exhibited stability over the past five years, and volume risk is mitigated as shortfalls/overages in volume revenues are deferred and recovered/refunded through future rates.
- The transportation segment and industrial customers under fixed-price contracts have historically accounted for approximately 50% of total throughput volumes and less than 10% of total revenues. Although transportation and industrial customer segments are exposed to volume risk, it is mitigated by the fact that their usage is less likely to be significantly affected by weather and is therefore more predictable. Further mitigating this risk is the fixed demand charges derived from these segments.
- Interest expense has been relatively stable over the past five years due to fairly consistent levels of total debt.

Outlook

- In the shorter term, earnings will likely be moderately impacted by the loss of incentive earnings upon expiry of the PBR mechanism. Over the medium term, as a mature gas distribution utility, TGI is expected to have relatively stable earnings with some variability due to allowed ROE, population growth, new housing starts and customer conversions. DBRS expects lower customer growth than in the past few years due to a slowing economy and fewer new housing starts. TGI is expected to focus on retaining customers through expanded energy conservation and efficiency programs.
- Over the longer term, earnings will largely depend on the competitiveness of natural gas relative to electricity in British Columbia. While TGI has maintained a competitive advantage in terms of pricing compared with electricity, its competitive position would weaken should gas prices increase significantly for a prolonged period of time, potentially having a negative impact on TGI’s financial and credit profile. The competitiveness of natural gas will also be affected by the provincial consumption tax on carbon-based fuels.

Financial Profile

(CAD millions)	12 mos. ended Mar. 31 '09 2009	For year ended Dec. 31 2008	2007	2006	2005
Net income before extraordinary items	79	78	70	68	70
Depreciaton & amortization	79	78	79	84	79
Other non-cash adjustments	(7)	(5)	(3)	8	8
Cash Flow From Operations	151	152	146	160	157
Capital expenditures	(125)	(122)	(108)	(109)	(103)
Common dividends	(58)	(100)	(111)	(40)	(60)
Free Cash Flow Before W/C Changes	(32)	(70)	(73)	12	(7)
Working capital changes	25	33	(28)	83	(45)
Net Free Cash Flow	(7)	(37)	(101)	95	(51)
Acquisitions/divestitures	0	14	0	0	(42)
Other adjustment/comprehensive	38	36	11	(7)	(2)
Cash flow before financing	31	13	(90)	88	(95)
Net change in debt financing	(23)	(5)	89	(98)	109
Net change in pref. share financing	0	0	0	0	0
Net change in equity financing	0	0	0	0	0
Net Change in Cash	8	8	(1)	(9)	14
Total adjusted debt (CAD million) (1)	1,569	1,730	1,744	1,655	1,763
Cash flow/total debt (times) (1)	9.6%	8.8%	8.4%	9.7%	8.9%
% debt in the capital structure (1)	63.6%	66.4%	66.5%	64.7%	67.6%
EBIT interest coverage (times)	1.89	1.88	1.95	2.00	1.94
Dividend payout ratio (%)	73.2%	127.7%	158.0%	58.5%	86.3%

(1) Includes operating leases

Summary

- TGI continues to maintain stable cash flow from operations, which historically has been largely adequate to fund both capital expenditure and dividend payments.
- The relatively large dividend payments in F2007 and F2008 were primarily due to the significant reduction in dividend payment in F2006.
  - Dividend payments in F2006 were modest as TGI, through retained earnings, increased its equity thickness from 33% to the new regulatory-approved 35%. Going forward, DBRS expects that dividend payments will be made in such a way as to keep the Company's debt-to-capital in line with that allowed by the regulator.
  - As part of the ring-fencing condition, TGI is prohibited from paying dividends unless it has in place at least as much equity as required by the BCUC for rate-making purposes. As such, free cash flow has varied along with the level of dividend payments in recent years. Free cash flow deficits over the past five years have been manageable and were funded with debt.
- Leverage remains reasonable at approximately 66%, offset by a weak but acceptable cash flow-to-debt ratio, which is typically in the 8% to 10% range. The stability of TGI's credit metrics is a key factor in its current ratings.

Outlook

- Minimal to modest free cash flow deficits are expected over the medium term, attributable to the replacement and refurbishment of existing infrastructure and modest customer growth. Any deficits are expected to be financed with a combination of TGI's $500 million revolving bank facility ($218 million available at December 31, 2008) and long-term debt issuance.
  - DBRS expects the capital expenditure to be approximately $150 million (before customer contributions) annually over the medium term, with maintenance capital expenditure expected to account for approximately 70% to 80% of the total.
- TGI's financial profile should remain relatively stable over the medium term as the Company is expected to manage its dividends to maintain its capital structure within the regulatory-approved 65% to 35% debt-to-equity (unchanged from 2008).
- Longer term, under reasonable gas and electricity price assumptions, it is expected that TGI will remain competitive relative to alternative energy sources.

Long-Term Debt Maturities and Liquidity

As at Dec. 31, 2008 (CAD millions)	2009	2010	2011	2012	2013	Thereafter	Total
Long-Term Debt	62	2	2	2	2	1,345	1,413

- Currently, TGI has a five-year, $500 million unsecured committed revolving credit facility with a syndicate of banks that matures in August 2013. Approximately $389 million was unutilized at March 31, 2009. The credit facility is used to support TGI's $500 million commercial paper (CP) program and working capital requirements, which vary to a large extent with seasonal gas inventory levels. Gas inventory levels and working capital requirements (and, therefore, short-term debt) typically peak in the fall and winter seasons, with reductions in the spring and summer.
- The debt-repayment schedule is very modest through to 2015. In February 2009, TGI issued $100 million of 30-year notes, which more than pre-funds the 2009 maturities.
- TGI's bond indenture contains an EBIT-to-interest coverage test in order to issue additional indebtedness. EBIT for 12 consecutive months out of the previous 23 months must be at least 2.0 times its annual pro forma interest requirements for debt that has a maturity term longer than 18 months.
  - The covenant does not apply to debt issuance for refinancing, and interest expenses do not include interest expenses related to short-term debt or Purchase Money Mortgages.

Terasen Gas Inc.

Report Date:
May 27, 2009

Terasen Gas Inc.

Balance Sheet
(CAD millions)

Assets	Mar. 31 2009	As at December 31 2008	2007	**Liabilities & Equity**	Mar. 31 2009	As at December 31 2008	2007
Cash	17	13	6	Short-term debt	68	239	305
Accounts receivable	388	346	310	L.t.d. due in one year	62	62	190
Inventories	64	192	187	A/P	371	366	331
Prepaid expenses	27	3	4	Tax payables	62	66	39
Rate stabilization accts	116	54	61	Rate stabilization acct.	55	24	0
Current Assets	613	608	568	**Current Liabilities**	617	755	865
Net fixed assets	2,369	2,432	2,380	Long-term debt	1,439	1,340	1,151
Rate stabilization accts	0	0	12	Deferred credits	183	138	78
Deferred charges	305	0	40	Deferred taxes	249	1	51
Long-term rec. + investments	101	69	23	Shareholders' equity	900	875	878
Total	3,387	3,109	3,022	**Total**	3,387	3,109	3,022

Ratio Analysis	12 mos. ending Mar. 31/09	For the year ended December 31			
Liquidity Ratios	2009	2008	2007	2006	2005
Current ratio	0.99	0.80	0.66	0.65	0.74
Accumulated depreciation/gross fixed assets	n/a	23.8%	23.4%	23.5%	21.9%
Cash flow/total debt (1)	9.6%	8.8%	8.4%	9.7%	8.9%
Cash flow/capital expenditure	1.21	1.24	1.35	1.47	1.52
Cash flow-dividends/capital expenditures	0.75	0.43	0.33	1.11	0.94
% debt in capital structure (1)	63.6%	66.4%	66.5%	64.7%	67.6%
Approved common equity	35%	35%	35%	35%	33%
Common dividend payout (before extras.)	73.2%	127.7%	158.0%	58.5%	86.3%
Coverage Ratios					
EBIT interest coverage (1)	1.89	1.88	1.95	2.00	1.94
EBITDA interest coverage (1)	2.61	2.55	2.64	2.84	2.70
Fixed-charges coverage (1)	1.89	1.84	1.90	1.95	1.90
Debt/EBITDA	5.40	5.93	5.95	5.50	5.85
Earnings Quality					
EBIT margin, excluding cost of natural gas	40.9%	41.7%	42.3%	42.0%	44.1%
Net margin (excluding preferred dividends)	15.2%	15.3%	13.8%	13.2%	13.8%
Return on avg. common equity (bef. extras.)	8.85%	8.93%	7.89%	7.8%	8.4%
Allowed ROE	8.47%*	8.62%	8.37%	8.80%	9.03%
Operating Statistics					
Customers/employees	n/a	758	750	679	671
Customer growth	n/a	1.1%	1.2%	1.3%	1.6%
Operating costs/avg. customer (CAD)	n/a	306	303	318	304
Rate base (CAD millions)	n/a	2,510	2,484	2,516	2,406
Rate base growth	n/a	1.0%	-1.3%	4.6%	4.2%

(1) Includes operating leases

* 8.47% for 2009

Operating Statistics

	For year ended December 31				
Throughput Volumes	2008	2007	2006	2005	2004
Residential	78.5	74.9	68.7	69.4	66.5
Commercial	44.1	42.3	38.4	39.1	38.3
Small industrial	3.1	3.4	3.8	4.2	4.9
Large industrial	0.1	0.2	0.2	0.3	0.4
Total Natural Gas Sales Volumes	125.8	120.8	111.1	113.0	110.1
Transportation service	57.3	62.3	62.3	63.9	0.0
Throughput under fixed-price contracts	39.6	36.8	36.8	36.4	0.0
Total Throughputs (PJs)	222.7	219.9	210.2	213.3	110.1
Customers					
Residential	750,838	742,882	733,598	723,898	712,304
Commercial	81,012	79,717	79,113	78,497	77,624
Small industrial	284	297	325	396	416
Large industrial	33	40	40	45	45
Transportation	2,059	2,041	1,956	1,907	1,741
Total (thousands)	834,226	824,977	815,032	804,743	792,130

Terasen Gas Inc.

Report Date:
May 27, 2009

Ratings

Debt Rated	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	table
MTNs & Unsecured Debentures	A	Confirmed	Stable

Rating History

Debt Rated	Current	2008	2007	2006	2005	2004
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Purchase Money Mortgages	A	A	A	A	A	A
MTNs & Unsecured Debentures	A	A	A	A	A	A

Note:
All figures are in Canadian dollars unless otherwise noted.

MOODY'S
INVESTORS SERVICE

Credit Opinion: Terasen Gas Inc.

Global Credit Research - 28 May 2010

Vancouver, British Columbia, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Secured -Dom Curr	A1
Senior Unsecured -Dom Curr	A3
Parent: Terasen Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa2
Subordinate -Dom Curr	Baa3
Terasen Gas (Vancouver Island) Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3

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Key Indicators

[1]**Terasen Gas Inc.**

	[2]**LTM**	**2009**	**2008**	**2007**	**2006**	**2005**
(CFO Pre-WC + Interest) / Interest Expense	**2.7x**	**2.6x**	**2.5x**	**2.4x**	**2.5x**	**2.4x**
(CFO Pre-WC) / Debt	**12.2%**	**10.3%**	**9.8%**	**8.8%**	**10.1%**	**9.0%**
(CFO Pre-WC - Dividends) / Debt	**7.6%**	**6.5%**	**4.2%**	**2.5%**	**7.7%**	**5.7%**
Debt / Book Capitalization	**55.9%**	**61.7%**	**68.4%**	**66.8%**	**65.2%**	**68.7%**

[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 March 31, 2010

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low-risk, cost of service regulated gas transmission and distribution utility with no unregulated operations.

Relatively weak financial metrics partially offset by a supportive regulatory environment.

Strong regulatory ring-fencing mechanisms.

Corporate Profile

Terasen Gas Inc. (TGI) is the largest distributor of natural gas in British Columbia and the third largest gas distribution utility in Canada. TGI is regulated on a cost of service basis by the British Columbia Utilities Commission (BCUC).

TGI is a wholly-owned subsidiary of Terasen Inc. (TER) which, in turn, is a wholly-owned subsidiary of Fortis Inc. (FTS), a diversified electric and gas utility holding company. TER is a holding company which also holds 100% of Terasen Gas (Vancouver Island) Inc. (TGVI) and Terasen Gas (Whistler) Inc. (TGW) as well as a 30% interest in CustomerWorks, L.P.

SUMMARY RATING RATIONALE

TGI's A3 senior unsecured rating and stable outlook reflect its low-risk business model and supportive regulatory environment which partially offset its weak financial metrics. Moody's recognizes that the weakness of TGI's financial metrics relative to similarly rated U.S. peers is largely a function of the relatively lower deemed equity and allowed ROE permitted by the BCUC. We believe that TGI's weak financial profile is offset to a significant degree by the supportiveness of the business and regulatory environments in Canada generally and in British Columbia specifically.

TGI's financial profile is expected to strengthen modestly in 2010 due to the BCUC's December 2009 cost of capital decision which increased TGI's allowed ROE to 9.5% and its deemed equity to 40%. Regulatory ring-fencing mechanisms effectively insulate TGI from its weaker parent companies, TER and FTS. Growth in TGI's franchise area tends to be predictable and capital spending is not expected to tax the company's resources. TGI enjoys good access to the term debt markets and maintains liquidity resources that are sufficient.

TGI's A3 rating is consistent with the A3 rating implied by our Regulated Electric and Gas Utility Rating Methodology.

DETAILED RATING CONSIDERATIONS

LOW-RISK REGULATED GAS DISTRIBUTION UTILITY OPERATING IN A SUPPORTIVE ENVIRONMENT

In general, we consider gas local distribution companies (LDC) to be at the low end of the risk spectrum within the universe of regulated utilities. Similarly, we believe that regulated utilities, which are permitted the opportunity to recover their costs and earn an allowed return, have lower business risk than unregulated companies that do not benefit from cost of service regulation. Accordingly, we consider regulated gas LDCs like TGI to be among the lowest risk corporate entities.

The company's location in British Columbia, which until recently enjoyed a relatively strong provincial economy and continues to enjoy a supportive regulatory climate, contributes to our view of TGI as a relatively low-risk regulated gas distribution company. We consider Canada to have more supportive regulatory and business environments than other jurisdictions globally. Furthermore, the regulatory environment in the Province of British Columbia is considered one of the most supportive in Canada reflecting the fact that regulatory proceedings tend to be less adversarial and decisions tend to be timely and balanced. The supportiveness of the British Columbia regulatory environment is also evidenced by the fact that TGI benefits from the existence of a number of BCUC-approved deferral, or true up, mechanisms. These mechanisms limit TGI's exposure to forecast error with respect to commodity price and volume, pension funding costs, insurance costs and short-term interest rates. In addition, on an annual basis TGI reviews its capital spending plans, and the rate impacts thereof, with the BCUC. In our view, this process substantially reduces the risk that TGI might be unable to fully recover its capital investments. In our view, these factors more than offset the fact that deemed equity thicknesses and allowed ROEs in Canada tend to be lower than those in the U.S.

Growth in TGI's franchise area tends to be relatively predictable and capital spending is generally stable and modest in the context of TGI's asset base and depreciation expense. That said, we expect capital spending to be higher in 2010 and 2011 than it has been in recent years. This reflects certain non-recurring or infrequently occuring projects such as the development of a new customer care system and the upgrading of a major river crossing. Notwithstanding higher capital spending in 2010 and 2011, we anticipate that TGI will continue to finance capital spending with a prudent combination of internally generated funds and additional term debt.

FINANCIAL METRICS EXPECTED TO STRENGTHEN MODESTLY IN 2010

TGI's financial metrics are materially weaker than those of its A3 rated global gas utility peers such as Piedmont Natural Gas Company, Inc., Northwest Natural Gas Company, UGI Utilities and its sister company, TGVI. We recognize that TGI's weaker financial metrics are largely a function of the deemed equity and allowed ROE approved by the BCUC. In general, Canadian deemed equity ratios and allowed ROEs are low relative to those of other jurisdictions and historically TGI's were among the lowest in Canada.

However, the BCUC's December 2009 cost of capital decision is expected to have a small positive impact on TGI's financial metrics. In that decision, TGI's allowed ROE was increased to 9.5% from 8.47% retroactive to July 1, 2009 and its deemed equity percentage was increased to 40% from 35.01% effective January 1, 2010. In order to bring TGI's actual capital structure in line with the new 40% deemed equity level, TGI raised $125 million of common equity from its ultimate parent, FTS, in January 2010. We anticipate that these changes will cause CFO pre-WC + Interest / Interest (Cash Flow Interest Coverage) to be in the upper 2x range going forward versus the mid 2x range in recent years. Similarly, we anticipate CFO pre-WC / Debt will exceed 10% in the future versus its sub-10% level in the past few years.

The improvement in TGI's debt to capitalization as at March 31, 2010 also reflects the change in Canadian GAAP that took effect January 1, 2009 and requires regulated utilities to recognize deferred income tax liabilities. This had the effect of increasing capitalization and therefore reducing debt to capitalization since we include deferred taxes in capitalization.

Despite the increase in TGI's allowed ROE to 9.5% and deemed equity to 40%, these levels remain lower than those of U.S. gas LDCs which typically have allowed ROEs of 10% or more and deemed equity in the 50% range.

STRONG REGULATORY RING-FENCING SEPARATES TGI FROM PARENT, TERASEN INC.

We believe that TGI's ring-fencing is very good relative to that of its peers outside of British Columbia. TGI is subject to a set of regulatory ring-fencing conditions imposed by the BCUC. The ring-fencing conditions provide that, unless otherwise approved by the BCUC, TGI shall: maintain a ratio of common equity to total capital at least as high as the deemed equity capitalization utilized by the BCUC for ratemaking purposes (currently 40%); not pay dividends if they would cause TGI's common equity to total capital to fall below the BCUC's deemed equity percentage; not invest in or financially support non-regulated business; and not engage in affiliate transactions on anything other than an arm's length basis. We believe that the BCUC ring-fencing provisions effectively insulate TGI from the greater financial and business risks of its parents, TER and FTS. The regulatory ring-fencing provisions, combined with FTS' philosophy of requiring its utility operating subsidiaries to be operationally and financially independent of FTS and other subsidiaries, allow Moody's to evaluate TGI's credit profile on a stand-alone basis.

Liquidity Profile

TGI's liquidity is expected to be sufficient to meet its anticipated funding requirements. Availability under TGI's credit agreement at March 31, 2010 was $414 million which exceeds our $120 million estimate of the company's funding requirement for the subsequent four quarters.

TGI's $500 million syndicated committed revolving facility matures August 2013 and is available to support its $500 million commercial paper (CP) program and for general corporate purposes. The company is currently well below the debt to total capitalization ratio covenant (maximum 75%) in the credit agreement. Further, the syndicated credit agreement does not contain language such as Material Adverse Change (MAC) clauses or ratings triggers that would inhibit access to the unutilized portion of the facility in situations of financial stress.

TGI is expected to generate approximately $190 million of adjusted funds from operations (FFO) in the next 4 quarters. After dividends in the range of $85 million and capital expenditures and working capital changes of approximately $225 million, Moody's expects TGI to be free cash flow (FCF) negative by approximately $120 million. TGI has no material scheduled debt maturities during the four quarters ending June 30, 2011 resulting in a funding requirement of approximately $120 million.

Although utilization of TGI's credit facility was limited to roughly $86 million at March 31, 2010, during the peak gas storage season the financing of gas inventory can significantly reduce the unutilized portion of TGI's credit facility. For instance, at the end of the third quarter of 2008, availability under TGI's $500 million credit facility was only about $175 million. We recognize that TGI's reliance on short-term debt to finance gas inventories is supported by the BCUC and that the BCUC has approved the use of an interest rate deferral account to limit TGI's exposure to short-term interest rate volatility. However, we believe that TGI's financial flexibility can become somewhat constrained, particularly when material debt maturities fall within the peak storage season. However, this is not a concern in the near term as TGI's next significant debt maturity occurs in September 2015.

Rating Outlook

The stable outlook is predicated on TGI's low business risk as a regulated gas distribution utility, our expectation that TGI's regulatory environment will continue to be supportive and our belief that TGI's financial profile will improve modestly in 2010.

What Could Change the Rating - Up

We consider an upward revision in TGI's rating to be unlikely in the near term due to its relatively weak financial profile. However, the rating could be positively impacted if TGI could demonstrate a sustainable improvement in its credit metrics. All else being equal, at the A2 senior unsecured level, Moody's would expect TGI's Cash Flow Interest Coverage to exceed 4x and CFO pre-WC / Debt to be above 19%.

What Could Change the Rating - Down

Notwithstanding TGI's relatively low risk business profile, its financial profile is considered weak at the A3, senior unsecured rating level. Accordingly, a sustained weakening of TGI's Cash Flow Interest Coverage below 2.3x and CFO pre-WC / Debt below 8% combined with a less supportive and predictable regulatory framework would likely result in a downgrade of TGI's rating. This could occur if gas were to lose its competitive advantage over electricity in British Columbia due Provincial policies favouring non-carbon emitting energy sources or other factors.

Rating Factors

Terasen Gas Inc.

Regulated Electric and Gas Utilities Rating Methodology	Aaa	Aa	A	Baa	Ba	B
Factor 1: Regulatory Framework (25%)		X				
Factor 2: Ability to Recover Costs and Earn Returns (25%)			X			
Factor 3: Diversification (10%)						
a) Market Position (10%)			X			
b) Generation and Fuel Diversity (0%)			n/a			
Factor 4: Financial Strength, Liquidity & Financial Metrics (40%)						
a) Liquidity (10%)			X			
b) CFO pre-WC + Interest / Interest (7.5%)					2.5x	
c) CFO pre-WC / Debt (7.5%)					9.6%	
d) CFO pre-WC - Dividends / Debt (7.5%)					4.4%	
e) Debt / Capitalization or Debt / RAV (7.5%)						65.6%
Rating:						
a) Methodology Implied Senior Unsecured Rating			**A3**			
b) Actual Senior Unsecured Rating			**A3**			

DBRS

Insight beyond the rating.

Terasen Gas Inc.

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The Company
Terasen Gas Inc. (TGI or the Company) is the largest natural gas distributor in British Columbia, serving approximately 840,000 customers, representing 90% of the province's natural gas users. The Company is 100% owned by Terasen Inc. (rated BBB (high)), which is a wholly owned subsidiary of Fortis Inc. (rated BBB (high)). The ratings assigned to TGI are based predominantly on a stand-alone basis.

Rating

Debt	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
MTNs & Unsecured Debentures	A	Confirmed	Stable

Rating Update

DBRS has confirmed the Purchase Money Mortgages and the MTNs & Unsecured Debentures ratings of Terasen Gas Inc. (TGI or the Company) at "A" and its Commercial Paper rating at R-1 (low), all with Stable trends. The rating confirmations reflect TGI's low business risk natural gas distribution operations; a favourable regulatory environment, with strong ring-fencing provisions; a strong franchise area, with a large customer base; and a modestly improved financial profile.

In late 2009, TGI executed a negotiated settlement that established rates for 2010 and 2011. The settlement excluded the performance-based rate (PBR) mechanism, under which the Company had operated for the 2004 to 2009 period. The PBR had allowed TGI the opportunity to share earnings above the allowed return on equity (ROE) with customers on a 50/50 basis and had been beneficial to TGI as it had provided more than $11 million per year in earnings, on average, in 2008 and 2009. While the loss of this PBR income would have negatively affected TGI's financial results, this was largely offset by an improvement in regulatory allowed ROE (to 9.50% from the 8.43% that would otherwise have been in effect) and equity thickness (from 35.01% to 40%). The regulatory environment also continues to provide for a number of cost-recovery mechanisms that, when combined with the general rate-setting methodology, allow for a full recovery of all prudently incurred operating expenses and capital expenditures within a reasonable time frame.

The Company's credit metrics have historically remained consistent and are expected to continue to do so, with a modest lift from the recent regulatory changes. With the increases in approved ROE and equity thickness, partially offset by the loss of PBR, DBRS estimates an increase in the EBIT coverage metric of approximately 0.25 times and an increase of approximately 150 basis points in cash flow-to-debt over recent historicals. However, TGI's coverage metrics are expected to remain moderately lower than those of similarly rated gas distribution companies, even factoring in the improvements, a differential DBRS views as being offset by the Company's more stable credit metrics and business risk profile. (Continued on page 2.)

Rating Considerations

Strengths
(1) Low business risk and supportive regulatory framework
(2) Strong regulatory ring-fencing provisions
(3) Reasonable balance sheet and stable credit metrics
(4) Strong franchise area, with a large customer base

Challenges
(1) Long-term competitiveness of natural gas relative to alternative energy sources
(2) Volume exposure in the industrial and transportation segment
(3) ROE levels and loss of PBR incentive earnings

Financial Information

	For the 12-mos. ended Mar. 31/10	For the year ended December 31 2009	2008	2007	2006	2005
EBIT interest coverage (1)	2.1	1.9	1.9	1.9	2.0	1.9
% debt in capital structure (1)	59.9%	66.4%	66.4%	66.5%	64.7%	67.6%
Cash flow/total debt (times) (1)	11.7%	9.8%	8.8%	8.4%	9.7%	8.9%
Cash flow/capital expenditures (times)	1.3	1.2	1.2	1.3	1.5	1.5
Net income bef. extras (CAD millions)	102	87	78	70	68	70
Operating cash flow (CAD millions)	184	170	152	146	160	157

(1) Includes operating leases

Terasen Gas Inc.

Report Date:
July 22, 2010

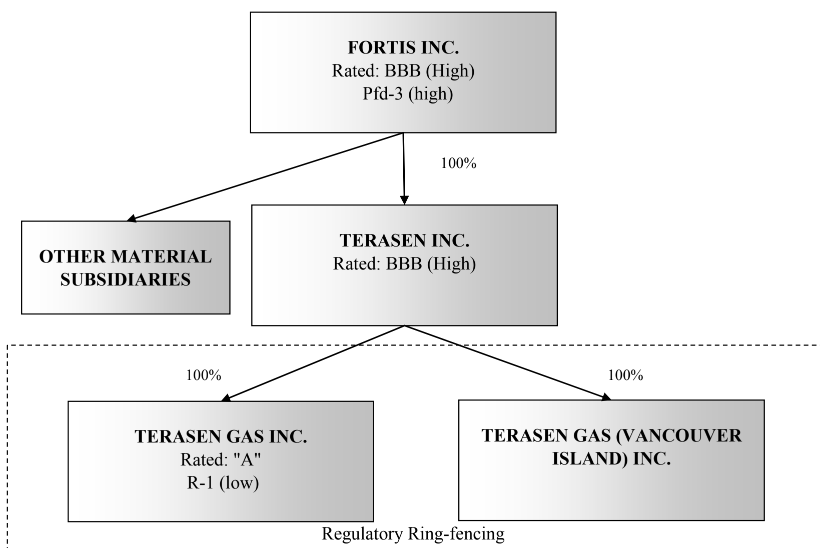
Rating Update (Continued from page 1.)

Minimal to modest free cash flow deficits are expected over the medium term, attributable to the replacement and refurbishment of existing infrastructure (which is expected to go into the rate base in a timely manner) and modest customer growth. Any deficits would be expected to be financed with a combination of the $500 million revolving bank facility ($414 million available at March 31, 2010) and long-term debt issuance. TGI's balance sheet is expected to remain stable over the medium term as the Company is expected to manage its dividends to maintain its capital structure within the recently revised regulatory-approved debt-to-equity ratio of 60%-to-40%.

DBRS expects the lower customer growth trend to continue, with fewer new housing starts and a shift in the housing mix to more multi-family dwellings. TGI is expected to focus on retaining customers through expanded energy conservation and efficiency programs.

The Company continues to maintain a price advantage relative to electricity, the primary competitor to natural gas. The current weaker gas pricing environment both improves TGI's competitiveness and reduces working capital and liquidity requirements. TGI's financial strength and credit profile over the longer term will depend to some extent on the continued competitiveness of natural gas relative to alternative energy sources (mainly electricity).

Simplified TGI Ownership and Rating Chart



Rating Considerations Details

Strengths

(1) TGI benefits from having all its operations in a low-risk, stable regulated environment within a supportive regulatory framework. TGI operates under a full cost-of-service recovery regime, with deferral accounts existing to stabilize earnings and to adjust for the recovery/refund of shortfalls/overages of natural gas costs from/to customers. TGI has no exposure to commodity costs (subject to a recovery lag) as natural gas costs are fully passed on to customers, with quarterly adjustments.

(2) Regulatory ring-fencing conditions imposed on TGI in the 2007 British Columbia Utilities Commission (BCUC) order approving acquisition of Terasen Inc. by Fortis Inc. are viewed as positive for TGI's credit profile, offering protection from significant changes in its capital structure.

(3) TGI has historically maintained a stable balance sheet and credit metrics, with some modest improvement attributable to recent regulatory changes. While the EBIT coverage and cash flow-to-debt ratios have improved and are expected to remain at more modestly favourable levels, they remain on the lower end for an "A" rating compared with its gas distribution peers. However, DBRS remains comfortable with TGI's rating given the inherent stability its credit metrics have shown over time.

(4) TGI serves a large customer base of approximately 840,000, located in a stable franchise area that includes the city of Vancouver. The customer mix is favourable, with residential and commercial customers accounting for 90% of distribution revenues. There is no volume risk (but recovery lag exists) associated with this customer segment.

Challenges
(1) TGI's earnings and financial profile over the longer term will largely depend on the competitive position of natural gas relative to alternative energy sources (mainly electricity) in British Columbia. Despite the significant increases in natural gas prices through 2008, natural gas continued to maintain a competitive advantage over electricity in terms of pricing. While gas prices have since retreated, it is expected that under reasonable gas price assumptions, TGI will remain competitive relative to electricity, with electricity prices expected to rise gradually in the medium term, according to British Columbia Hydro & Power Authority (BC Hydro).

(2) The Company is exposed to variances from forecasts when it comes to its industrial fixed-price contracts and transportation-services segments, which represent approximately 45% of throughput volumes (5% of revenues). However, this exposure is mitigated by the fact that their usage is less likely to be significantly affected by weather and is therefore more predictable. TGI conducts an annual survey of its industrial customer segment to minimize forecast variances in throughput volumes. Further mitigating this risk is the fixed demand charges derived from this segment.

(3) Although the BCUC terminated the automatic ROE adjustment formula and set the approved level at 9.50% (effective July 1, 2009), it had been below 9% for the prior three years, negatively affecting earnings and cash flows. With use of the adjustment formula having been terminated, there is uncertainty as to how ROE levels will be determined in the medium and longer term; the BCUC has directed TGI to investigate alternative mechanisms. Additionally, under the prior PBR, TGI shared earnings above or below the allowed ROE on a 50/50 basis with customers. The loss of this is expected to largely offset the credit metric upside of the ROE increase as TGI's incentive earnings averaged more than $11 million per year in 2008 and 2009.

Regulation

Regulatory Overview
TGI is regulated by the BCUC on a test-year forecast basis under a rate-of-return/cost-of-service regime. TGI applies to the BCUC for approval of rates to recover its forecast cost-of-service. TGI's cost of service includes the cost of purchased gas and the cost of gas transportation and distribution through the pipeline system, including operating, maintenance and administrative expenses (OM&A); depreciation of facilities; interest; income and other taxes; and ROE.

TGI purchases gas for resale, without markup, to residential and commercial customers; transportation customers and some large commercial and industrial customers arrange for their own gas supply and contract with TGI for the transportation of that gas. TGI's rates are based on estimates of several items, such as natural gas sales volumes, cost of natural gas and interest rates. In order to manage the risks associated with some of these estimates, a number of regulatory deferral accounts are in place.

- **Commodity Cost Reconciliation Account and Midstream Cost Reconciliation Account:** The differences between actual and forecast gas costs are recorded in these deferral accounts to be recovered or refunded in future rates. This exposes TGI to a recovery lag (the balances are anticipated to be fully recovered or refunded within the next fiscal year), but price adjustments are made on a quarterly basis to better reflect prevailing gas commodity prices. This mitigates the impact of recovery lag.

- **Revenue Stabilization Adjustment Account (RSAM):** The RSAM seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use throughout the year. The RSAM account is anticipated to be recovered in rates over three years (for comparison, in Ontario, gas distribution companies are exposed to volume risk, which can be significant due to changes in the weather). Variances in usage by large-volume industrial transportation and sales customers, which account for 45% of total throughput, are not covered by this deferral account. However, their usage is more predictable and less likely to be significantly affected by weather.
- TGI also has short- and long-term interest rate deferral accounts to absorb interest rate fluctuations.

Under the PBR, which was in effect from 2004 to 2009, operating and maintenance costs and base-capital expenditures were subject to an incentive formula that reflected increasing costs as a result of customer growth and inflation less a productivity factor. The PBR provided for a 50/50 sharing mechanism of earnings above or below the allowed ROE. However, in 2009, a negotiated settlement was reached that established TGI's rates for 2010 and 2011; PBR ended in 2009 and is not part of the negotiated settlement, which allows for the incorporation into rates of changes to the BCUC-determined levels of ROE and common equity.

Allowed ROE had been set annually according to a formula based on a forecast of 30-year Canada Bonds plus a 3.90% risk premium when the forecast yield is 5.25%. The risk premium was adjusted annually by 75% of the difference between 5.25% and the forecast yield. The common equity component of the capital structure was set at 35.01%. However, in 2009, TGI filed a BCUC application requesting an increase in the common equity component and a higher return on equity. In its decision, the BCUC determined that the ROE adjustment mechanism would no longer apply and that an ROE of 9.50% would be in effect from July 1, 2009, until amended; the BCUC directed TGI to complete a study of alternative mechanisms and report back by the end of 2010.

TGI's common equity component was also increased from 35.01% to 40%, effective January 1, 2010; TGI received a $125 million equity injection early in January 2010 to bring its capital structure into alignment with this revision. Forecast capital expenditures are also approved by the BCUC.

Regulatory Ring-Fencing

A summary of the regulatory ring-fencing conditions in the April 30, 2007, BCUC order imposed on TGI approving the Fortis Inc. acquisition of Terasen Inc. is as follows:

- TGI must maintain the equity in the capital structure at least at the deemed equity level approved by the BCUC (now 40%).
- TGI must obtain approval from the BCUC before paying dividends to its parent if the paying of dividends can be reasonably expected to increase leverage above the approved level.
- The Company will not be allowed to lend to, guarantee or financially support any affiliates of Terasen Inc. or its non-regulated businesses.
- TGI will not be allowed to enter a tax-sharing agreement with any of its affiliates unless the agreement has been approved by the BCUC.
- TGI must maintain the continued independence of directors.

Earnings and Outlook

Consolidated Earnings

(CAD millions)	For the 12-mos. ended Mar. 31/10	For the year ended December 31 2009	2008	2007	2006	2005
Net revenues	550	526	513	507	517	505
EBITDA	319	297	292	293	301	302
EBIT	233	214	214	215	217	222
Gross interest expense	107	109	111	108	106	112
Pre-tax income	126	106	103	108	112	111
Income taxes	25	19	25	38	44	42
Net income (before extras)	102	87	78	70	68	70
Net income	102	87	92	78	68	65
Return on avg. common equity (bef. extras.)	10.4%	9.9%	8.9%	7.9%	7.8%	8.4%
EBIT margin (net of gas costs)	42.3%	40.7%	41.7%	42.3%	42.0%	44.1%
Rate Base*	2,542	2,547	2,510	2,484	2,516	2,406
Approved common equity	40.00%	35.01%	35.01%	35.01%	35.01%	33.00%
Allowed ROE**	9.50%	8.47%	8.62%	8.37%	8.80%	9.03%

* $2,542 million for 2010. ** 8.47% for first six months of 2009, 9.50% for second six months

Summary

TGI has historically demonstrated very stable levels of EBITDA and EBIT, reflective of modest net additions to its customer base, increases in its rate base and a stable approved equity component, all largely offset by declining allowed ROE levels. Earnings volatility is further reduced due to the customer breakdown, with residential and commercial customers providing the majority of its margin and industrial customers normally under contract. Much of the recent modest improvement in earnings is attributable to the recent BCUC decision to increase both the common equity component and the approved ROE. Growth in multi-family housing continues to have an impact on net additions as natural gas is less prevalent in this type of dwelling.

The gas distribution segment (residential and commercial customers) has historically accounted for more than 50% of total throughput volumes and 90% of total revenues. Throughputs for this segment exhibit stability, and any volume risk is mitigated as shortfalls/overages in volume revenues are deferred and recovered/refunded through future rates.

The transportation segment and industrial customers under fixed-price contracts have historically accounted for approximately 50% of total throughput volumes and less than 10% of total revenues. Although transportation and industrial customer segments are exposed to volume risk, it is mitigated by the fact that their usage is less likely to be significantly affected by weather and is therefore more predictable. Further mitigating this risk is the fixed demand charges derived from these segments. Interest expense has been relatively stable over the past five years due to fairly consistent levels of total debt.

Outlook

DBRS expects earnings to continue at their modestly higher levels due to the impact of the higher equity component and approved ROE, modestly offset by the negative impact of the loss of incentive earnings upon expiry of the PBR mechanism. Over the medium term, as a mature gas distribution utility, TGI is expected to have relatively stable earnings, with some variability due to allowed ROE, population growth, new housing starts and customer conversions.

Over the longer term, earnings will largely depend on the competitiveness of natural gas relative to electricity in British Columbia. While TGI has maintained a competitive advantage in terms of pricing compared with electricity, its competitive position would weaken should gas prices increase significantly for a prolonged period of time, potentially having a negative impact on TGI's financial and credit profile. The competitiveness of natural gas will also be affected by the provincial consumption tax on carbon-based fuels.

Terasen Gas Inc.

Report Date:
July 22, 2010

Financial Profile

(CAD millions)	For the 12-mos. ended Mar. 31/10	For year ended Dec. 31 2009	2008	2007	2006	2005
Net income before extraordinary items	102	87	78	70	68	70
Depreciaton & amortization	86	83	78	79	84	79
Other non-cash adjustments	(4)	0	(5)	(3)	8	8
Cash Flow From Operations	184	170	152	146	160	157
Capital expenditures	(140)	(139)	(122)	(108)	(109)	(103)
Common dividends	(75)	(67)	(100)	(111)	(40)	(60)
Free Cash Flow Before W/C Changes	(30)	(36)	(70)	(73)	12	(7)
Working capital changes	(10)	16	33	(28)	83	(45)
Net Free Cash Flow	(40)	(20)	(37)	(101)	95	(51)
Acquisitions/divestitures	0	0	14	0	0	(42)
Other adjustment/comprehensive	(13)	7	36	11	(7)	(2)
Cash flow before financing	(53)	(13)	13	(90)	88	(95)
Net change in debt financing	(86)	6	(5)	89	(98)	109
Net change in pref. share financing	0	0	0	0	0	0
Net change in equity financing	125	0	0	0	0	0
Net Change in Cash	(13)	(7)	8	(1)	(9)	14
Total adjusted debt (CAD million) (1)	1,573	1,737	1,730	1,744	1,655	1,763
Cash flow/total debt (times) (1)	11.7%	9.8%	8.8%	8.4%	9.7%	8.9%
% debt in the capital structure (1)	60%	66%	66%	67%	65%	68%
EBIT interest coverage (times)	2.1	1.9	1.9	1.9	2.0	1.9
Dividend payout ratio (%)	74%	77%	128%	158%	58%	86%

(1) Includes operating leases

Summary

TGI has maintained stable cash flow from operations, which historically has been largely adequate to fund both capital expenditure and dividend payments. The recent uptick is attributable to the recent regulatory changes to ROE and equity thickness. The level of dividends is expected to continue to maintain TGI's capital structure in line with BCUC-approved levels. TGI has received a $125 million equity injection to bring its capital structure in line with the BCUC's decision to increase the common equity component to 40%. Proceeds were largely used to reduce debt.

As part of the ring-fencing condition, TGI is prohibited from paying dividends unless it has in place at least as much equity as required by the BCUC for rate-making purposes (now 40%). Leverage has thus improved to 60%, with a commensurate modest improvement in coverage metrics expected. The stability of TGI's coverage metrics continues to be a key factor in its ratings.

Outlook

Minimal to modest free cash flow deficits are expected over the medium term, attributable to the replacement and refurbishment of existing infrastructure and modest customer growth. Any deficits are expected to be financed with a combination of TGI's $500 million revolving bank facility ($414 million available at March 31, 2010) and long-term debt issuance. DBRS expects the capital expenditure to be approximately $150 million (before customer contributions) annually over the medium term, with maintenance capital expenditure expected to account for approximately 70% to 80% of the total.

TGI's financial profile should remain relatively stable over the medium term as the Company is expected to manage its dividends to maintain its capital structure within the recently approved 60%-to-40% debt-to-equity ratio. With the recent regulatory changes, DBRS estimates the following improvements: cash flow-to-total debt to move from its historic 8% to 10% range to approximately 10% to 12% and EBIT-to-interest to remain greater than 2.0 times. Longer term, under reasonable gas and electricity price assumptions, it is expected that TGI will remain competitive relative to alternative energy sources.

Long-Term Debt Maturities and Liquidity

As at Mar. 31, 2010 (CAD millions)	2010	2011	2012	2013	2014	Thereafter	Total
Long-Term Debt	2	2	2	2	2	1,447	1,456

TGI has a five-year, $500 million unsecured committed revolving credit facility with a syndicate of banks that matures in August 2013; $414 million was unutilized at March 31, 2010. The credit facility is primarily used to support TGI's $500 million commercial paper (CP) program and working capital requirements, which vary to a large extent with seasonal gas inventory levels. Gas inventory levels and working capital requirements typically peak in the fall and winter seasons, with reductions in the spring and summer. The debt-repayment schedule is negligible in the near term.

TGI's bond indenture contains an EBIT-to-interest coverage test in order to issue additional indebtedness. EBIT for 12 consecutive months out of the previous 23 months must be at least 2.0 times its annual pro forma interest requirements for debt that has a maturity term longer than 18 months.

Terasen Gas Inc.

Report Date:
July 22, 2010

Terasen Gas Inc.

Balance Sheet
(CAD millions)

	As at December 31					As at December 31	
Assets	Mar. 31/10	2009	2008	**Liabilities & Equity**	Mar. 31/10	2009	2008
Cash	4	6	13	Short-term debt	40	204	239
Accounts receivable	268	277	346	L.t.d. due in one year	2	2	62
Inventories	108	149	192	A/P	360	337	366
Prepaid expenses	2	23	3	Tax payables	41	42	66
Rate stabilization accts	146	69	54	Rate stabilization acct.	2	12	24
Current Assets	528	524	608	**Current Liabilities**	446	597	755
Net fixed assets	2,429	2,489	2,432	Long-term debt	1,441	1,440	1,340
Rate stabilization accts	0	0	0	Deferred credits	163	173	138
Deferred charges	0	0	0	Deferred taxes	275	276	1
Long-term rec. + investments	420	355	69	Shareholders' equity	1,051	881	875
Total	3,377	3,368	3,109	**Total**	3,377	3,368	3,109

Ratio Analysis	For the 12-mos.	For the year ended December 31				
Liquidity Ratios	ended Mar. 31/10	2009	2008	2007	2006	2005
Current ratio	1.18	0.88	0.80	0.66	0.65	0.74
Accumulated depreciation/gross fixed assets	na	24.1%	23.8%	23.4%	23.5%	21.9%
Cash flow/total debt (1)	11.7%	9.8%	8.8%	8.4%	9.7%	8.9%
Cash flow/capital expenditure	1.32	1.22	1.24	1.35	1.47	1.52
Cash flow-dividends/capital expenditures	0.78	0.74	0.43	0.33	1.11	0.94
% debt in capital structure (1)	59.9%	66.4%	66.4%	66.5%	64.7%	67.6%
Approved common equity	40.00%	35.01%	35.01%	35.01%	35.01%	33.00%
Common dividend payout (before extras.)	73.8%	77.4%	127.7%	158.0%	58.5%	86.3%
Coverage Ratios						
EBIT interest coverage (1)	2.1	1.9	1.9	1.9	2.0	1.9
EBITDA interest coverage (1)	2.9	2.6	2.6	2.6	2.8	2.7
Fixed-charges coverage (1)	2.1	1.9	1.8	1.9	2.0	1.9
Debt/EBITDA	4.9	5.9	5.9	6.0	5.5	5.8
Earnings Quality						
EBIT margin, excluding cost of natural gas	42.3%	40.7%	41.7%	42.3%	42.0%	44.1%
Net margin (excluding preferred dividends)	18.5%	16.5%	15.3%	13.8%	13.2%	13.8%
Return on avg. common equity (bef. extras.)	10.41%	9.87%	8.93%	7.89%	7.8%	8.4%
Allowed ROE *	9.50%	8.47%	8.62%	8.37%	8.80%	9.03%
Operating Statistics						
Customer growth	n/a	0.6%	1.1%	1.2%	1.3%	1.6%
Operating costs/avg. customer (CAD)	321	316	306	303	318	304
Rate base (CAD millions)	2,542	2,547	2,510	2,484	2,516	2,406
Rate base growth	-0.2%	1.5%	1.0%	-1.3%	4.6%	4.2%

(1) Includes operating leases

* 8.47% for first six months of 2009, 9.50% for second six months

Operating Statistics

	For year ended December 31				
Throughput Volumes	2009	2008	2007	2006	2005
Residential	72.7	78.5	74.9	68.7	69.4
Commercial	42.4	44.1	42.3	38.4	39.1
Small industrial	3.0	3.1	3.4	3.8	4.2
Large industrial	0.2	0.1	0.2	0.2	0.3
Total Natural Gas Sales Volumes	118.3	125.8	120.8	111.1	113.0
Transportation service	54.0	57.3	62.3	62.3	63.9
Throughput under fixed-price contracts	36.0	39.6	36.8	36.8	36.4
Total Throughputs (PJs)	208.3	222.7	219.9	210.2	213.3
Customers					
Residential	755,660	750,838	742,882	733,598	723,898
Commercial	81,274	81,012	79,717	79,113	78,497
Small industrial	251	284	297	325	396
Large industrial	31	33	40	40	45
Transportation	2,078	2,059	2,041	1,956	1,907
Total (thousands)	839,294	834,226	824,977	815,032	804,743

Terasen Gas Inc.

Report Date:
July 22, 2010

Ratings

Debt Rated	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
MTNs & Unsecured Debentures	A	Confirmed	Stable

Rating History

Debt Rated	Current	2009	2008	2007	2006	2005
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Purchase Money Mortgages	A	A	A	A	A	A
MTNs & Unsecured Debentures	A	A	A	A	A	A

Related Research

- Recent Regulatory Developments for Canadian Pipeline and Utility Companies, February 10, 2010.

Note:
All figures are in Canadian dollars unless otherwise noted.

Moody's Investors Service

Credit Opinion: Terasen Gas (Vancouver Island) Inc.

Global Credit Research - 12 Mar 2010

Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Parent: Terasen Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa2
Subordinate -Dom Curr	Baa3
Parent: Terasen Gas Inc.	
Outlook	Stable
Senior Secured -Dom Curr	A1
Senior Unsecured -Dom Curr	A3

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Key Indicators

[1]**Terasen Gas (Vancouver Island) Inc.**

	[2]**LTM**	**2008**	**2007**	**2006**	**2005**
(CFO Pre-W/C + Interest) / Interest Expense	**4.2x**	**3.9x**	**3.8x**	**3.5x**	**3.6x**
(CFO Pre-W/C) / Debt	**14.5%**	**15.2%**	**13.5%**	**12.4%**	**16.5%**
(CFO Pre-W/C - Dividends) / Debt	**9.8%**	**11.6%**	**8.6%**	**10.6%**	**11.6%**
Debt / Book Capitalization	**61.2%**	**66.4%**	**67.2%**	**65.6%**	**64.2%**

[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, 2009

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Regulated gas transmission and distribution utility with no unregulated operations

High cost of service and small size balanced by strong political and regulatory support

Business risk associated with the expiry of Government royalty payments at the end of 2011

Elevated capex and leverage during construction of Mt. Hayes LNG storage facility.

Strong regulatory ring-fencing mechanisms.

Corporate Profile

Terasen Gas (Vancouver Island) Inc. (TGVI) is a natural gas transmission and distribution utility serving approximately 98,000 customers on Vancouver Island and the Sunshine Coast. TGVI, which has no unregulated operations, is regulated on a cost of service basis by the British Columbia Utilities Commission (BCUC). TGVI is one of the smallest gas utilities rated by Moody's with a 2009 mid-year rate base of approximately $540 million.

TGVI is a wholly-owned subsidiary of Terasen Inc. (TER), a holding company which also owns 100% of Terasen Gas Inc. (TGI) and Terasen Gas Whistler Inc. (TGW). TER has been a wholly-owned subsidiary of Fortis Inc. (FTS) since May 17, 2007.

SUMMARY RATING RATIONALE

TGVI's A3 senior unsecured rating and stable outlook reflect TGVI's status as a regulated gas local distribution company (LDC). However, TGVI's high cost of service and small size cause its business risk to be higher than most gas LDCs. In addition, TGVI's credit metrics are weaker than those of international peers. However, we view TGVI's high cost of service, small size and weak metrics as being balanced by the long history of supportive regulatory and political decisions.

The rating also reflects our expectation that various factors will cause TGVI's rates to rise over the next few years. Rising rates would negatively impact the competitiveness of natural gas relative to other forms of energy which could result in reduced demand for gas and even more upward pressure on rates. Nothwithstanding, we anticipate that gas will remain attractive relative to electricity, which is the primary alternative in TGVI's service territory, due to our expectation that electricity rates will increase significantly each year for the foreseeable future. However, if gas were to lose its cost advantage in TGVI's service territory, we believe that it is likely that TGVI and TGI would be merged and that rates would be harmonized across both service territories. We believe that rate harmonization would lower rates in TGVI's service territory and restore gas' cost advantage.

TGVI's A3 rating is consistent with the A3 rating implied by Moody's Regulated Electric and Gas Utilities Rating Methodology.

DETAILED RATING CONSIDERATIONS

HIGH COST OF SERVICE BALANCED BY STRONG POLITICAL AND REGULATORY SUPPORT

TGVI's system has a high capital cost per customer and has relied heavily on regulatory and political support to ensure that its rates have been competitive with the costs of other forms of energy. TGVI's high capital costs per customer reflect the significant investment in transmission infrastructure required to reach the relatively small customer base on Vancouver Island. Also, TGVI's market penetration is generally lower than that of TGI.

To ensure that natural gas was roughly cost competitive with fuel oil and electricity, the Province, the BCUC and TGVI agreed to a number of mechanisms. Firstly, TGVI's rates have been capped at levels similar to those of alternative forms of energy. Secondly, the Province provides financial support under the Vancouver Island Natural Gas Pipeline Agreement (VINGPA) in the form of royalty revenue payments to TGVI which subsidize consumers' gas costs. Thirdly, both the Province and the Federal Government have provided TGVI with non-interest bearing loans.

Prior to 2003, TGVI's rates were insufficient to cover TGVI's costs of service and the shortfall was deferred in the Revenue Deficiency Deferral Account (RDDA). In 2003 TGVI reached a point where, with the benefit of the Provincial royalty revenues, it was able to recover its costs of service and also begin to recover the accumulated regulatory assets (principally the RDDA) while charging rates that were roughly competitive with costs of alternative sources of energy on Vancouver Island. By late 2009, TGVI had fully recovered the RDDA and begun to accumulate revenue surpluses.

In addition to support provided by the Provincial Government, TGVI has benefited from British Columbia's economic performance, which has until recently been relatively strong. Moody's considers Canada to have supportive regulatory and business environments relative to other jurisdictions globally. Furthermore, the regulatory environment in the Province of British Columbia is considered one of the more supportive in Canada. This view reflects the fact that regulatory proceedings tend to be less adversarial and decisions tend to be timely and balanced.

RATE PRESSURES COULD ADVERSELY IMPACT DEMAND

There are a number of factors which we believe will cause TGVI's rates to rise over the next few years. Depending on the extent of the increase in TGVI's rates and the degree to which the costs of alternative sources of energy increase, it is possible that the competitiveness of TGVI's rates and therefore the demand for gas within TGVI's service territory could be adversely impacted. In the extreme, the loss of a cost advantage could lead to spiraling rate increases and demand destruction. While we do not believe this to be a likely scenario, if it were to occur, we expect that TGVI and TGI would be merged and their rates would be harmonized. Rate harmonization would be expected to eliminate the cost disadvantage of gas on Vancouver Island as the higher costs of TGVI's system would be spread across TGI's larger base of approximately 839,000 customers (more than eight times TGVI's customer base).

While TGVI has been able to recover its costs of service and the accumulated RDDA balances since 2003, it has only been able to do so with the benefit of the Provincial royalty payments. Under the terms of the VINGPA, these royalty payments terminate at the end of 2011. Consequently, TGVI's rates will need to increase in 2012 to offset the loss of the Provincial royalty revenues. Initially, the rate impact of the loss of royalty revenues is expected to be partially mitigated by the amortization of accumulated revenue surpluses that are anticipated to occur during 2010 and 2011. Pursuant to the BCUC-approved negotiated settlement for TGVI's 2010/2011 rates, the company expects to recover more than its cost of service during those two years and will record any surpluses in a new deferral account, the Rate Stabilization Deferral Account or RSDA. Following the termination of the Provincial royalty revenues, the RSDA balance will be amortized and therefore reduce the need to increase rates to offset the lost royalty revenues. However, when the RSDA has been fully amortized, TGVI's rates will need to increase.

As of December 2009, the balance of TGVI's Provincial and Federal non-interest bearing loans was approximately $53 million. TGVI anticipates that this amount will be repaid between 2012 and 2016. As these loans are repaid, TGVI's rate base will increase by a like amount since these loans are treated as an offset to rate base for regulatory purposes.

In 2011, TGVI's Mt. Hayes liquefied natural gas (LNG) storage facility (described below) is expected to enter service and increase rate base by roughly $215 million. While the majority of the costs associated with Mt. Hayes will be covered by contractual payments from TGI, TGVI's customers will have to absorb roughly one third of the costs of Mt. Hayes through higher rates.

While we see upward pressure on TGVI's rates, we also expect the costs of alternative forms of energy to rise which could help preserve gas' cost advantage. For example, we note that BC Hydro applied for an effective 9.26% increase in its rates effective April 1, 2010. Moody's anticipates that the price of electricity in British Columbia will grow at well in excess of the rate of inflation for an extended period of time which could provide TGVI with some breathing room.

However, we believe that the Province of British Columbia would be supportive if rate harmonization were ultimately required to preserve gas competitiveness in TGVI's service territory. The Province has long provided financial and regulatory support to TGVI in order to promote its policy goal of ensuring availability of gas on Vancouver Island. While Provincial support of amalgamation/rate harmonization is not assured, it is Moody's view that it is unlikely that the Province would simply stand by and allow the Vancouver Island gas distribution infrastructure to falter and fail given the Province's well established track-record of supporting the development of TGVI's franchise. Moody's also notes that there is a precedent for such a transaction within the Terasen group of companies: in November 2006, Terasen Gas (Squamish) Inc. was amalgamated with TGI and the rates of the two entities were harmonized. While TGVI is considerably larger than Terasen Gas (Squamish), we believe the Squamish transaction is a positive precedent in the event that at some point in the future, the long-term competitiveness of TGVI's rates comes into question.

VOLATILE CREDIT METRICS IN NEAR TERM

In December 2009, the BCUC set its benchmark ROE for 2010 at 9.5% and decided to abandon its automatic ROE adjustment mechanism. In that same decision, the BCUC reduced TGVI's ROE premium to 50 basis points (BP) from 70 BP. On balance, the decision is slightly positive for TGVI in that TGVI's 2010 ROE of 10% is higher than it would have been had the BCUC retained its automatic adjustment mechanism. Notwithstanding, we expect TGVI's credit metrics to be volatile for the next few years. During 2010 and 2011, TGVI's cash flows will benefit from the collection of revenues in excess of its cost of service. Commencing 2012 we expect cash flows to decline due to the cessation of the Provincial royalty revenues which will not be immediately offset by rate increases due to the non-cash amortization of revenue surpluses accumulated in 2010 and 2011. However, we expect there will be a new cash flow stream related to the Mt. Hayes project whose first full year of operation is expected to be 2012. The completion of Mt. Hayes should also cause TGVI's (Moody's-adjusted) interest costs to be lower at the margin as the short-term debt used to construct the facility will be replaced with a mix of long-term debt and equity. Currently, we do not expect TGVI's cash flows and metrics to stabilize until approximately 2014.

ELEVATED CAPEX DUE TO CONSTRUCTION OF MT. HAYES LNG STORAGE FACILITY

TGVI is currently constructing the 1.5 bcf Mt. Hayes LNG storage facility. Based on an estimated cost of approximately

$215 million, the value of the project would exceed 40% of TGVI's 2009 rate base of roughly $540 million. As of early 2010, the project was on schedule and within budget.

TGVI plans to finance Mt. Hayes primarily with short-term debt until the project is completed and is placed in rate base (currently expected to occur in 2011). On completion we expect that TGVI's ultimate parent, FTS, will provide an equity injection to bring TGVI's capital structure into line with the BCUC's deemed capital structure. Accordingly, during the construction period, TGVI's debt to capital will be higher than it otherwise would be and its cash flow metrics will be lower than they otherwise would be.

While the Mt. Hayes project is large relative to TGVI's rate base, Moody's does not expect that its construction will pose a significant credit challenge for TGVI given the progress to date and the experience of the TGI/TGVI management team. Once in service, Mt. Hayes will contribute to higher rates although this impact is mitigated by a contract under which TGI bears roughly two thirds of costs of the facility.

STRONG REGULATORY RING-FENCING SEPARATES TGVI FROM PARENT, TERASEN INC.

Moody's believes that TGVI's ring-fencing is very good relative to that of its peers outside of British Columbia. TGVI is subject to a set of regulatory ring-fencing conditions imposed by the BCUC. The ring-fencing conditions provide that, unless otherwise approved by the BCUC, TGVI shall: maintain a ratio of common equity to total capital at least as high as the deemed equity capitalization utilized by the BCUC for ratemaking purposes (currently 40%); not pay dividends if they would cause TGVI's common equity to total capital to fall below the BCUC's deemed equity percentage; not invest in or financially support non-regulated business; and not engage in affiliate transactions on anything other than an arm's length basis. Moody's believes that the BCUC ring-fencing provisions effectively insulate TGVI from the greater financial and business risks of its parents, TER and FTS. The regulatory ring-fencing provisions, combined with FTS' philosophy of requiring its utility operating subsidiaries to be operationally and financially independent of FTS and other subsidiaries, allow Moody's to evaluate TGVI's credit profile on a stand-alone basis.

Liquidity Profile

Moody's views TGVI's liquidity resources as weak pending a renegotiation or extension of its primary credit facility. TGVI maintains a $350 million syndicated committed revolving credit agreement which matures on January 13, 2011. The credit agreement contains two maintenance covenants (debt to equity not greater than 70% and EBIT to interest expense not less than 2:1). As at September 2009, TGVI's leverage and coverage were 64.4% and 4.1x, respectively, leaving reasonable headroom under the covenants. TGVI's credit agreement does not contain language such as a Material Adverse Change (MAC) clause or ratings triggers that would inhibit access to the unutilized portion of the facility in situations of financial stress. At December 2009, approximately $194 million was available under the facility.

TGVI is expected to generate approximately $66 million of funds from operations (FFO) in 2010. After and working capital changes and capital expenditures totaling approximately $90 million and dividends in the range of $20 million, Moody's expects TGVI to be free cash flow negative by approximately $45 million in 2010. While the availability under TGVI's credit agreement is expected to be sufficient to fund its anticipated 2010 funding requirement, we consider the fact that the facility matures within the 12 month horizon of our liquidity stress scenario to be a weakness. We anticipate that TGVI will address this issue during the second quarter of 2010.

Rating Outlook

The stable outlook reflects our expectation that TGVI will be able to recover its costs of service while charging rates competitive with the costs of alternative forms of energy following the cessation of provincial royalty revenues in 2011.

What Could Change the Rating - Up

We consider it unlikely that TGVI's rating would be upgraded in the foreseeable future. However, an upgrade to A2 would require a combination of materially stronger metrics and improved liquidity. We would expect to see CFO pre-WC Interest Coverage in excess of 4.5x; CFO pre-WC/Debt approaching 20% and Retained Cash Flow (RCF)/Debt in the low teens on a sustainable basis. This is unlikely to occur in the absence of significant increases in deemed equity and allowed ROE.

What Could Change the Rating - Down

A downgrade to Baa1 would likely be caused by changes in political and/or regulatory policy that disadvantage gas relative to electricity and cause a weakening of TGVI's financial metrics. For instance, CFO pre-WC Interest Coverage in the low 3x range; CFO pre-WC/Debt in the low teens and RCF/Debt in the mid single digit range on a sustained basis.

Rating Factors

Terasen Gas (Vancouver Island) Inc.

Regulated Electric and Gas Utilities Rating Methodology	Aaa	Aa	A	Baa	Ba	B
Factor 1: Regulatory Framework (25%)			X			
Factor 2: Ability to Recover Costs and Earn Returns (25%)		X				
Factor 3: Diversification (10%)						
a) Market Position (10%)				X		
b) Generation and Fuel Diversity (0%)				n/a		
Factor 4: Financial Strength, Liquidity & Financial Metrics (40%)						
a) Liquidity (10%)			X			
b) CFO pre-WC + Interest / Interest (7.5%)				X		
c) CFO pre-WC / Debt (7.5%)				X		
d) CFO pre-WC - Dividends / Debt (7.5%)				X		
e) Debt / Capitalization or Debt / RAV (7.5%)						X
Rating:						
a) Methodology Implied Senior Unsecured Rating			**A3**			
b) Actual Senior Unsecured Rating			**A3**			

Moody's Investors Service

Rating Report

Report Date:
September 19, 2011

Previous Report
July 22, 2010

Insight beyond the rating.

FortisBC Energy Inc.

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The Company

FortisBC Energy Inc. (FEI or the Company) is the largest natural gas distributor in British Columbia (B.C. or the Province, rated AA (high)), serving approximately 846,000 customers and representing approximately 90% of the province's natural gas users. The Company is 100% owned by FortisBC Holdings Inc. (FHI, rated BBB (high)), which is a wholly-owned subsidiary of Fortis Inc. (FTS, rated A (low)).

Commercial Paper Limit

$500 million

Recent Actions

September 16, 2011
Confirmed

March 1, 2011
Name Change

Rating

Debt	Rating	Rating Action	Trend
MTNs & Unsecured Debentures	A	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Rationale

On September 16, 2011, DBRS confirmed the MTNs & Unsecured Debentures and Purchase Money Mortgages ratings of FortisBC Energy Inc. (FEI or the Company, formerly known as Terasen Gas Inc.) at "A", and its Commercial Paper rating at R-1 (low). The trends are Stable. The ratings reflect FEI's low business risk operations within a stable regulatory environment and franchise area, strong ring-fencing provisions, as well as its relatively sound financial profile and credit metrics compared with peers. The ratings also reflect the Company's relatively low allowed ROE, loss of performance-based rate (PBR) incentive earnings, ongoing exposure to volume risk from its industrial and transportation segments and the continued challenge of natural gas' long-term competitiveness vis-à-vis alternative energy sources.

FEI, FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) are expected to file an application in the Fall of 2011 to amalgamate the three utility subsidiaries under FortisBC Holdings Inc. (FHI, rated BBB (high)). The amalgamation will require the British Columbia Utilities Commission's (BCUC) approval and the Government of British Columbia's consent to proceed. At this time, DBRS anticipates that the potential amalgamation and associated rate harmonization will likely be credit neutral to FEI provided that there are no material changes that will negatively affect its deemed capital structure, allowed ROE or fundamental low-risk business model. DBRS notes that FEI's current contribution to FHI's overall earnings is approximately 75% and anticipates that the bulk of the amalgamated entity's earnings will continue to be derived from FEI. Should the potential amalgamation proceed, DBRS may re-examine any impacts to FEI and the consolidated utility's credit profile as a result of changes to the capital structure or ROE. (Continued on page 2.)

Rating Considerations

Strengths

(1) Low business risk operations within a stable regulatory environment
(2) Strong regulatory ring-fencing provisions
(3) Stable financial profile and credit metrics
(4) Strong franchise area, with a predictable customer base

Challenges

(1) ROE level and loss of performance-based rate (PBR) incentive earnings
(2) Volume exposure in the industrial and transportation segments
(3) Long-term competitiveness of natural gas relative to alternative energy sources

Financial Information

	LTM Jun. 30th	*For the year ended December 31st*				
	2011	**2010**	**2009**	**2008**	**2007**	**2006**
EBIT Interest Coverage(1)	1.9x	2.1x	1.9x	1.9x	1.9x	2.0x
% Debt in Capital Structure(1)	60.1%	62.6%	66.4%	66.5%	66.4%	64.8%
Cash Flow/Total Debt(1)	11.2%	10.3%	9.8%	9.6%	8.4%	9.7%
Cash Flow/CapEx	1.1x	1.1x	1.2x	1.4x	1.3x	1.5x
Net Income before Extra. (C$ millions)	74	93	87	92	70	68
Operating Cash Flow (C$ millions)	176	177	170	166	146	160

(1) Includes operating leases

FortisBC Energy Inc.

Report Date:
September 19, 2011

Rating Rationale (Continued from page 1.)

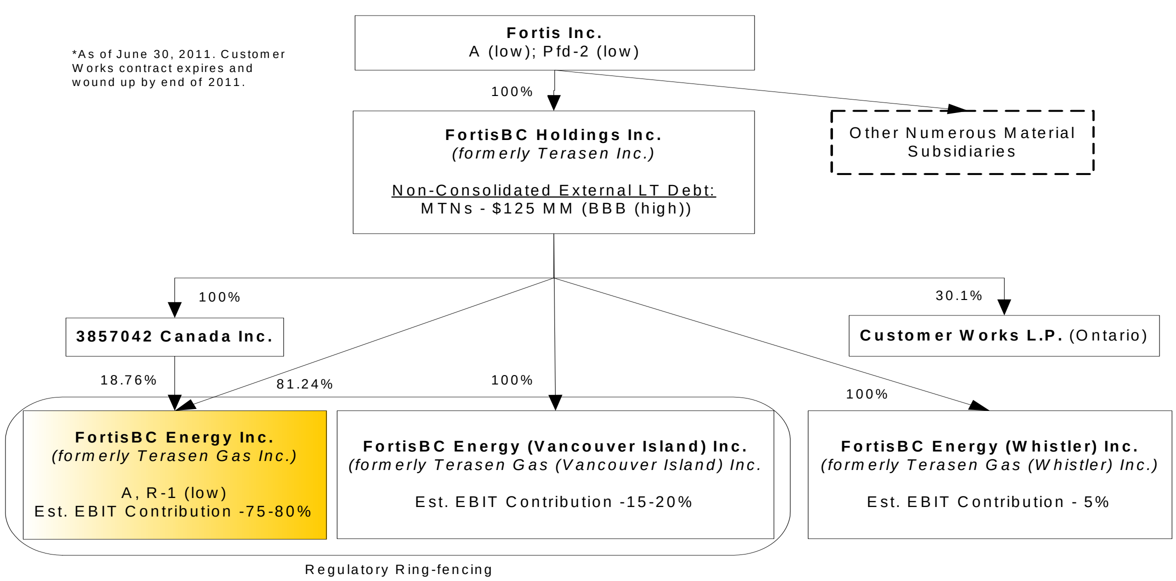
The regulatory environment in which FEI operates continues to provide for a number of cost-recovery mechanisms that, when combined with the general rate-setting methodology, allow for a full recovery of all prudently incurred operating expenses and capital expenditures within a reasonable time frame. In July 2011, the BCUC approved FEI's December 2010 application to provide fuelling station infrastructure and services but denied the Company's request for a general tariff for the provision of natural gas for vehicles unless certain contractual conditions are met. Earlier in May 2011, FEI filed its 2012-2013 Revenue Requirements and Delivery Rate Application (RRA) in which the Company forecasted a rate increase of approximately 2.8% to 3.0% based on an average rate base of roughly $2,740 million to $2,900 million. The outcome is anticipated in the first quarter of 2012.

FEI's operating performance and credit metrics have historically been stable and are expected to continue to remain consistent. Additionally, due to increases in both the approved ROE and equity thickness as a result of regulatory changes in 2009, DBRS anticipates a continued modest lift in the Company's EBIT coverage and cash flow-to-debt metrics, despite the loss of PBR-related earnings. Despite these increases, FEI's key metrics are expected to remain moderately lower than those of similarly rated gas distribution companies, however, DBRS believes that FEI's relatively weaker financial profile is offset by the predictable, low-risk business profile of the Company's business.

The Company is expected to continue to generate minimal-to-modest free cash flow deficits over the medium term due to the need to replace and refurbish existing infrastructure (which is expected to go into the rate base in a timely manner) and respond to modest customer growth. DBRS expects that FEI will continue to finance any deficits with a combination of bank debt, long-term debt issuances and dividend management.

The Company, in conjunction with its holding company, FHI, and its ultimate parent, Fortis Inc. (FTS, rated A (low)), intends to transition to U.S. GAAP, as opposed to IFRS, in January 2012. The BCUC has approved FEI's request to adopt U.S. GAAP to be used for regulatory reporting purposes from January 1, 2012 to December 31, 2014 but has directed the Company to re-apply by September 1, 2014 for approval of its regulatory accounting standard effective January 1, 2015. DBRS anticipates that any impact to the Company's cash flow and cash-flow metrics upon successful conversion of accounting standards will be de minimis.

Simplified Organization Chart*



Rating Considerations Details

Strengths

(1) FEI's low-risk regulated operations are located in a stable regulatory environment which allows the Company to generate predictable earnings and cash flow to sustain and grow its business. Moreover, FEI operates under a full cost-of-service recovery framework and utilizes deferral accounts which further stabilizes earnings and enables the Company to adjust for the recovery/refund of any shortfalls/overages of natural gas costs from/to customers. FEI is not exposed to commodity costs (subject to a degree of recovery lag) as natural gas costs are fully passed on to customers, with quarterly adjustments.

(2) The regulatory ring-fencing imposed by the BCUC on FEI as a condition of the acquisition of FHI by FTS requires, among other conditions: (1) maintenance of the BCUC-approved capital structure; (2) no common dividend payment without BCUC approval if the payment would violate the first condition; (3) no financial support or guarantees for its non-regulated businesses or affiliates; and (4) no transactions with affiliates that would violate BCUC guidelines, policies or directives. The intent of the BCUC decision is to ensure that public interest is protected and that FEI, along with FEVI, will continue to operate as separate, stand-alone entities without undue parental influence.

(3) FEI has historically maintained a stable balance sheet and credit metrics, with some modest improvement attributable to the regulatory changes in 2009. While the EBIT coverage and cash flow-to-debt ratios have improved and are expected to remain at more modestly favourable levels, they remain on the lower end for an A rating compared with its gas distribution peers. However, DBRS remains comfortable with FEI's rating given the inherent low risk nature of its business, and the stability its credit metrics have shown over time.

(4) FEI serves a customer base of approximately 846,000, located in a stable franchise area that includes the City of Vancouver. The customer mix is comprised mainly of residential and commercial customers, which account for roughly 90% of the Company's distribution revenue. Although, there is no volume risk (although there is a degree of recovery lag) associated with these customer segments, DBRS expects the customer growth trend to continue to decline, with fewer new housing starts and a shift in the housing mix to more multi-family dwellings. FEI is expected to focus on retaining customers through expanded energy conservation and efficiency programs in order to offset the growth trend.

Challenges

(1) FEI's earnings and financial profile over the longer term will largely depend on the competitive position of natural gas relative to alternative energy sources (electricity as the primary competitor) in British Columbia. Despite the significant increases in natural gas prices through 2008, natural gas continued to maintain a competitive advantage over electricity in terms of pricing. While gas prices have since retreated, it is expected that under reasonable gas price assumptions, FEI will remain competitive relative to electricity, with electricity prices expected to rise gradually in the medium term, according to British Columbia Hydro & Power Authority (BC Hydro). This current pricing environment improves both FEI's competitiveness and reduces its working capital and liquidity requirements.

(2) The Company is exposed to forecast variances related to its industrial fixed-price contracts and transportation-services segments, which represent approximately 45% of throughput volumes and 5% of revenues but are not eligible for inclusion in the revenue stabilization deferral account. However, this volume risk is mitigated by the fact that usage by these segments is less likely to be significantly affected by weather and is therefore more predictable. FEI also annually surveys its industrial customer segment to minimize forecast variances in throughput volumes. Further mitigating this risk are the fixed demand charges derived from this segment.

(3) In 2009, the BCUC terminated the automatic ROE adjustment formula and set the approved level at 9.50%, however, the ROE had been below 9% for the prior three years, negatively affecting earnings and cash flows. Additionally, under the prior PBR mechanism, FEI shared earnings above or below the allowed ROE on a 50/50 basis with customers. The loss of PBR earnings has largely offset the credit positive impact of the ROE increase.

Regulation

Regulatory Overview

The Company is located in the Province of British Columbia (B.C. or the Province, rated AA (high)) and is regulated by the BCUC on a test-year forecast basis under a rate-of-return/cost-of-service methodology. Under this system, the Company must apply to the BCUC for approval to recover its forecasted cost-of-service from customers through rates. Typically, FEI's cost of service includes the cost of purchased gas, transportation and distribution, operating, maintenance and administrative expenses (OM&A), depreciation of facilities, interests, income, and other taxes and ROE. Accordingly, FEI's rates are based on estimates of items such as natural gas sales volumes, the cost of natural gas and interest rates.

In order to manage the forecast risks associated with these estimates, the Company employs a number of regulatory deferral accounts to mitigate potential impacts:

- **Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA):** Any differences between actual and forecast gas costs are recorded in these deferral accounts to be recovered or refunded in future rates. Consequently, FEI is minimally exposed to recovery lag since balances are expected to be fully recovered or refunded within the next fiscal year, however, prices are adjusted on a quarterly basis to better reflect prevailing gas commodity prices thereby mitigating the impact of recovery lag.
- **Revenue Stabilization Adjustment Account (RSAM):** The RSAM seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in forecast versus actual customer use throughout the year and subsequently recovered in rates over three years. The RSAM stabilizes revenues from residential and commercial customers but variances by large-volume industrial transportation and sales customers, which account for 45% of FEI's total throughput, are not included in this deferral account. However, FEI's exposure to volume risk is mitigated by the predictability in usage of these customer segments that are also less likely to be significantly affected by weather.
- FEI also utilizes short- and long-term interest rate deferral accounts to assist in absorbing the impact of interest rate fluctuations.

FEI is presently operating under a Negotiated Settlement Agreement (NSA) that allows changes to the BCUC-determined ROE (set at 9.50% for 2011) and common equity levels (set at 40.00% for 2011) to be incorporated into rates. Established in late 2009 when the BCUC determined that the ROE adjustment mechanism under which FEI operated no longer applied, the NSA set FEI's rates for 2010 and 2011 but does not include the PBR mechanism that was in effect from 2004 to 2009. Previously under the PBR, the Company's O&M costs as well as base-capital expenditures were subject to an incentive formula that reflected increasing costs due to customer growth and inflation, less a productivity factor.

The PBR had provided for a 50/50 sharing mechanism of earnings above or below the allowed ROE that was set annually according to a formula based on a forecast of 30-year Canada Bonds plus a 3.90% risk premium when the forecast yield is 5.25%. The risk premium was adjusted annually by 75% of the difference between 5.25% and the forecast yield. The common equity component of the capital structure was set at 35.01%; the BCUC has since increase FEI's equity level to 40.00% and the Company received a $125 million equity injection in January 2010 to align its capital structure with this revision. While the loss of the PBR income would have negatively affected FEI's financial results, this was largely offset by an improvement in regulatory allowed ROE (to 9.50% from the 8.43% that would otherwise have been in effect) and equity thickness (from 35.01% to 40%).

Regulatory Ring-Fencing

The regulatory ring-fencing imposed by the BCUC as a condition of the acquisition of FEI by FTS in April 2007 (a continuation of the ring fencing imposed upon acquisition of the former Terasen Inc. by KMI in December 2005) is intended to ensure that public interest is protected and that FEI and FEVI will continue to operate as separate, stand-alone entities without undue parental influence.

Earnings and Outlook

Consolidated Income Statement

(C$ millions)	LTM Jun. 30th 2011	2010	2009	2008	2007	2006
		For the year ended December 31st				
Net Revenue	566	572	526	513	507	517
EBITDA	296	317	297	292	293	301
EBIT	207	226	214	214	215	217
Gross Interest Expense	106	104	109	111	108	106
Pre-tax Income	103	123	106	103	108	112
Income Tax	29	30	19	12	38	44
Core Net Income (before Extra.)	74	93	87	92	70	68
Net Income	74	93	87	92	78	68
Return on Avg. Common Eq. (before Extra.	7.2%	9.8%	9.9%	10.4%	7.9%	7.8%
EBIT Margin (Net of Gas Costs)	36.5%	39.4%	40.7%	41.7%	42.3%	42.0%
Rate Base	2,634	2,540	2,547	2,510	2,484	2,516
Approved common equity	40.00%	40.00%	35.01%	35.01%	35.01%	35.00%
Allowed ROE*	9.50%	9.50%	8.99%	8.62%	8.37%	8.80%

* 8.47% for first six months of 2009, 9.50% for second six months

Summary

Much of the recent modest improvement in FEI's earnings is attributable to the 2009 BCUC decision to increase both the Company's common equity component and approved ROE. Notwithstanding these increases, FEI's earnings continue to remain relatively predictable due to the Company's core segment of residential and commercial customers that comprise the majority of its margin while its industrial customers are typically under contract and are less susceptible to the weather. Moreover, FEI continues to maintain very stable EBITDA and EBIT levels that are reflective of modest net additions to its customer base, increases in its rate base and an established approved equity component, all largely offset by relatively low allowed ROE levels.

Historically, FEI's gas distribution segment has accounted for more than 50% of total throughput volumes and roughly 90% of total revenues. Throughputs for this segment exhibit stability, and any volume risk is mitigated as shortfalls/overages in volume revenues are deferred and recovered/refunded through future rates. However, the growth in multi-family housing continues to negatively impact net customer additions as the use of natural gas is less prevalent within these dwellings.

FEI's transportation segment and industrial customers under fixed-price contracts have historically accounted for approximately 50% of FEI's total throughput volumes and less than 10% of total revenues. Although these segments expose the Company to a degree of volume risk, the exposure is mitigated by the fact that their usage is less likely to be significantly affected by weather and is therefore more predictable. Further mitigating this risk is the fixed demand charges derived from these segments. Interest expense has been relatively stable over the past five years due to fairly consistent levels of total debt.

Outlook

The Company's earnings are anticipated to continue at their modestly higher levels due to the impact of the higher equity component and approved ROE, offset by the negative impact of the loss of incentive earnings upon expiry of the PBR mechanism. DBRS expects that over the medium term, as typical of a mature gas distribution utility, FEI will continue to generate relatively stable earnings, with some variability related to allowed ROE, population growth, new housing starts and customer conversions.

Over the longer term, FEI's earnings will largely depend on the competitiveness of natural gas relative to electricity in British Columbia. While FEI has maintained a competitive advantage in terms of pricing compared with electricity, its competitive position may weaken should gas prices increase significantly for a prolonged period of time, potentially negatively impacting FEI's financial and credit profile. The competitiveness of natural gas may also be affected by the provincial consumption tax on carbon-based fuels.

FortisBC Energy Inc.

Report Date:
September 19, 2011

Financial Profile

Cash Flow Statement

(C$ millions)	*LTM Jun. 30th* 2011	*For the year ended December 31st* 2010	2009	2008	2007	2006
Net Income (before Extra.)	92	93	87	92	70	68
Depreciation & Amortization	89	91	83	78	79	84
Other Non-cash Adjustments	(4)	(7)	0	(4)	(3)	8
Operating Cash Flow	176	177	170	166	146	160
CapEx	(161)	(157)	(139)	(123)	(108)	(109)
Common Dividends	(82)	(84)	(67)	(100)	(111)	(40)
Free Cash Flow Before W/C Changes	(67)	(64)	(36)	(57)	(73)	12
Working Captial Changes	56	(15)	16	33	(28)	83
Net Free Cash Flow	(11)	(79)	(20)	(24)	(101)	95
Acquisitions/Divestitures	0	0	0	14	0	0
Other adjustment/comprehensive	0	0	0	14	0	0
Cash Flow Before Financing	176	177	170	166	146	160
Net Change in Debt Financing	(0)	(24)	6	(5)	89	(98)
Net change in Pref. Share Financing	0	0	0	0	0	0
Net Equity in Financing	0	125	0	0	0	0
Net Change in Cash	1	9	(7)	8	(1)	(9)
Total Adjusted Debt (C$ million)(1)	1,576.0	1,713.3	1,738.9	1,734.4	1,738.6	1,657.6
Cash Flow/Total Debt(1)	11.2%	10.3%	9.8%	9.6%	8.4%	9.7%
% Debt in Capital Structure(1)	60.1%	62.6%	66.4%	66.5%	66.4%	64.8%
EBIT Interest Coverage(1)	1.9	2.1	1.9	1.9	1.9	2.0
Dividend Payout Ratio	111.0%	90.1%	76.8%	109.3%	158.0%	58.5%

(1) Includes operating leases

Summary

As with FEI's earnings, the recent modest increase in the Company's stable cash flow from operations is attributable to the regulatory increases to the ROE and equity thickness in 2009. Dividends will continue to be maintained in line with FEI's BCUC-approved capital structure as, pursuant to the BCUC-imposed ring-fencing conditions, FEI is prohibited from paying dividends unless it has in place at least as much equity as required by the BCUC for rate-making purposes.

Key cash-flow metrics remain moderately lower than those of similarly rated gas distribution peers, however, DBRS believes that FEI's relatively weaker financial profile is offset by the predictable, low-risk business profile of the Company's business and notes that the stability of FEI's coverage metrics continues to be a key factor in its ratings.

Outlook

Historically, FEI's financial profile has been stable and is expected to remain relatively consistent over the medium term, with a continued modest lift in the Company's cash flow-to-debt metrics as a result of the regulatory changes in 2009 and despite the loss of PBR-related earnings. The Company is expected to continue to generate minimal-to-modest free cash flow deficits over the medium term due to the need to replace and refurbish existing infrastructure (which is expected to go into the rate base in a timely manner) and respond to modest customer growth. Capital expenditures are expected to be approximately $180 million annually over the short- to medium-term and DBRS expects that any deficits are to be financed with a combination of the Company's $500 million revolving bank facility ($411.8 million of which was available at June 30, 2011) and long-term debt issuances.

Long term, DBRS believes that, under current reasonable gas and electricity price assumptions, FEI will remain competitive relative to alternative energy sources and anticipates that any impact to the Company's cash flow and cash-flow metrics upon successful conversion of accounting standards will be de minimis. Moreover, DBRS anticipates that the planned amalgamation and associated rate harmonization of FEI, FEVI and FEW will not impact the credit profile of FEI provided that the there are no material changes to the consolidated utility that will negatively affect its deemed capital structure, allowed ROE or fundamental low-risk business model.

Long-Term Debt and Liquidity

DBRS views FEI's liquidity as sufficient for its funding requirements. The Company's $500 million, five-year unsecured committed revolving credit facility with a syndicate of banks matures in August 2013 and $411.8 million was unutilized as at June 30, 2011. The credit facility is primarily used to support FEI's $500 million commercial paper (CP) program and working capital requirements, which vary to a large extent with seasonal gas inventory levels. Typically, gas inventory levels and working capital requirements peak in the fall and winter seasons and decline in the spring and summer.

FEI's debt-repayment schedule is negligible in the near term:

As at June 30, 2011

(C$ millions)	2011	2012	2013	2014	2015	Thereafter	Total
Long-Term Debt	2.6	2.6	2.6	2.6	77.5	1,370.0	1,457.9

DBRS notes that FEI's bond indenture contains an EBIT-to-interest coverage test that must be observed in order for the Company to issue additional indebtedness. To allow FEI to issue debt with a maturity term longer than 18 months, EBIT for the 12 consecutive months out of the previous 23 months must be at least 2.0 times its annual pro forma interest.

FortisBC Energy Inc.

Report Date:
September 19, 2011

FortisBC Energy Inc.

Balance Sheet

(Consolidated)

(C$ millions)	*As at Jun. 30th*	*As at the year ended Dec. 31st*				*As at Jun. 30th*	*As at the year ended Dec. 31st*		
Assets	**2011**	**2010**	**2009**	**2008**	**Liabilities & Equity**	**2011**	**2010**	**2009**	**2008**
Cash	9	15	6	13	Short-term Debt	40	178	204	239
Accounts Receivable	231	298	277	346	Long-term Debt Due within 1 Year	3	3	2	62
Inventories	80	136	149	192	Accounts Payable	280	358	337	366
Prepaid Expenses & Other	14	11	23	3	Tax Payable	65	37	42	66
Rate Stabilization Accounts	61	96	69	54	Rate Stabilization Accounts	33	4	12	24
					Other LT Liabilities & Deferred Dredts	5	12	0	0
Current Assets	395	557	524	608	**Current Liabilities**	427	591	597	755
Net Fixed Assets	2,476	2,466	2,423	2,357	Long-Term Debt	1,444	1,442	1,440	1,340
Rate Stabilization Accounts	0	0	0	0	Deferred Credits	167	149	181	138
Deferred Charges	0	0	0	40	Deferred Taxes	282	280	271	1
Long-Term Investments	492	461	423	104	Common Equity	1,044	1,023	881	875
Total	3,364	3,484	3,370	3,109	**Total**	3,364	3,484	3,370	3,109

Ratio Analysis	*LTM Mar. 31st*	*For the year ended December 31st*				
	2011	**2010**	**2009**	**2008**	**2007**	**2006**
Liquidity Ratios						
Current Ratio	0.93x	0.94x	0.88x	0.80x	0.65x	0.65x
Accum. Depr./Gross Fixed Assets	N/A	25.4%	24.2%	23.4%	23.4%	23.5%
Cash Flow/Total Debt[(1)]	11.2%	10.3%	9.8%	9.6%	8.4%	9.7%
Cash Flow/CapEx	1.09x	1.13x	1.22x	1.35x	1.35x	1.47x
Cash Flow-Dividend/CapEx	0.58x	0.59x	0.74x	0.54x	0.33x	1.11x
Debt in Capital Structure[(1)]	60.1%	62.6%	66.4%	66.5%	66.4%	64.8%
Approved common equity	40.00%	40.00%	35.01%	35.01%	35.01%	35.00%
Common Div. Payout (before Extra.)	111.0%	90.1%	76.8%	109.3%	158.0%	58.5%
Coverage Ratios						
EBIT/Interest Expense[(1)]	1.9x	2.1x	1.9x	1.9x	1.9x	2.0x
EBITDA/Interest Expense[(1)]	2.7x	2.9x	2.6x	2.5x	2.6x	2.8x
Fixed-Charge Coverage[(1)]	1.9x	2.1x	1.9x	1.8x	1.9x	1.9x
Debt/EBITDA	5.3x	5.4x	5.9x	5.9x	5.9x	5.5x
Profitability Ratios						
EBIT Margin, excl. Cost of Gas	36.5%	39.4%	40.7%	41.7%	42.3%	42.0%
Net Margin excl. Preferred Dividends	13.1%	16.3%	16.5%	17.9%	13.8%	13.2%
Return on Avg. Equity (before Prefs)	7.2%	9.8%	9.9%	10.4%	7.9%	7.8%
Allowed ROE[(2)]	9.50%	9.50%	8.99%	8.62%	8.37%	8.80%
Operating Statistics						
Customer Growth	N/A	0.8%	0.6%	1.1%	1.2%	1.3%
Op. Costs/Avg. Customer (C$ millions)	731	353	316	306	303	318
Rate Base (C$ millions)	2,634	2,540	2,547	2,510	2,484	2,516
Rate Base Growth	N/A	-0.3%	1.5%	1.0%	-1.3%	4.6%

(1) Includes operating leases

(2) 8.47% for first six months of 2009, 9.50% for second six months

Operating Statistics	For the year ended December 31st				
	2010	2009	2008	2007	2006
Throughput Volumes					
Residential	65.2	72.7	78.5	74.9	68.7
Commercial	38.8	42.4	44.1	42.3	38.4
Small industrial	2.6	3.0	3.1	3.4	3.8
Large industrial	0.1	0.2	0.1	0.2	0.2
Total Natural Gas Sales Volumes	106.7	118.3	125.8	120.8	111.1
Transportation Service	54.9	54.0	57.3	62.3	62.3
Throughput Under Fixed-price Contracts	33.0	36.0	39.6	36.8	36.8
Total Throughputs (PJs)	194.6	208.3	222.7	219.9	210.2
Customers					
Residential	762,496	755,660	750,838	742,882	733,598
Commercial	81,366	81,274	81,012	79,717	79,113
Small industrial	236	251	284	297	325
Large industrial	25	31	33	40	40
Transportation	2,111	2,075	2,059	2,041	1,956
Total (thousands)*	846,234	839,291	834,226	824,977	815,032

* Increase in throughput volume for F2007 reflects the amalgamation of Terasen Gas (Squamish) Inc. with TGI

FortisBC Energy Inc.

Report Date:
September 19, 2011

Ratings

Debt	Rating	Rating Action	Trend
MTNs & Unsecured Debentures	A	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating History

Debt Rated	Current	2010	2009	2008	2007	2006
MTNs & Unsecured Debentures	A	A	A	A	A	A
Purchase Money Mortgages	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Related Research

- FortisBC Holdings Inc., Rating Report, September 19, 2011.

Notes:
All figures are in Canadian dollars unless otherwise noted.

MOODY'S INVESTORS SERVICE

Credit Opinion: **FortisBC Energy Inc.**

Global Credit Research - 21 Jul 2011

Vancouver, British Columbia, Canada

Ratings

Category	**Moody's Rating**
Outlook	Stable
Senior Secured -Dom Curr	A1
Senior Unsecured -Dom Curr	A3
Parent: FortisBC Holdings Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa2
FortisBC Energy (Vancouver Island) Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3

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Key Indicators

[1]**FortisBC Energy Inc.**

	[2]**LTM**	**2010**	**2009**	**2008**	**2007**	**2006**
(CFO Pre-W/C + Interest) / Interest Expense	**2.7x**	**2.7x**	**2.6x**	**2.5x**	**2.4x**	**2.5x**
(CFO Pre-W/C) / Debt	**11.3%**	**10.6%**	**10.2%**	**9.8%**	**8.8%**	**10.1%**
(CFO Pre-W/C - Dividends) / Debt	**5.4%**	**5.9%**	**6.5%**	**4.2%**	**2.5%**	**7.7%**
Debt / Book Capitalization	**57.3%**	**59.1%**	**61.8%**	**68.4%**	**66.8%**	**65.2%**

[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] Last twelve months ended March 31, 2011

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low-risk, cost-of-service regulated gas transmission and distribution utility

Weak financial metrics balanced by a supportive regulatory environment

Strong regulatory ring-fencing mechanisms insulate company from its weaker parent

Sufficient liquidity resources

Corporate Profile

FortisBC Energy Inc. (FEI) is the largest distributor of natural gas in British Columbia and one of the largest gas local distribution companies (LDC) in Canada. FEI is regulated on a cost-of-service basis by the British Columbia Utilities Commission (BCUC).

FEI is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI) which, in turn, is a wholly-owned subsidiary of Fortis Inc. (FTS, not rated), a diversified electric and gas utility holding company. FHI is a holding company which also holds 100% of FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) as well as a 30% interest in CustomerWorks, L.P.

SUMMARY RATING RATIONALE

FEI's A3 senior unsecured rating and stable outlook reflect its low-risk LDC business model and supportive regulatory environment which are balanced by its weak financial metrics. We recognize that the weakness of FEI's financial metrics relative to similarly rated U.S. peers is largely a function of the relatively lower deemed equity and allowed ROE permitted by the BCUC. We believe that FEI's weak financial profile is balanced by its relatively low business risk as a gas LDC and the by the supportiveness of the business and regulatory environments in Canada generally and in British Columbia specifically. We expect FEI's financial profile to strengthen modestly in 2012 and 2013. Regulatory ring-fencing mechanisms effectively insulate FEI from its weaker parent companies, FHI and FTS. Growth in FEI's franchise area tends to be predictable and capital spending is not expected to tax the company's resources. FEI maintains sufficient liquidity resources.

DETAILED RATING CONSIDERATIONS

LOW-RISK REGULATED GAS DISTRIBUTION UTILITY OPERATING IN A SUPPORTIVE ENVIRONMENT

In general, we consider gas LDCs to be at the low end of the risk spectrum within the universe of regulated utilities. Similarly, we believe that regulated utilities, which are permitted the opportunity to recover their costs and earn an allowed return, have lower business risk than unregulated companies that do not benefit from cost of service regulation. Accordingly, we consider regulated gas LDCs like FEI to be among the lowest risk corporate entities.

We consider Canada to have more supportive regulatory and business environments than other jurisdictions globally. Furthermore, the regulatory environment in the Province of British Columbia (BC) is considered one of the most supportive in Canada reflecting the fact that regulatory proceedings in BC tend to be less adversarial than those in other jurisdictions and decisions tend to be timely and balanced. The supportiveness of the BC regulatory environment is also evidenced by the fact that FEI benefits from the existence of a number of BCUC-approved deferral, or true up, mechanisms. These mechanisms limit FEI's exposure to forecast error with respect to commodity price and volume, pension funding costs, insurance costs and short-term interest rates. In addition, FEI is required to obtain a certificate of public convenience and necessity (CPCN) from the BCUC prior to undertaking any capital project in excess of $5 million. In our view, this process reduces the risk that FEI would be denied the opportunity to recover the cost of its capital investments. We believe these qualitative factors balance FEI's weak financial profile.

Growth in FEI's franchise area tends to be relatively predictable and capital spending is generally stable and modest in the context of FEI's asset base and depreciation expense. That said, we expect capital spending to be higher in 2011 than it has been in recent years. This reflects certain non-recurring or infrequently occurring projects such as the development of a new customer care system and the upgrading of a major river crossing. Notwithstanding higher capital spending in 2011, we anticipate that FEI will continue to finance its capital spending with a prudent combination of internally generated funds, additional term debt and equity injections from FTS as required.

FINANCIAL METRICS EXPECTED TO STRENGTHEN MODESTLY IN 2012 and 2013

FEI's financial metrics are materially weaker than those of its A3 rated global gas utility peers such as Piedmont Natural Gas Company, Inc., Northwest Natural Gas Company, UGI Utilities and its sister company, FEVI. We recognize that FEI's weaker financial metrics are largely a function of the deemed equity and allowed ROE approved by the BCUC. In general, Canadian deemed equity ratios and allowed ROEs are low relative to those of other jurisdictions.

We expect FEI's cash flow to increase in 2012 and 2103 due to higher levels of non-cash depreciation and amortization expense that will be collected in revenues. The largest driver of the higher depreciation will be FEI's customer care enhancement project which is slated to be placed into service in 2012. We anticipate that these changes will cause CFO pre-WC + Interest / Interest (Cash Flow Interest Coverage) to approach 3x in 2012 and 2013 versus the mid 2x range in recent years. Similarly, we anticipate CFO pre-WC / Debt will exceed 10% in the future versus its approximately 10% level in the past few years.

POTENTIAL AMALGAMATION OF FEI, FEVI AND FEW LIKELY CREDIT NEUTRAL

FEI has indicated that during 2011 it intends to apply to the BCUC to amalgamate FEI, FEVI and FEW and harmonize rates across the amalgamated utility. In an amalgamation scenario, the senior unsecured debt of FEI and FEVI would rank pari passu and be supported by the combined cash flow of the amalgamated utility. While the timing and outcome of the planned amalgamation application are unknown at this time, we expect that amalgamation and rate harmonization would be credit neutral to FEI provided that there are no reductions in deemed equity levels or allowed ROE or increases in the fundamental business risks borne by the amalgamated utility.

STRONG REGULATORY RING-FENCING INSULATES FEI FROM PARENT, FHI

We believe that FEI's ring-fencing is very good relative to that of its peers outside of BC. FEI is subject to a set of regulatory ring-fencing conditions imposed by the BCUC. The ring-fencing conditions provide that, unless otherwise approved by the BCUC, FEI shall: maintain a ratio of common equity to total capital at least as high as the deemed equity capitalization utilized by the BCUC for ratemaking purposes (currently 40%); not pay dividends if they would cause FEI's common equity to total capital to fall below the BCUC's deemed equity percentage; not invest in or financially support any non-regulated business; and not engage in affiliate transactions on anything other than an arm's length basis. We believe that the BCUC ring-fencing provisions effectively insulate FEI from the greater financial and business risks of its parents, FHI and FTS. The regulatory ring-fencing provisions, combined with FTS' philosophy of requiring its utility operating subsidiaries to be operationally and financially independent of FTS and other subsidiaries, allow us to evaluate FEI's credit profile on a stand-alone basis.

Liquidity Profile

We expect FEI's liquidity will be sufficient to meet its funding requirements over the next four quarters.

We expect FEI to generate approximately $215 million of CFO pre-WC during the 12 months ending June 30, 2012. After dividends in the range of $85 million and capital expenditures and working capital changes of approximately $255 million, we expect FEI to be free cash flow (FCF) negative by approximately $125 million. FEI has no material scheduled debt maturities during the twelve months ending June 30, 2012 resulting in a funding requirement of approximately $125 million.

We estimate availability under FEI's credit agreement to be roughly $380 million which exceeds our $125 million estimate of the company's funding requirement.

FEI's $500 million syndicated committed revolving facility matures August 2013 and is available to support its $500 million commercial paper (CP) program and for general corporate purposes. The company is currently well below the debt to total capitalization ratio covenant (maximum

75%) in the credit agreement. Further, the syndicated credit agreement does not contain language such as Material Adverse Change (MAC) clauses or ratings triggers that would inhibit access to the unutilized portion of the facility in situations of financial stress.

Although utilization of FEI's credit facility was limited to roughly $134 million at March 31, 2011, during the peak gas storage season the financing of gas inventory can significantly reduce the unutilized portion of FEI's credit facility. For instance, at the end of the third quarter of 2008, availability under FEI's $500 million credit facility was only about $175 million. We recognize that FEI's reliance on short-term debt to finance gas inventories is supported by the BCUC and that the BCUC has approved the use of an interest rate deferral account to limit FEI's exposure to short-term interest rate volatility. However, we believe that FEI's financial flexibility can become somewhat constrained, particularly, when material debt maturities fall within the peak storage season. Although FEI has no significant debt maturities until September 2015, the BCUC's July 2011 decision to eliminate the majority of FEI's commodity hedging activities is expected to increase the volatility of FEI's cash flow and increase FEI's liquidity requirements. This decision is directionally negative for credit but, at this time, not material enough to impact our rating or outlook.

Rating Outlook

The stable outlook is predicated on FEI's low business risk as a regulated gas LDC, our expectation that FEI's regulatory environment will continue to be supportive and our belief that FEI's financial profile will continue to improve modestly through 2013. The outlook also reflects our belief that if FEI, FEVI and FEW ultimately amalgamate, the amalgamation and rate harmonization would be credit neutral for FEI's credit profile.

What Could Change the Rating - Up

We consider an upward revision in FEI's rating to be unlikely in the near term due to its weak financial profile. However, the rating could be positively impacted if FEI could demonstrate a sustainable improvement in its credit metrics. All else being equal, at the A2 senior unsecured level, Moody's would expect FEI's Cash Flow Interest Coverage to exceed 4x and CFO pre-WC / Debt to be above 19%.

What Could Change the Rating - Down

Notwithstanding FEI's low risk business profile, its financial profile is considered weak at the A3, senior unsecured rating level. Accordingly, a sustained weakening of FEI's Cash Flow Interest Coverage below 2.3x and CFO pre-WC / Debt below 8% combined with a less supportive and predictable regulatory framework would likely result in a downgrade of FEI's rating. This could occur if gas were to lose its competitive advantage over electricity in British Columbia due Provincial policies favouring non-carbon emitting energy sources or other factors.

Rating Factors

FortisBC Energy Inc.

Regulated Electric and Gas Utilities Industry [1][2]	**Current**		[3]**Moody's 12-18 month Forward View As of 07/20/2011**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		Aa		Aa
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: Fin. Strength, Liquidity And Key Fin. Metrics (40%)				
a) Liquidity (10%)		A		A
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	2.6x	Ba1	2.6x-2.8x	Ba1/Baa3
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	10.2%	Ba2	9%-11%	Ba2/Ba1
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	5.5%	Ba2	5%-7%	Ba2/Ba1
e) Debt/Capitalization (3 Year Avg) (7.5%)	62.9%	Ba3	57%-60%	Ba2/Ba1
Rating:				
a) Indicated Baseline Credit Assessment from Methodology Grid		A3		A3
b) Actual Baseline Credit Assessment Assigned		A3		A3

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.

of the issuer or any form of security that is available to retail investors. It would be dangerous for retail investors to make any investment decision based on this credit rating. If in doubt you should contact your financial or other professional adviser.

MOODY'S INVESTORS SERVICE

Credit Opinion: FortisBC Energy (Vancouver Island) Inc.

Global Credit Research - 01 Aug 2011

Canada

Ratings

Category	**Moody's Rating**
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Parent: FortisBC Holdings Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa2
Parent: FortisBC Energy Inc.	
Outlook	Stable
Senior Secured -Dom Curr	A1
Senior Unsecured -Dom Curr	A3

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Key Indicators

[1]**FortisBC Energy (Vancouver Island) Inc.**

	[2]**LTM**	**2010**	**2009**	**2008**	**2007**
(CFO Pre-W/C + Interest) / Interest Expense	**4.4x**	**4.5x**	**4.0x**	**4.0x**	**3.8x**
(CFO Pre-W/C) / Debt	**15.6%**	**14.7%**	**13.3%**	**15.5%**	**13.5%**
(CFO Pre-W/C - Dividends) / Debt	**10.3%**	**9.6%**	**8.7%**	**11.8%**	**8.6%**
Debt / Book Capitalization	**62.3%**	**63.3%**	**60.7%**	**66.4%**	**67.2%**

[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] Last twelve months ended March 31, 2010

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Regulated gas local distribution company (LDC) with no unregulated operations

High cost of service and small size balanced by long history of political and regulatory support

Loss of provincial royalty payments at end of 2011 will necessitate higher rates or rate harmonization with FortisBC Energy Inc.

Higher rates would reduce relative competitiveness of gas relative to electricity and potentially lead to a cycle of demand destruction and rate increases

Rate harmonization would improve relative competitiveness of gas

Capex expected to moderate significantly by 2013

Strong regulatory ring-fencing mechanisms

Weak liquidity

Corporate Profile

FortisBC Energy (Vancouver Island) Inc. (FEVI) is a gas LDC serving approximately 100,000 customers on Vancouver Island and the Sunshine

Coast in the province of British Columbia (BC). FEVI, which has no unregulated operations, is regulated on a cost of service basis by the British Columbia Utilities Commission (BCUC). FEVI, which has a forecasted 2012 rate base of approximately $788 million, is one of the smallest gas utilities that we rate.

FEVI is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI), a holding company which also owns 100% of FortisBC Energy Inc. (FEI, A3 senior unsecured) and FortisBC Energy (Whistler) Inc. (FEW, unrated). FHI has been a wholly-owned subsidiary of Fortis Inc. (FTS, unrated) since May 17, 2007.

SUMMARY RATING RATIONALE

FEVI's A3 senior unsecured rating and stable outlook reflect FEVI's status as a regulated gas LDC. However, FEVI's high cost of service and small size cause its business risk to be higher than that of most gas LDCs. In addition, FEVI's credit metrics are weaker than those of international peers. However, we consider FEVI's high cost of service, small size and weak metrics to be balanced by the relatively supportive business and regulatory environments in Canada in general and FEVI's long history of supportive regulatory and political decisions in particular.

The rating also reflects our belief that FEVI's cash flow and financial metrics will be significantly weaker in 2012 due to the scheduled cessation of royalty revenues from the Province of British Columbia at the end of 2011. We believe the weakness in FEVI's metrics will be short-lived because the company will either merge and harmonize rates with sister gas LDC, FEI, causing FEVI's rates to fall or increase its rates to offset the cessation of the royalty revenue. While a significant increase in FEVI's rates would be positive for FEVI's cash flow and financial metrics, it would reduce the relative competitiveness of gas versus electricity in FEVI's service territory. If an increase in FEVI's rates were to lead to a cycle of demand destruction and further rate increases, we continue to believe that amalgamation and rate harmonization, with FEI would be the most likely outcome.

FEVI's A3 rating is consistent with the A3 rating implied by Moody's Regulated Electric and Gas Utilities Rating Methodology.

DETAILED RATING CONSIDERATIONS

SMALL SIZE AND HIGH COST OF SERVICE BALANCED BY HISTORY OF STRONG POLITICAL AND REGULATORY SUPPORT

FEVI's system has a high capital cost per customer and since inception FEVI has relied heavily on regulatory and political support to ensure that its rates have been competitive with the costs of other forms of energy. FEVI's high capital costs per customer reflect the significant investment in transmission infrastructure required to reach its relatively small customer base on the Sunshine Coast and Vancouver Island and its lower market penetration relative to other gas LDCs including FEI.

We consider Canada to have supportive regulatory and business environments relative to other jurisdictions globally. We consider the regulatory environment in BC to be one of the more supportive in Canada since regulatory proceedings tend to be less adversarial and decisions tend to be timely and balanced. In addition, FEVI benefits from a number of mechanisms agreed to by the BC Government and the BCUC that were designed to ensure that FEVI's gas rates were roughly cost competitive with electricity and fuel oil.

Firstly, FEVI's rates have historically been capped such that the cost of gas has been similar to the cost of alternative forms of energy. Secondly, the provincial government has subsidized consumers' gas costs by providing FEVI with royalty revenue payments under the Vancouver Island Natural Gas Pipeline Agreement (VINGPA). In accordance with the terms of the VINGPA, the royalty payments to FEVI cease at the end of 2011. Thirdly, both the Province and the Federal Government have provided FEVI with non-interest bearing loans.

Prior to 2003, FEVI's rates were insufficient to cover FEVI's costs of service and the shortfall was deferred in the Revenue Deficiency Deferral Account (RDDA). In 2003, FEVI reached a point where, with the benefit of the provincial royalty revenues, it was able to recover more than its costs of service and therefore begin to recover the accumulated regulatory assets (principally the RDDA) while charging rates that were roughly competitive with costs of alternative sources of energy on Vancouver Island. By late 2009, FEVI had fully recovered the RDDA and began to accumulate revenue surpluses.

SCHEDULED EXPIRY OF ROYALTY REVENUES PRESSURES NEAR-TERM FINANCIAL METRICS AND MEDIUM-TERM COMPETITIVENESS

In accordance with the VINGPA, the provincial royalty revenues (approximately $20 million in 2011) will cease at the end of 2011. We do not expect FEVI to immediately increase its rates to offset the loss of this cash flow because, subject to BCUC approval, the company plans to amortize the revenue surplus that it has accumulated since 2009. The accumulated revenue surplus, approved by the BCUC as a means of promoting rate stability, is expected to exceed $50 million by the end of 2011. While the amortization of this regulatory liability will allow FEVI to earn its allowed ROE on an accrual accounting basis, it does nothing to offset the loss of royalty revenue cash flows. Accordingly, we expect FEVI's cash flow and financial metrics to weaken materially in 2012.

In the absence of amalgamation and rate harmonization, discussed below, once the accumulated revenue surplus has been fully amortized, FEVI will need to increase rates significantly in order to cover its costs of service. While such a rate increase would allow FEVI to earn its allowed return on equity and would strengthen its cash flow credit metrics, it would reduce the relative competitiveness of gas versus other forms of energy, principally electricity, in FEVI's service territory. Although we expect BC electricity prices to continue to rise at rates well in excess of inflation for the foreseeable future, we note that the provincial government is once again reviewing the operations of British Columbia Hydro and Power Authority (BCH, Aaa) with a view to finding the right balance between required investments and rate increases. Similarly, while we currently anticipate that gas prices will remain relatively low for the foreseeable future, we are cognizant of the historical volatility of gas prices and the fact that current prices are low relative to those that prevailed during much of the preceding decade. Accordingly, there is a risk that significant increases in FEVI's delivery rates combined with higher gas commodity costs could cause gas to be uncompetitive with electricity which could lead to a cycle of demand destruction and further gas rate increases.

FEVI AND FEI PLAN TO SEEK APPROVAL TO AMALGAMATE AND HARMONIZE RATES

In their combined 2012-2013 revenue requirements application, filed with the BCUC on May 4, 2011, FEVI and FEI stated that they plan to apply to the BCUC in 2011 for permission to amalgamate and harmonize their rates effective January 1, 2013. In addition to BCUC approval, the utilities would also require the approval of the provincial government to amalgamate.

While we cannot predict the outcome of this effort, we continue to believe that the Province of British Columbia would be supportive if rate harmonization were ultimately required to preserve the competitiveness of gas in FEVI's service territory. The Province has long provided financial and regulatory support to FEVI in order to promote its policy goal of ensuring availability of gas on Vancouver Island. While Provincial support of amalgamation/rate harmonization is not assured, it is our view that it is unlikely that the Province would simply stand by and allow the Vancouver Island gas distribution infrastructure to falter and fail given the Province's well established track-record of supporting the development of FEVI's franchise. We also note that there is a precedent for such a transaction within the Fortis group of companies: in November 2006, Terasen Gas (Squamish) Inc. was amalgamated with FEI and the rates of the two entities were harmonized. While FEVI is considerably larger than Terasen Gas (Squamish) Inc., we believe the Squamish transaction is a positive precedent.

COMPLETION OF MAJOR CAPITAL PROJECTS WILL RESULT IN A SIGNIFICANT EQUITY INJECTION AND REDUCTION IN CAPEX

FEVI will complete two major projects during 2011 and 2012: the Mt. Hayes liquefied natural gas storage facility and the internalization of its customer care system. On completion of these projects we expect FTS/FHI to inject significant equity into FEVI to bring its actual capital structure in line with its deemed 60/40 capital structure for rate-making purposes. We expect that that equity injections will cause FEVI's debt to capital to fall into the low 50% range in 2011 from about 63% in 2010.

Once in service in 2011, the Mt. Hayes project will provide FEVI with a new stream of cash flow. Under a BCUC-approved long-term contract, FEI is obligated to pay for roughly two thirds of the cost of the Mt. Hayes facility.

While the completion of these major projects will generate incremental cash flow and reduce FEVI's free cash flow shortfall, we do not expect the incremental cash flow to offset the cessation of provincial royalty revenues in 2011.

STRONG REGULATORY RING-FENCING SEPARATES FEVI FROM PARENT COMPANIES

We believe that FEVI's ring-fencing is very good relative to that of its peers outside of BC. FEVI is subject to a set of regulatory ring-fencing conditions imposed by the BCUC. The ring-fencing conditions provide that, unless otherwise approved by the BCUC, FEVI shall: maintain a ratio of common equity to total capital at least as high as the deemed equity capitalization utilized by the BCUC for ratemaking purposes (currently 40%); not pay dividends if they would cause FEVI's common equity to total capital to fall below the BCUC's deemed equity percentage; not invest in or financially support a non-regulated business; and not engage in affiliate transactions on anything other than an arm's length basis. We believe that the BCUC ring-fencing provisions effectively insulate FEVI from the greater financial and business risks of its parents, FHI and FTS. The regulatory ring-fencing provisions combined with FTS' philosophy of requiring its utility operating subsidiaries to be operationally and financially independent of FTS and other subsidiaries, allow us to evaluate FEVI's credit profile on a stand-alone basis.

Liquidity Profile

We consider FEVI's liquidity resources to be weak pending a renegotiation or extension of its primary credit facility which is currently scheduled to mature on April 30, 2012.

FEVI is expected to generate approximately $58 million of CFO pre-WC during the 12 months ending June 30, 2012. After dividends in the range of $24 million and capital expenditures and working capital changes of about $66 million, we expect FEVI to be free cash flow negative by approximately $32 million. Since FEVI has no scheduled debt maturities during this period, we estimate that it will have a funding requirement of approximately $32 million.

While we estimate that availability under FEVI's $300 million syndicated committed revolving credit agreement is more than $200 million and well in excess of FEVI's funding requirement, the credit facility is currently scheduled to expire on April 30, 2012 which is inside the 12 month horizon of our liquidity stress scenario. Accordingly, we consider FEVI's liquidity to be weak. We expect that FEVI will seek to extend the term of this facility to at least December 31, 2012 in light of the company's announced plan to pursue amalgamation with FEI and FEW effective January 1, 2013. With the completion of the Mt. Hayes project in 2011 and the internalization of the customer care system in 2012, FEVI's future capital expenditures will be materially lower than those of recent years so we anticipate that FEVI might downsize the syndicated credit facility as it did in 2010 when the facility was reduced to $300 million from $350 million.

The $300 million credit agreement contains a single maintenance covenant (debt to equity not greater than 70%). As at December 2010, FEVI's leverage was 61.7% leaving reasonable headroom under the covenant. FEVI's credit agreement does not contain language such as a Material Adverse Change (MAC) clause or ratings triggers that would inhibit access to the unutilized portion of the facility in situations of financial stress.

Rating Outlook

The stable outlook reflects our expectation that the anticipated weakness in FEVI's cash flow and financial ratios will be short-lived. We continue to believe that if a cycle of demand destruction and rate increases were to arise, amalgamation of FEVI, FEI and FEW and the harmonization of rates across the various service territories would be the logical outcome.

What Could Change the Rating - Up

We consider it highly unlikely that FEVI's rating would be upgraded in the foreseeable future. However, an upgrade to A2 would require a combination of materially stronger metrics, improved competitiveness and improved liquidity. We would expect to see CFO pre-WC Interest Coverage in excess of 4.5x; CFO pre-WC/Debt approaching 20% and Retained Cash Flow (RCF)/Debt in the low teens on a sustainable basis. This is unlikely to occur in the absence of significant increases in FEVI's deemed equity and allowed ROE. In the absence of material decreases in gas commodity prices, which we do not believe is likely, significant increases in FEVI's deemed equity and allowed ROE would require rate increases which would exacerbate its already existing competitiveness challenges.

What Could Change the Rating - Down

A downgrade to Baa1 would likely be caused by changes in political and/or regulatory policy that disadvantages gas relative to electricity and causes a weakening of FEVI's financial metrics. For instance, CFO pre-WC Interest Coverage in the low 3x range; CFO pre-WC/Debt in the low teens and RCF/Debt in the mid single digit range on a sustained basis.

Rating Factors

FortisBC Energy (Vancouver Island) Inc.

Regulated Electric and Gas Utilities Industry [1]	[2]**Current**		[3]**Moody's 12-18 month Forward View As of 07/26/2011**	
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		Aa		Aa
Factor 3: Diversification (10%)				
a) Market Position (10%)		Baa		Baa
b) Generation and Fuel Diversity (0%)				
Factor 4: Fin. Strength, Liquidity And Key Fin. Metrics (40%)				
a) Liquidity (10%)		A		Ba
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	4.2x	Baa1	2.6x-3.4x	Ba1-Baa2
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	14.5%	Baa3	10%-16%	Ba1-Baa3
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	10.0%	Baa3	5%-10%	Ba2-Baa3
e) Debt/Capitalization (3 Year Avg) (7.5%)	63.4%	Ba3	52%-55%	Baa3
Rating:				
a) Indicated Baseline Credit Assessment from Methodology Grid		A3		A3
b) Actual Baseline Credit Assessment Assigned		A3		A3

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.

MOODY'S INVESTORS SERVICE

Credit Opinion: FortisBC Energy Inc.

Global Credit Research - 04 Oct 2012

Vancouver, British Columbia, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Secured -Dom Curr	A1
Senior Unsecured -Dom Curr	A3
Parent: FortisBC Holdings Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa2
FortisBC Energy (Vancouver Island) Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3

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Key Indicators

[1]**FortisBC Energy Inc.**

	[2]LTM	2011	2010	2009	2008	2007
(CFO Pre-W/C + Interest) / Interest Expense	2.9x	2.8x	2.7x	2.6x	2.5x	2.4x
(CFO Pre-W/C) / Debt	11.6%	11.2%	10.6%	10.2%	9.8%	8.8%
(CFO Pre-W/C - Dividends) / Debt	7.1%	6.5%	5.9%	6.5%	4.2%	2.5%
Debt / Book Capitalization	47.3%	59.3%	59.1%	61.8%	68.4%	66.8%

[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] Last twelve months ended June 30, 2012 reflect changes to US-GAAP whereas prior years are reported under Canadian GAAP. Goodwill is included on FEI's balance sheet with the most notable impact on Debt/Book Capitalization ratios

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low-risk, cost-of-service regulated gas transmission and distribution utility

Relatively weak financial metrics balanced by a supportive regulatory environment

Potential amalgamation of FortisBC Energy Inc. with its sister LDCs

Strong regulatory ring-fencing mechanisms insulate company from its parent holding company

Good liquidity

Corporate Profile

FortisBC Energy Inc. (FEI) is the largest distributor of natural gas in British Columbia and one of the largest gas local distribution companies (LDC) in Canada. FEI is regulated on a cost-of-service basis by the British Columbia Utilities Commission (BCUC).

FEI is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI) which, in turn, is a wholly-owned subsidiary of Fortis Inc. (FTS, not rated), a diversified electric and gas utility holding company. FHI is a holding company which also holds 100% of FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW).

SUMMARY RATING RATIONALE

FEI's A3 senior unsecured rating and stable outlook reflect its low-risk LDC business model and the generally supportive regulatory environment offset by its relatively weak financial metrics. We recognize that the weakness of FEI's financial metrics relative to similarly rated U.S. peers is largely a function of the lower deemed equity and ROE permitted by the BCUC. We believe that FEI's weak financial profile is balanced by its relatively low business risk as a gas LDC and by the supportiveness of regulatory environments in Canada generally and in British Columbia specifically. Regulatory ring-fencing mechanisms effectively insulate FEI from its parent company, FHI, and FTS. Growth in FEI's franchise area tends to be relatively predictable and capital spending is not expected to tax the company's resources. FEI maintains sufficient liquidity resources.

DETAILED RATING CONSIDERATIONS

LOW-RISK REGULATED GAS DISTRIBUTION UTILITY OPERATING IN A SUPPORTIVE ENVIRONMENT

In general, we consider gas LDCs to be at the low end of the risk spectrum within the universe of regulated utilities. Similarly, we believe that regulated utilities, which are permitted the opportunity to recover their costs and earn an allowed return, have lower business risk than unregulated companies that do not benefit from cost of service regulation. Accordingly, we consider regulated gas LDCs like FEI to be among the lowest risk corporate entities.

The supportiveness of the BC regulatory environment is evidenced by the fact that FEI benefits from the existence of a number of BCUC-approved deferral, or true up, mechanisms. These mechanisms limit FEI's exposure to forecast error with respect to commodity price and volume, pension funding costs, insurance costs and short-term interest rates. In addition, FEI is required to obtain a certificate of public convenience and necessity (CPCN) from the BCUC prior to undertaking any capital project in excess of $5 million. In our view, this process reduces the risk that FEI would be denied the opportunity to recover the cost of its capital investments. We believe these qualitative factors balance FEI's weak financial profile.

Growth in FEI's franchise area tends to be relatively predictable and capital spending is generally stable and modest in the context of FEI's asset base and depreciation expense.

FINANCIAL METRICS EXPECTED TO STRENGTHEN MODESTLY IN 2012 and 2013

FEI's financial metrics are materially weaker than those of its A3 rated global gas utility peers such as Piedmont Natural Gas Company, Inc., Northwest Natural Gas Company, UGI Utilities and its sister company, FEVI. We recognize that FEI's weaker financial metrics are largely a function of the deemed equity and allowed ROE approved by the BCUC. In general, Canadian deemed equity ratios and allowed ROEs are low relative to those of other jurisdictions.

We expect FEI's cash flow to increase in 2012 and 2013 due to higher levels of non-cash depreciation and amortization expense that will be collected in revenues. The largest driver of the higher depreciation will be FEI's customer care enhancement project placed into service this year. We anticipate that these changes will cause CFO pre-WC + Interest / Interest (Cash Flow Interest Coverage) to approach 3x in 2012 and 2013. The change in the Debt/Book Capitalization ratio is merely a function of US-GAAP accounting rules as goodwill associated with the Fortis Inc. acquisition in 2007 is now recognized as an asset on FEI's balance sheet with an offset to paid-in capital.

POTENTIAL AMALGAMATION OF FEI, FEVI AND FEW LIKELY CREDIT NEUTRAL

FEI applied earlier this year to the BCUC to amalgamate FEI, FEVI and FEW and harmonize rates across the amalgamated utility with a decision expected in early 2013. In an amalgamation scenario, the senior unsecured debt of FEI and FEVI would rank pari passu and be supported by the combined cash flow of the amalgamated utility. We expect that amalgamation and rate harmonization would be credit neutral to FEI provided that there are no reductions in deemed equity levels or allowed ROEs or increases in the fundamental business risks borne by the amalgamated utility.

STRONG REGULATORY RING-FENCING INSULATES FEI FROM PARENT, FHI

We believe that FEI's ring-fencing is very strong relative to that of its peers outside of BC. FEI is subject to a set of regulatory ring-fencing conditions imposed by the BCUC. The ring-fencing conditions provide that, unless otherwise approved by the BCUC, FEI shall: maintain a ratio of common equity to total capital at least as high as the deemed equity capitalization utilized by the BCUC for ratemaking purposes (currently 40%); not pay dividends if they would cause FEI's common equity to total capital to fall below the BCUC's deemed equity percentage; not invest in or financially support non-regulated business; and not engage in affiliate transactions on anything other than an arm's length basis. We believe that the BCUC ring-fencing provisions effectively insulate FEI from the financial and business risks of its parent, FHI, and FTS. The regulatory ring-fencing provisions, combined with FTS' philosophy of requiring its utility operating subsidiaries to be operationally and financially independent of FTS and other subsidiaries, allows us to evaluate FEI's credit profile on a stand-alone basis.

Liquidity Profile

We consider FEI's liquidity resources to be good at the end of Q2 2012.

FEI is expected to generate approximately $240 million of CFO pre-WC during the 12 months ending June 30, 2013. After dividends in the range of $85 million and capital expenditures and working capital changes of approximately $200 million, we expect FEI to be free cash flow (FCF) negative by approximately $45 million. FEI has no material scheduled debt maturities during the next twelve months..

At the end of Q2 FEI had $449 million available under its $500 million syndicated credit facility, well in excess of our estimated funding requirement.

The $500 million facility is available to support FEI's $500 million commercial paper (CP) program and for general corporate purposes. The company is currently well below the debt to total capitalization ratio covenant (maximum 75%) in the credit agreement.

We recognize that FEI's reliance on short-term debt to finance gas inventories is supported by the BCUC and that the BCUC has approved the use of an interest rate deferral account to limit FEI's exposure to short-term interest rate volatility. However, we believe that FEI's financial flexibility can become somewhat constrained, particularly when material debt maturities fall within the peak storage season. Although FEI has no significant debt maturities until September 2015, the BCUC's July 2011 decision to eliminate the majority of FEI's commodity hedging activities is expected to increase the volatility of FEI's cash flow and increase FEI's liquidity requirements. This decision is directionally negative for credit but, at this time, not material enough to impact our rating or outlook.

Rating Outlook

The stable rating outlook reflects our expectation of stable operating results and our belief that FEI's regulatory environment will continue to be supportive. The outlook also reflects our belief that if FEI, FEVI and FEW ultimately amalgamate, the amalgamation and rate harmonization would be credit neutral for FEI's credit profile.

What Could Change the Rating - Up

The rating could be positively impacted if FEI demonstrates a sustainable improvement in its credit metrics. All else being equal, at the A2 senior unsecured level, Moody's would expect FEI's Cash Flow Interest Coverage to exceed 4x and CFO pre-WC / Debt to be above 19% on a sustainable basis.

What Could Change the Rating - Down

Notwithstanding FEI's low risk business profile, its financial profile is considered relatively weak at the A3 senior unsecured rating level. Accordingly, a sustained weakening of FEI's Cash Flow Interest Coverage below 2.3x and CFO pre-WC / Debt below 8% combined with a less supportive and predictable regulatory framework would likely result in a downgrade of FEI's rating.

Rating Factors

FortisBC Energy Inc.

Regulated Electric and Gas Utilities Industry [1][2]	**Current**		[3]**Moody's 12-18 month Forward View As of September 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 (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%)	2.8x	Baa	2.8x-3.0x	Baa
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	12%	Ba	11% - 13%	Ba
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	7%	Ba	7% - 9%	Ba
e) Debt/Capitalization (3 Year Avg) (7.5%)	53%	Baa	48% - 50%	Ba
Rating:				
a) Indicated Baseline Credit Assessment from Methodology Grid		A3		A3
b) Actual Baseline Credit Assessment Assigned				A3

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] Last twelve months ended June 30, 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.

MOODY'S INVESTORS SERVICE

MOODY'S
INVESTORS SERVICE

Credit Opinion: FortisBC Energy (Vancouver Island) Inc.

Global Credit Research - 04 Oct 2012

Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Parent: FortisBC Holdings Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa2
Parent: FortisBC Energy Inc.	
Outlook	Stable
Senior Secured -Dom Curr	A1
Senior Unsecured -Dom Curr	A3

Contacts

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Key Indicators

[1]**FortisBC Energy (Vancouver Island) Inc.**

	[2]LTM	2011	2010	2009	2008
(CFO Pre-W/C + Interest) / Interest Expense	4.2x	4.2x	4.5x	4.0x	4.0x
(CFO Pre-W/C) / Debt	19.7%	16.5%	14.7%	13.3%	15.5%
(CFO Pre-W/C - Dividends) / Debt	19.7%	11.8%	9.6%	8.7%	11.8%
Debt / Book Capitalization	44.6%	57.4%	63.3%	60.7%	66.4%

[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] Last twelve months ended June 30, 2012 reflect changes to US-GAAP whereas prior years are reported under Canadian GAAP. Goodwill is included on FEVI's balance sheet with the most notable impact on Debt/Book Capitalization ratios

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

- Low risk, regulated gas local distribution company operating in supportive regulatory environment

- Termination of royalty payments at the end of 2011 puts pressure on financial ratios and competitiveness

- Common rates and amalgamation with FortisBC Energy would facilitate competitiveness in the long term

- Strong regulatory ring-fencing mechanisms

- Sufficient liquidity

Corporate Profile

FortisBC Energy (Vancouver Island) Inc. (FEVI) is a gas LDC serving approximately 100,000 customers on Vancouver Island and the Sunshine Coast in the province of British Columbia (BC). FEVI, which has no unregulated operations, is regulated on a cost of service basis by the British Columbia Utilities Commission (BCUC). FEVI, with a forecasted 2013 rate base of approximately $808 million, is one of the smallest gas utilities rated by Moody's.

FEVI is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI), a holding company which also owns 100% of FortisBC Energy Inc. (FEI, A3 senior unsecured) and FortisBC Energy (Whistler) Inc. (FEW, unrated). FHI has been a wholly-owned subsidiary of Fortis Inc. (FTS, unrated) since May 17, 2007.

SUMMARY RATING RATIONALE

FEVI's A3 senior unsecured rating and stable outlook reflect FEVI's status as a regulated gas LDC operating in a generally supportive regulatory environment. However, FEVI's high cost of service and small size cause its market position to be weaker than that of most gas LDCs. In addition, FEVI's credit metrics are slightly weaker than those of its international peers, albeit stronger than many of its Canadian peers. The rating also reflects FEVI's declining cash flow and financial metrics, from 2013 onwards, due to the phase-out of royalty revenues from the Province at the end of 2011. The impact is not noticeable in the LTM metrics above as FEVI anticipated the event and established a deferred revenue account that it will draw on to smooth the impact of lost revenue payments. We believe the weakness in FEVI's metrics will be temporary as the company will either amalgamate with sister gas LDC, FEI, or increase its rates to offset the cessation of the royalty revenue. We expect the BCUC's decision on FEVI's amalgamation application early in 2013. While an increase in FEVI's rates would be positive for cash flow and corresponding financial metrics, it would reduce the relative competitiveness of gas versus electricity in FEVI's service territory.

FEVI's A3 rating is consistent with the A3 rating implied by Moody's Regulated Electric and Gas Utilities Rating Methodology.

DETAILED RATING CONSIDERATIONS

LOW-RISK REGULATED GAS DISTRIBUTION UTILITY OPERATING IN A SUPPORTIVE REGULATORY ENVIRONMENT

We consider the regulatory environment in BC to be generally supportive since regulatory proceedings tend to be less adversarial and decisions tend to be timely and balanced. The supportiveness of the BC regulatory environment is demonstrated by the fact that FEVI benefits from the existence of a number of BCUC-approved deferral, or true up, mechanisms. These mechanisms limit FEVI's exposure to forecast error with respect to commodity price and volume, pension funding costs, insurance costs and short-term interest rates.

FEVI benefits from a number of regulatory mechanisms that were designed to ensure that its gas rates are roughly cost competitive with electricity and fuel oil. FEVI's high capital costs per customer reflect the significant investment in transmission infrastructure required to reach its relatively small customer base on the Sunshine Coast and Vancouver Island and its lower market penetration relative to other gas LDCs, including FEI.

FEVI's rates have historically been capped such that the cost of gas has been similar to the cost of alternative forms of energy. The Province has subsidized consumers' gas costs by providing FEVI with royalty payments under the Vancouver Island Natural Gas Pipeline Agreement (VINGPA) that expired at the end of 2011. Both the Province and the Federal Government supported the infrastructure build by providing FEVI with non-interest bearing loans.

TERMINATION OF ROYALTY PAYMENTS PUTS PRESSURE ON FINANCIAL RATIOS

The provincial royalty revenues (approximately $15 million in 2011) were terminated at the end of 2011. Anticipating the termination date, FEVI has been able to grow the deferred revenue account since 2009 that it will amortize to smooth the impact of lost revenue payments and provide rate stability. The accumulated revenue surplus is expected to continue to grow this year and exceed $75 million by the end of 2012. While the amortization of this regulatory liability will allow FEVI to earn its allowed ROE on an accrual accounting basis, it does not offset the loss of royalty revenue cash flows. Accordingly, we expect FEVI's cash flow and financial metrics to weaken materially beginning in 2013.

In the absence of amalgamation and rate harmonization, discussed below, once the accumulated revenue surplus has been fully amortized, FEVI will need to increase rates significantly in order to cover its costs of service. While this would allow FEVI to earn its allowed return on equity and would strengthen its cash flow, it would reduce the relative competitiveness of gas versus other forms of energy, principally electricity, in FEVI's service territory.

We note that the provincial government's directive to the BCUC in May of 2012 to reduce the initially proposed rate increase to a cumulative 17% for British Columbia Hydro and Power Authority (BCH, Aaa) over three years associated with a significant increase in deferral accounts to approximately $5BN by 2014 places pressure on FEVI rates to stay competitive.

Similarly, while we currently anticipate that gas prices will remain relatively low for the foreseeable future, we are cognizant of the historical volatility of gas prices and the fact that current prices are low relative to those that prevailed during much of the preceding decade. Accordingly, there is a risk that significant increases in FEVI's delivery rates combined with higher gas commodity costs could cause gas to be uncompetitive with electricity which could lead to a cycle of demand destruction and further gas rate increases.

COMMON RATES AND AMALGAMATION WITH FEI WOULD FACILITATE COST COMPETITIVENESS IN THE LONG TERM

In April of 2012 , FEI, FEVI and FEW filed a Common Rates, Amalgamation and Rate Design Application, which, in addition to the BCUC's consent, would also require the approval of the provincial government. We expect a decision to be made in early 2013.

While Provincial support of amalgamation/rate harmonization is not assured, the Province has long provided financial and regulatory support to FEVI in order to promote its policy goal of ensuring availability of gas on Vancouver Island and we do not expect that to change. We also note that there is a precedent for such a transaction within the Fortis group of companies: in November 2006, Terasen Gas (Squamish) Inc. was amalgamated with FEI and the rates of the two entities were harmonized. While FEVI is considerably larger than Terasen Gas (Squamish) Inc., we believe the Squamish transaction is a positive precedent.

STRONG REGULATORY RING-FENCING SEPARATES FEVI FROM PARENT COMPANIES

FEVI is subject to a set of regulatory ring-fencing conditions imposed by the BCUC. The ring-fencing conditions provide that, unless otherwise approved by the BCUC, FEVI shall: maintain a ratio of common equity to total capital at least as high as the deemed equity capitalization utilized by the BCUC for ratemaking purposes (currently 40%); not pay dividends if they would cause FEVI's common equity to total capital to fall below the BCUC's deemed equity percentage; not invest in or financially support a non-regulated business; and not engage in affiliate transactions on anything other than an arm's length basis. We believe that the BCUC ring-fencing provisions effectively insulate FEVI from the financial and business risks of its parents, FHI and FTS. The regulatory ring-fencing provisions combined with FTS' philosophy of requiring its utility operating subsidiaries to be operationally and financially independent of FTS and other subsidiaries, allows us to evaluate FEVI's credit profile on a stand-alone basis.

Liquidity Profile

We consider FEVI's liquidity resources to be good at the end of Q2 2012.

FEVI is expected to generate approximately $70 million of CFO pre-WC during the 12 months ending June 30, 2013. After dividends in the range of $25 million and capital expenditures and working capital changes of about $50 million, we expect FEVI to be free cash flow negative by approximately $5 million.

With $185 million available under its $200 million syndicated committed revolving credit facility FEVI has enough liquidity to fund this free cash flow shortfall.

The $200 million credit agreement, due to expire in December 2013, contains a single maintenance covenant (debt to equity not greater than 70%). As at December 2011, FEVI's leverage was 57.4% leaving reasonable headroom under the covenant. FEVI's credit agreement does not contain language such as a Material Adverse Change (MAC) clause or ratings triggers that would inhibit access to the unutilized portion of the facility in situations of financial stress.

Rating Outlook

The stable outlook reflects our expectation that the anticipated weakness in FEVI's cash flow and financial ratios will be short-lived. We continue to believe that if a cycle of demand destruction and rate increases were to arise, amalgamation of FEVI, FEI and FEW and the harmonization of rates across the various service territories would be the logical outcome.

What Could Change the Rating - Up

An upgrade to A2 would require a combination of materially stronger metrics and improved competitiveness. We would expect to see CFO pre-WC Interest Coverage in excess of 4.5x; CFO pre-WC/Debt approaching 20% and Retained Cash Flow (RCF)/Debt in the low teens on a sustainable basis. This would require significant increases in FEVI's deemed equity and allowed ROE.

What Could Change the Rating - Down

A downgrade to Baa1 would likely be caused by changes in political and/or regulatory policy that would cause a weakening of FEVI's financial metrics. For instance, CFO pre-WC Interest Coverage in the low 3x range; CFO pre-WC/Debt in the low teens and RCF/Debt in the mid single digit range on a sustained basis.

Rating Factors

FortisBC Energy (Vancouver Island) Inc.

Regulated Electric and Gas Utilities Industry [1]	[2]**Current**		[3]**Moody's 12-18 month Forward View September 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 (10%)		Baa		Baa
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%)	4.3x	Baa	3.5x-4x	Baa
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	17%	Baa	13%-16%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	13%	Baa	9%-12%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	54%	Baa	50%-52%	Baa
Rating:				
a) Indicated Baseline Credit Assessment from Methodology Grid		A3		A3
b) Actual Baseline Credit Assessment Assigned				A3

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] Last twelve months ended June 30, 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.

Rating Report

Report Date:
February 29, 2012

Previous Report
September 19, 2011

Insight beyond the rating.

FortisBC Energy Inc.

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The Company

FortisBC Energy Inc. (FEI or the Company) is the largest natural gas distributor in British Columbia, serving approximately 852,000 customers (December 2011) and representing approximately 90% of the province's natural gas users. The Company is 100% owned by FortisBC Holdings Inc. (FHI, rated BBB (high)), which is a wholly-owned subsidiary of Fortis Inc.

Commercial Paper Limit

$500 million

Recent Actions

September 16, 2011
Confirmed

March 1, 2011
Name Change

Rating

Debt	Rating	Rating Action	Trend
MTNs & Unsecured Debentures	A	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

DBRS has confirmed the Medium-Term Notes (MTNs) & Unsecured Debentures (Debentures) and secured Purchase Money Mortgages (PMMs) ratings of FortisBC Energy Inc. (FEI or the Company) at "A", and its Commercial Paper rating at R-1 (low). The trends are Stable. The MTNs and Debentures have the same rating as the PMMs based on the following: (1) the outstanding amount of the PMMs is not significant (17% of the total); and (2) DBRS does not expect FEI to issue additional PMMs in the future. The rating confirmation reflects FEI's low-risk business with predominantly regulated operations in an economically strong area, a solid financial profile and a reasonable regulatory environment.

FEI's low-risk business is underpinned by its regulated gas transmission and distribution operations (virtually all of FEI's earnings) and sizable customer base (852,000 or 90% of the province's natural gas users). Competition in the Company's franchise area remains limited to electricity, with FEI retaining a competitive operating cost advantage reflecting the current low natural gas price environment. The regulatory framework in British Columbia is viewed as reasonable in terms of cost recovery, returns on equity (ROE of 9.5%) and capital structure (40%). Although FEI's ROE and capital structure could be affected in 2013 due to a regulatory review (see Regulation), DBRS does not expect the outcome of the regulatory review to have a material impact on the Company's earnings and cash flow.

The Company's financial profile remained relatively stable in 2011, with solid debt-to-capital and interest coverage metrics. This was supported by stronger cash flow and the $125 million equity issuance in 2010 (due to a 5% increase in deemed equity). The cash flow-to-debt metric, despite being slightly weaker than DBRS's "A" rating guidelines, has consistently improved since 2007. FEI is expected to generate negative free cash flow in 2012 as a result of capital spending ($195 million in 2012), which is mainly due to its Customer Care Enhancement Project (CCE). DBRS expects FEI to continue to finance the deficits by managing its dividend payouts and equity issuances to the parent, as well as debt issuances, and maintaining its debt-to-capital ratio in line with the current rating. In the absence of an adverse regulatory decision on its ROE and capital structure, beyond what DBRS has expected, FEI's credit metrics are expected to remain relatively stable, supported by higher earnings and cash flow.

Rating Considerations

Strengths
(1) Low business risk and reasonable regulation
(2) Economically strong service territory
(3) Stable and solid financial profile
(4) A large customer base

Challenges
(1) Volume risk
(2) No access to the equity market
(3) Potential change in ROE and deemed equity
(4) Competition from electricity

Financial Information

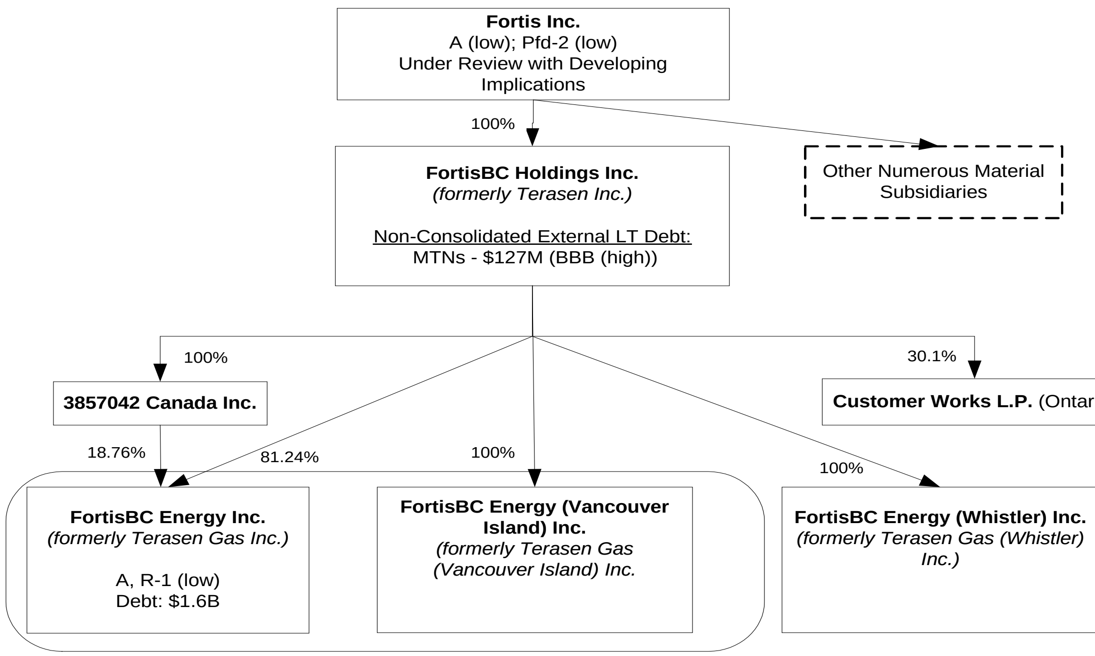
FortisBC Energy Inc. (FEI)	For the year ended December 31st					
	2011	2010	2009	2008	2007	2006
EBIT gross interest coverage (1)	2.21	2.20	2.00	1.97	2.04	2.10
% debt in capital structure (1)	62.0%	62.6%	66.4%	66.4%	66.5%	64.7%
Cash flow/Total debt (1)	11.2%	10.3%	9.8%	9.6%	8.4%	9.7%
Cash flow/Capex	1.13	1.13	1.22	1.35	1.35	1.47
Net income before extra. items (C$ millions)	102	93	87	92	73	68
Cash flow from operations (C$ millions)	191	177	170	166	146	160

(1) Adjusted for operating leases.

FortisBC Energy Inc.

Report Date:
February 29, 2012

Simplified Organization Chart



Potential Amalgamation

FortisBC Energy Inc, FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc. filed an application in the fall of 2011 to amalgamate the three utility subsidiaries under FortisBC Holdings Inc. (FHI, rated BBB (high)). The application was temporarily suspended in late 2011. At this time, DBRS believes the potential amalgamation and associated rate harmonization will likely be credit neutral to FEI, provided that there are no material changes that will negatively affect its rate base and/or its current business model or ROE and capital structure.

Rating Considerations Details

Strengths

(1) **Low business risk**: FEI's operations are predominantly regulated, as most of its earnings are generated from the natural gas transmission and distribution businesses. The competition is limited to other forms of energy (electricity). The regulatory framework in British Columbia is reasonable with respect to cost recovery and returns on investment. FEI is not exposed to commodity costs as natural gas costs are passed on to the customers, with quarterly adjustments.

(2) **Economically strong franchise:** FEI operates in an economically strong service area that includes the City of Vancouver. The customer mix is weighted toward residential and commercial customers (roughly 90% of distribution revenues, 54% of throughput), whose consumption is less sensitive to economic conditions.

(3) **Solid credit metrics:** FEI has maintained its capital structure in line with the regulatory structure (required by the regulator). The current debt-to-capital level of 60% and EBIT interest coverage of 2.2 times (x) are commensurate with its current rating range. DBRS notes that FEI's cash flow-to-debt ratio was slightly weaker than the "A" rating guidelines. However, this ratio has improved consistently since 2007.

(4) **A large customer base:** FEI had a large customer base of approximately 852,000 at the end of 2011. This represented approximately 90% of natural gas users in the province. The large customer base allows the Company to operate more efficiently and carry on large capital projects that are not feasible for utilities with a smaller customer base.

Challenges

(1) V**olume risk:** The Company is exposed to volume risk on industrial and transportation customers, who accounted for approximately 46% of the Company's total throughput in 2011 (over 5% of revenue). These customers' usage is sensitive to economic conditions (such as the pulp and paper industries).

(2) **No direct access to the public equity market:** FEI has no direct access to the public equity market. As a result, it finances cash flow deficits by managing its dividend payouts to the parent and through equity issuances to the parent, as well as other debt issuances. When deemed equity changed in 2010, increasing from 35% to 40%, the Company issued $125 million in equity to the parent to maintain its capital structure in line with the regulator's requirement. The company's current rating incorporates DBRS's expectation that the parent will continue to provide financing support in the future if required.

(3) **Generic Cost of Capital Proceeding (GCCP):** The British Columbia Utilities Commission (BCUC) is initiating a GCCP, in which it will review setting the cost of capital for a benchmark low-risk utility (such as FEI) and establishing a return on equity automatic adjustment mechanism. This could have a material impact on FEI's ROE and deemed equity.

(4) **Competitive environment:** Natural gas distribution operators in British Columbia face more intense competition from electricity than other provinces in Canada (except Québec) due to low power costs in the province. However, FEI currently benefits from a low gas price environment, which is expected to remain low for the foreseeable future.

Regulation

Overview: DBRS views the regulatory framework in British Columbia as reasonable, as it allows FEI to earn a reasonable return on its capital investment and to recover prudently incurred operating costs. In addition, the Company does not have exposure to gas price risk since costs are generally passed through to the customers, subject to a reasonable regulatory lag. FEI is regulated by the BCUC.

- The BCUC uses a future test year to establish rates for a utility. FEI forecasts the volume of gas to be sold, gas supply costs and all operating costs that are incurred in the test year.
- Based on the forecast, the BCUC will set rates to permit FEI to collect all of its forecast costs.
- FEI has a number of deferral accounts that are used to ameliorate unanticipated changes in certain forecast items, including the following two:

(1) Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA):
- Any differences between actual and forecast gas costs are captured and recorded in these deferral accounts to be recovered or refunded in future rates.
- Forecast gas prices are adjusted on a quarterly basis, mitigating the impact of the recovery lag.

(2) Revenue Stabilization Adjustment Mechanism (RSAM):
- The RSAM seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in forecast versus actual customer usage throughout the year to recover them in rates over the following three years. This reduces FEI's earnings volatility.
- Volume variances from large-volume industrial transportation and sales customers, which account for approximately 45% of FEI's total throughput, are not included in this deferral account. However, these customers' usage is more predictable and less likely to be significantly affected by weather, even though it is sensitive to economic conditions.

Rate Design
- Prior to 2010, FEI operated under a performance-based rate plan (PBR).
- In 2010 and 2011, FEI operated under a Negotiated Settlement Agreement (NSA), during which time the Company's ROE and deemed equity were at 9.50% and 40%, respectively.
- Variances in certain operating expenses, including property taxes and changes in tax rates are deferred until the next rate application.
- The Company may apply from time to time for rate changes should it incur costs that are beyond its control.
- The current ROE and the capital structure are expected to remain the same until amended by the BCUC.
- In late 2011, the BCUC notified FEI that it plans to initiate a GCCP in 2012. This proceeding may result in a change in ROE and capital structure for FEI.
- In 2011, FEI filed an application for its 2012-2013 revenue requirements and delivery rates (2012-2013 RRA). The application forecast an average rate base of $2,760 million for 2012 and $2,820 million for 2013. The forecast for a higher rate base reflects significant capital projects related to system integrity and reliability.
- The 2012-2013 RRA seeks a 3% increase in burn-tip rates for 2012 and a 3.1% increase for 2013.
- Rates, including interim delivery and midstream rates, for FEI residential customers increased by 3% effective January 2012 (compared to the preceding quarter) for Lower Mainland, Frazer Valley, Interior, North and the Kootenays, which included the 2012-2013 RRA request on the interim basis.

Regulatory Ring-Fencing
- The regulatory ring-fencing imposed on FEI by the BCUC at the time Fortis Inc. acquired FEI in 2007 (a continuation of the ring-fencing imposed upon acquisition of the former Terasen Inc. by Kinder Morgan Inc. in December 2005) is intended to ensure that public interest is protected and that FEI will continue to operate as a separate, stand-alone entity without undue parental influence.
- One of these conditions is that FEI must maintain its debt-to-capital ratio in line with the regulatory capital structure.

Earnings and Outlook

Consolidated Income Statement: FEI	For the year ended December 31st					
(C$ millions)	**2011**	**2010**	**2009**	**2008**	**2007**	**2006**
EBITDA	323	317	297	292	293	301
EBIT	233	226	214	214	215	217
Gross interest expense	108	104	109	111	108	106
Pre-tax income	129	123	106	103	108	112
Income tax	27	30	19	12	35	44
Net income before extra. items	102	93	87	92	73	68
Reported net income	102	93	87	92	78	68
Return on avg. common equity	9.8%	9.8%	9.9%	10.4%	8.2%	7.8%
Rate Base	2,634	2,540	2,547	2,510	2,484	2,516
Approved common equity	40.0%	40.0%	35.0%	35.0%	35.0%	35.0%
Allowed ROE	9.50%	9.50%	8.99%	8.62%	8.37%	8.80%

Summary

- Earnings in 2011 continued to benefit from the 2009 ROE and capital structure decision, which established higher ROE and deemed equity for 2010 and 2011, compared with previous years.
- Higher transportation volumes to the forestry and mining sectors also contributed to higher earnings in 2011. Although the forestry sector has stabilized recently, it remains very sensitive to economic conditions.
- Volume usage volatility as a result of changes in weather conditions is mitigated by the RSAM, which allows FEI to defer variances due to changes in usage rates, to be recovered/refunded over the subsequent three years.

Outlook

- The Company's 2012 earnings are expected to increase modestly as the rate base continues to grow, reflecting ongoing capital expenditures.
- The BCUC is initiating the GCCP in 2012, which could have a negative impact on FEI's earnings; however, DBRS does not expect the outcome of this regulatory review to have a material impact on the Company's earnings.

FortisBC Energy Inc.

Report Date:
February 29, 2012

Financial Profile

Consolidated Cash Flow Statement: FEI	For the year ended December 31st					
(C$ millions)	**2011**	**2010**	**2009**	**2008**	**2007**	**2006**
Net income before extra. items	102	93	87	92	73	68
Depreciation & amortization	89	91	83	78	79	84
Deferred income taxes/Other	(1)	(7)	0	(4)	(5)	8
Cash flow from operations	191	177	170	166	146	160
Dividends paid	(85)	(84)	(67)	(100)	(111)	(40)
Capex	(169)	(157)	(139)	(123)	(108)	(109)
Free cash flow before WC	(63)	(64)	(36)	(57)	(73)	11
Changes in working capital (WC)	95	(15)	16	33	(28)	83
Net free cash flow	32	(79)	(20)	(24)	(101)	95
Acquisitions	0	0	0	0	0	0
Assets sales/Divestitures	0	0	0	14	0	0
Net changes in equity	0	125	0	0	0	0
Net changes in debt	(12)	(24)	6	(5)	89	(98)
Other/Adjustments by DBRS	(17)	(13)	7	22	11	(7)
Change in cash	2	9	(7)	7	(1)	(9)
(C$ millions)						
EBITDA ($ millions)	323	317	297	292	293	301
Total debt ($ millions)(1)	1,709	1,712	1,737	1,733	1,740	1,652
Total debt in capital structure	60.5%	61.3%	65.2%	65.2%	65.2%	63.4%
Total debt in capital structure (1)	62.0%	62.6%	66.4%	66.4%	66.5%	64.7%
Cash flow/Total debt (1)	11.2%	10.3%	9.8%	9.6%	8.4%	9.7%
EBIT gross interest coverage (1)	2.21	2.20	2.00	1.97	2.04	2.10
Total debt/EBITDA (1)	5.30	5.41	5.85	5.94	5.94	5.49
Capex/Depreciation	1.89	1.72	1.68	1.57	1.38	1.30
Dividend payout ratio	83.4%	90.1%	76.8%	109.3%	152.1%	58.5%

(1) Adjusted for operating leases.

Summary

- Cash flow from operations has increased steadily since 2007, reflecting the Company’s growing rate base.
- Capital investments to support load growth and system reliability have also increased considerably over this period. This, combined with high dividend payouts (an average of 85% over the last four years), has resulted in cash flow deficits (before working capital).
- DBRS notes that a large swing in working capital in 2011 was a result of changes in deferred accounts.
- The Company continued to manage its dividend payouts and equity issuances so that its capital structure is in line with the conditions imposed by the BCUC, which stipulates that FEI must maintain its capital structure in line with the regulatory structure.
- When the deemed equity was raised to 40% in 2010 from 35% in 2009, the Company issued $125 million in equity to its parent to finance cash flow deficits and to comply with the 40% equity structure.
- As a result, FEI’s credit metrics improved moderately in 2010 and remained stable in 2011.
- Despite the improvement, the cash flow-to-debt ratio remained slightly weaker than the “A” rating range. However, the other two key credit metrics (debt-to-capital ratio and EBIT interest coverage) were commensurate with the current rating.

Outlook

- Cash flow deficits are expected to continue as capital expenditures are expected to remain high at $195 million for 2012 (estimate) largely due to the CCE Project. DBRS expects the Company to continue to finance its capital expenditures by managing dividends and equity issuances to the parent as well as other debt issuances and maintaining its capital structure in line with its current rating range.
- In the absence of any adverse regulatory decisions affecting ROE or capital structure, DBRS expects FEI's credit metrics to remain relatively stable in 2012.

Long-Term Debt and Liquidity

Liquidity

Facilities	Committed	Drawn/LC	Available	Expiry
(C$ millions)				
Syndicated unsecured credit facility	500	113.2	386.8	Aug-13

- The credit facility is primarily used to support FEI's $500 million commercial paper (CP) program.
- Due to the seasonal nature of the business, liquidity requirements peak in the fall and winter. DBRS views FEI's liquidity as sufficient for its funding requirements during the peak period.

Debt Maturity Schedule

Debt Maturities	2012	2013	2014	2015	2016	Thereafter	Total
(C$ millions)							
Long-term	2.9	2.9	2.9	77.8	202.9	1,256.0	1,545.4
Short-term	65.0						65.0
Total	67.9	2.9	2.9	77.8	202.9	1,256.0	1,610.4
% of total	4%	0%	0%	5%	13%	78%	100%

- The Company's near-term refinancing risk remains modest, as the debt maturity schedule is light until 2016 when over $200 million (or 13%) of total debt will be due.
- DBRS believes that refinancing of the debt maturity is manageable, given the Company's strong credit profile.

Debt Instruments

Debt Instruments	2011	2010
(C$ millions)		
Credit facilities	65	178
Secured Purchase Money Mortgages	275	275
Unsecured Debentures and MTNs	1,270	1,173
Capital leases	15	13
Total	1,624	1,639
Less: Current portion and LT issue costs	(14)	(16)
Total	1,610	1,623

- MTNs and Unsecured Debentures have the same rating as PMMs based on the following: (1) the outstanding amount of the PMMs is not significant (only 17% of the total); and (2) DBRS does not expect FEI to issue new PMMs in the future.
- The bank facility is unsecured but ranks equally with the Company's secured debt.
- In December 2011, FEI issued $100 million of unsecured MTNs, maturing in 2041. The net proceeds were used to repay a credit facility and for general corporate purposes.

FortisBC Energy Inc.

Report Date:
February 29, 2012

FortisBC Energy Inc.

Balance Sheet (C$ millions)	**Dec. 31**	**Dec. 31**	**Dec. 31**		**Dec. 31**	**Dec. 31**	**Dec. 31**
Assets	**2011**	**2010**	**2009**	**Liabilities & Equity**	**2011**	**2010**	**2009**
Cash & equivalents	17	15	6	S.T. borrowings	65	178	204
Accounts receivable	238	298	277	Current portion L.T.D.	3	3	2
Inventories	101	136	149	Accounts payable	304	358	337
Others	82	108	92	Deferred tax	0	1	8
				Others	58	51	45
Total Current Assets	**439**	**557**	**524**	**Total Current Liabilities**	**430**	**591**	**597**
Net fixed assets	2,513	2,466	2,423	Long-term debt (L.T.D.)	1,543	1,442	1,440
Future income tax assets	0	0	0	Deferred income taxes	304	280	271
Goodwill & intangibles	117	95	83	Other L.T. liabilities	177	149	181
Investments & others	435	366	340	Shareholders equity	1,050	1,023	881
Total Assets	**3,503**	**3,484**	**3,370**	**Total Liab. & SE**	**3,503**	**3,484**	**3,370**

Balance Sheet &	For the year ended December 31st					
Liquidity & Capital Ratios	**2011**	**2010**	**2009**	**2008**	**2007**	**2006**
Current ratio	1.02	0.94	0.88	0.80	0.65	0.65
Net debt in capital structure	60.3%	61.1%	65.1%	65.0%	65.1%	63.3%
Total debt in capital structure	60.5%	61.3%	65.2%	65.2%	65.2%	63.4%
Total debt in capital structure (1)	62.0%	62.6%	66.4%	66.4%	66.5%	64.7%
Cash flow/Net debt	12.0%	11.0%	10.3%	10.2%	8.9%	10.3%
Cash flow/Total debt	11.8%	10.9%	10.3%	10.1%	8.9%	10.3%
Cash flow/Total debt (1)	11.2%	10.3%	9.8%	9.6%	8.4%	9.7%
Cash flow/Capex	1.13	1.13	1.22	1.35	1.35	1.47
(Cash flow - Dividends)/Capex	0.62	0.59	0.74	0.54	0.33	1.11
Deemed common equity	40.0%	40.0%	35.0%	35.0%	35.0%	35.0%
Dividend payout ratio	83.4%	90.1%	76.8%	109.3%	152.1%	58.5%
Coverage Ratios (times)						
EBIT gross interest coverage	2.17	2.17	1.96	1.92	1.99	2.05
EBITDA gross interest coverage	3.00	3.04	2.72	2.62	2.72	2.84
Fixed-charges coverage	2.17	2.17	1.96	1.92	1.99	2.05
Debt/EBITDA	4.99	5.13	5.55	5.62	5.62	5.18
EBIT gross interest coverage (1)	2.21	2.20	2.00	1.97	2.04	2.10
Profitability Ratios						
EBITDA margin	23.8%	23.2%	20.7%	17.5%	19.2%	19.7%
EBIT margin	17.2%	16.6%	14.9%	12.8%	14.1%	14.2%
Profit margin	7.5%	6.8%	6.0%	5.5%	4.8%	4.5%
Return on equity	9.8%	9.8%	9.9%	10.4%	8.2%	7.8%
Return on capital	6.5%	6.2%	6.2%	6.4%	5.5%	5.1%
Allowed ROE	9.5%	9.5%	9.0%	8.6%	8.4%	8.8%

(1) Adjusted for operating leases.

FortisBC Energy Inc.

Report Date:
February 29, 2012

Ratings

Debt	Rating	Rating Action	Trend
MTNs & Unsecured Debentures	A	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating History

Debt Rated	Current	2011	2010	2009	2008	2007
MTNs & Unsecured Debentures	A	A	A	A	A	A
Purchase Money Mortgages	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Related Research

- FortisBC Holdings Inc., Rating Report, February 29, 2012.

Notes:
All figures are in Canadian dollars unless otherwise noted.

MOODY'S
INVESTORS SERVICE

Credit Opinion: FortisBC Energy Inc.

Global Credit Research - 26 Jun 2013

Vancouver, British Columbia, Canada

Ratings

Category	**Moody's Rating**
Outlook	Negative
Senior Secured -Dom Curr	A1
Senior Unsecured -Dom Curr	A3
Parent: FortisBC Holdings Inc.	
Outlook	Negative
Senior Unsecured -Dom Curr	Baa2
FortisBC Energy (Vancouver Island) Inc.	
Outlook	Negative
Senior Unsecured -Dom Curr	A3

Contacts

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Key Indicators

[1]**FortisBC Energy Inc.**

	2012	[2]**2011**	**2010**	**2009**
(CFO Pre-W/C + Interest) / Interest Expense	**2.4x**	**2.2x**	**2.7x**	**2.6x**
(CFO Pre-W/C) / Debt	**14.1%**	**11.2%**	**10.6%**	**10.2%**
(CFO Pre-W/C - Dividends) / Debt	**9.2%**	**6.5%**	**5.9%**	**6.5%**
Debt / Book Capitalization	**45.3%**	**47.4%**	**59.1%**	**61.8%**
Source: Moody's Financial Metrics TM				

[1] All ratios are calculated using Moody's Standard Adjustments. [2] 2011 Key Indicators reflect the company's retrospective changes due to adoption of US GAAP, effective January 1, 2012

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low business risk utility in a supportive regulatory environment

Weak financial metrics are expected to decline further

Adequate liquidity and manageable capex

Corporate Profile

FortisBC Energy Inc. (FEI) is the largest distributor of natural gas in British Columbia and one of the largest gas local distribution companies (LDC) in Canada. FEI is regulated on a cost-of-service basis by the British Columbia Utilities Commission (BCUC).

FEI is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI; Baa2 negative) which, in turn, is a wholly-owned subsidiary of Fortis Inc. (FTS, not rated), a diversified electric and gas utility holding company, headquarted in St. John's, NL. FHI also owns 100% of FortisBC Energy (Vancouver Island) Inc. (FEVI; A3 negative) and FortisBC Energy (Whistler) Inc. (FEW, not rated).

SUMMARY RATING RATIONALE

FEI's A3 senior unsecured rating reflects its low-risk LDC business model and the generally supportive regulatory environment in British Columbia. As an LDC, FEI is able to produce stable and predictable cash flow from operations, which are supported by the regulated revenues approved by the BCUC and its cost of service ratemaking model. FEI's rating reflects a relatively high use of leverage, and the historically weak financial metrics for an A3 utility, especially when compared to US peers that typically earn higher returns on a more equity rich capital structure. The BCUC's recent generic cost of capital decision (GCOC), which reduced both FEI's allowed ROE level and equity component for rates, is likely to weaken the company's financial metrics further and is the impetus for the company's negative ratings outlook.

DETAILED RATING CONSIDERATIONS

LOW RISK OPERATIONS IN A SUPPORTIVE REGULATORY ENVIRONMENT

FEI's investment grade rating is primarily supported by the revenue and cost recovery certainty provided by a regulated business model and monopoly service territory. The BCUC offers a cost of service based regulatory compact, which allows FEI to generate a predictable amount of cash flow, supporting its relatively modest capital program for a stable residential customer base.

We view the BC regulatory framework to be similar in its framework to a strong US jurisdiction, due to similar procedural and legal processes and supportive cost recovery features, including a forward looking test year, deferral accounting for certain costs and timely decisions from the commission. The deferral, or true-up, mechanisms limit FEI's exposure to forecast error are in respect to commodity price and volume, pension funding costs, insurance costs and short-term interest rates. In addition, FEI is required to obtain a certificate of public convenience and necessity (CPCN) from the BCUC prior to undertaking any capital project in excess of $5 million. In our view, this process reduces the risk that FEI would be denied the opportunity to recover the cost of its capital investments. This is also similar to US processes, which include CPCNs and integrated resource plans.

The primary areas where Canadian regulation is viewed as less credit supportive than other jurisdictions, includes the lower allowed ROE levels and lower equity component of the rate structure. In general, the US maintains 10% (or slightly below) allowed ROEs for integrated, transmission and distribution (T&D) and LDC companies, with capital structures that approximate a 50/50 balance of debt and equity. Furthermore, most states in the US have trended toward implementing various riders or trackers that allow utilities to automatically recover certain costs (e.g., environmental capex, lost margin due to efficiencies or customer conservation, infrastructure replacement, etc.) on a timely basis (most are annual true-ups) and in between general rate case proceedings. The FortisBC utilities do not benefit from many of these interim recovery features, though future test years can often obviate the need for some of these mechanisms and FEI does have annual true-ups for efficiency (rate stabilization accounts) that occur outside of the rate setting process, a credit positive.

WEAK FINANCIALS VERSUS US PEERS

FEI's cash flow to debt metrics have been steadily increasing since 2009, with CFO pre-WC to debt growing from 10% in 2009 to 14% in 2012. Despite this improvement, the 2010-2012 average CFO pre-WC interest coverage of 2.5x and CFO pre-WC to debt of 12% compares unfavorably to A3 rated LDC companies in the US, which have averaged over 6.0x CFO pre-WC interest coverage and nearly 25% CFO pre-WC to debt, respectively, over the same time horizon. Even the Baa1 US LDC companies have been able to produce over 5.0x and nearly 23% CFO pre-WC to debt from 2010-2012.

BCUC's GENERIC COST OF CAPITAL OUTCOME WILL NEGATIVELY IMPACT FINANCIAL METRICS

In May 2013, the BCUC issued a final order in Stage 1 of its GCOC, which included a reduction of FEI's (the benchmark utility) common equity ratio to 38.5% from 40.0%, and a reduction in allowed ROE of 8.75% from 9.50%. The decision also re-established an automatic adjustment formula (AAM) which considers changes to utility bond spreads and the 30 year Government of Canada bond yields to determine the benchmark ROE on an annual basis, for years 2014 and 2015. Though the AAM could provide automatic lift to allowed ROE's in times of rising interest rates, a credit positive, our expectation is that the impact of the GCOC is likely to reduce future cash flow generation of FEI.

Given the GCOC's downward revision to ROE and equity layer, we expect that FEI's CFO pre-WC to debt will reverse the trajectory seen in recent years and fall below 13% over the intermediate-term. Although this expected financial profile is more in line with more highly levered Canadian peers, the degree of BCUC regulatory support may not be of sufficient strength to support FEI's A3 unsecured rating, while exhibiting cash flow to debt metrics that are borderline investment grade, according to our Regulated Electric and Gas Utilities Rating Methodology.

In June 2013, FEI filed an application seeking approval of a five-year performance based ratemaking plan, which would offer formula-driven spending cap on O&M and capital expenditures, and other components will be reset each year, along with actual rates. The plan, if approved, would be a credit positive; however, the degree of the impact will depend upon what is actually implemented by the BCUC.

DENIED AMALGAMATION OF FEI, FEVI AND FEW HAS NO CREDIT IMPACT FOR FEI

In 2012, FEI, FEVI and FEW filed a joint application with the BCUC to amalgamate and harmonize rates across the. In February 2013, the BCUC issued a decision which denied the application, citing a desire to maintain the status quo, which had previously determined utility rates based on causality (i.e., appropriate rates applied to a given utility based upon its respective and specific needs). The commission noted that the amalgamation would result in significant and unfair cross subsidization of FEVI and FEW customers by the customers of FEI and FortisBC Energy Inc. Fort Nelson Service Area (not rated).

The amalgamation denial is negative to FEVI, whose customers would have benefitted from the subsidization effects. FEVI now faces significant rate increases on the heels of a large capex program and the end of governmental subsidies. The amalgamation denial is credit neutral to FEI, as it will simply maintain its independent rate structure and eliminates the potential for higher rates as a result of the cross subsidization effects.

Liquidity Profile

For LTM 1Q13, FEI produced about $200 million of adjusted CFO compared to $165 million of capital expenditures and $65 million of dividends. We expect a similar amount of free cash flow deficit (approximately $30 million) over the course of 2013, as the company continues with a stable capital plan and upstream dividends with an eye toward maintaining its BCUC allowed capital structure.

FEI's external liquidity is supported by a $500 million facility maturing in August 2014, which supports its $500 million commercial paper program. The company is currently well below the debt to total capitalization ratio covenant (maximum 75%) in the credit agreement. As of March 31, 2013, there was $449 available under the facility.

We recognize that FEI's reliance on short-term debt to finance gas inventories is supported by the BCUC and that the BCUC has approved the use of an interest rate deferral account to limit FEI's exposure to short-term interest rate volatility, specifically on gas inventories. However, we believe that FEI's financial flexibility can become somewhat constrained, particularly when material debt maturities fall within the peak storage season and especially since the BCUC's July 2011 decision to eliminate the majority of FEI's commodity hedging activities. Although we expect a sustained period of low natural gas prices, this philosophical change is viewed negatively from a credit perspective and could increase the volatility of FEI's cash flow and increase its liquidity requirements.

FEI has only small amounts of debt amortization (approximately $7 million) over the near-term and $75 million maturing in September 2015.

Rating Outlook

The negative rating outlook primarily reflects our expectation for FEI's financial profile to decline over the intermediate-term as reduced ROE and equity levels are likely to result in lower cash flow production and negatively impact CFO to debt metrics.

What Could Change the Rating - Up

It is not likely that FEI's rating will experience upward movement over the near-term. However, if BCUC support were to improve and financial metrics of CFO pre-WC interest coverage were to exceed 4.0x and CFO pre-WC to debt were to be above 19% on a sustainable basis, that would have a positive credit impact.

What Could Change the Rating - Down

A determination that the BCUC has become a less supportive and predictable regulatory framework would likely result in a downgrade of FEI's rating, but today, we still view the regulator as supportive to long-term credit quality. The recent reduction in allowed ROE and the equity component in the capitalization is viewed as the regulator exercising its authority over the utility monopoly's profitability, and not as a sign of a more contentiousness environment. Ratings could also fall if sustained CFO pre-WC to debt metrics fall below 12%.

Rating Factors

FortisBC Energy Inc.

Regulated Electric and Gas Utilities [1][2]	**Current 12/31/2012**		[3]**Moody's 12-18 month Forward View As of Date Published**	
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%)		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%)	2.4x	Ba	2.5 - 2.8x	Ba
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	12%	Ba	12.5 -13.5%	Ba
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	7%	Ba	7.5 - 9%	Ba
e) Debt/Capitalization (3 Year Avg) (7.5%)	50%	Baa	46 - 50%	Baa
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		A3		A3

Source: Moody's Financial Metrics TM

[1] All ratios are calculated using Moody's Standard Adjustments. [2] Based on financial data as of 12/31/2012. [3] This represents Moody's forward view; not the view of the issuer.

at www.moodys.com under the heading "Shareholder Relations — Corporate Governance — Director and Shareholder Affiliation Policy."

MOODY'S INVESTORS SERVICE

Credit Opinion: FortisBC Energy (Vancouver Island) Inc.

Global Credit Research - 26 Jun 2013

Canada

Ratings

Category	Moody's Rating
Outlook	Negative
Senior Unsecured -Dom Curr	A3
Parent: FortisBC Holdings Inc.	
Outlook	Negative
Senior Unsecured -Dom Curr	Baa2
Parent: FortisBC Energy Inc.	
Outlook	Negative
Senior Secured -Dom Curr	A1
Senior Unsecured -Dom Curr	A3

Contacts

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Key Indicators

[1]**FortisBC Energy (Vancouver Island) Inc.**

	2012	[2]2011	2010	2009
(CFO Pre-W/C + Interest) / Interest Expense	4.8x	4.4x	4.5x	4.0x
(CFO Pre-W/C) / Debt	19.6%	18.0%	14.8%	13.3%
(CFO Pre-W/C - Dividends) / Debt	17.7%	13.3%	9.7%	8.7%
Debt / Book Capitalization	44.0%	48.4%	63.2%	60.6%

Source: Moody's Financial Metrics TM

[1] All ratios are calculated using Moody's Standard Adjustments. [2] 2011 Key Indicators reflect the company's retrospective changes due to adoption of US GAAP, effective January 1, 2012

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low-risk rate regulated operations

Financial metrics expected to weaken in the near-term

Small size of operations

Inadequate liquidity profile expected to be addressed near-term

Corporate Profile

FortisBC Energy (Vancouver Island) Inc. (FEVI) is a gas LDC serving approximately 102,000 customers on Vancouver Island and the Sunshine Coast in the province of British Columbia (BC). FEVI, which has no unregulated operations, is regulated on a cost of service basis by the British Columbia Utilities Commission (BCUC). FEVI, with a forecasted 2013 rate base of approximately $808 million, is one of the smallest gas utilities rated by Moody's.

FEVI is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI; Baa2 negative), a holding company which also indirectly owns 100% of FortisBC Energy Inc. (FEI, A3 negative) and FortisBC Energy (Whistler) Inc. (FEW; not rated).

SUMMARY RATING RATIONALE

FEVI's A3 rating reflects its status as a regulated gas LDC operating in a generally supportive regulatory environment. FEVI's high cost of service and small size cause its market position to be weaker than that of most gas LDCs and recent developments regarding the phase-out of royalty revenues from the Province and a denied application to amalgamate operations with affiliates FEI and FEW underscores the company's need for additional BCUC support to maintain current financial metrics. The BCUC's recent Stage 1 generic cost of capital decision (GCOC), which reduced the benchmark utility's (i.e., FEI's) allowed ROE level to 8.75% from 9.50% and equity component for rates, will also reduce FEVI's ROE by 75 basis points as it moves down in lock-step with the benchmark; thus, we expect that the company's financial metrics will decline in the near-term, which is the impetus for the company's negative ratings outlook.

DETAILED RATING CONSIDERATIONS

REGULATED COST RECOVERY AND LOW RISK OPERATIONS UNDERPINS RATING

FEVI's investment grade rating is primarily supported by the revenue and cost recovery certainty provided by a regulated business model and monopoly service territory. We view the BC regulatory framework to be similar in its framework to a strong US jurisdiction, due to similar procedural and legal processes and supportive cost recovery features, including a forward looking test year, deferral accounting for certain costs and timely decisions from the commission. Deferral, or true-up, mechanisms limit FEVI's exposure to forecast error with respect to commodity price, pension costs, and insurance costs. In addition, FEVI employs a Rate Stabilization Deferral Account (RSDA) which captures the difference between FEVI's approved and actual costs (with the exception of operating expenses other than pension and insurance) as part of its rate-setting mechanism.

The primary areas where Canadian regulation is viewed as less credit supportive than other jurisdictions, includes the lower allowed ROE levels and lower equity component of the rate structure. In general, the US maintains 10% (or slightly below) allowed ROEs for integrated, transmission and distribution (T&D) and LDC companies, with capital structures that approximate a 50/50 balance of debt and equity. Furthermore, most states in the US have trended toward implementing various riders or trackers that allow utilities to automatically recover certain costs (e.g., environmental capex, lost margin due to increased efficiencies or customer conservation, infrastructure replacement, etc.) on a timely basis (most are annual true-ups) and in between general rate case proceedings. The FortisBC utilities do not benefit from many of these interim recovery features, though future test years can often obviate the need for some of these mechanisms. Furthermore, FEVI does have some annual true-ups for efficiency (rate stabilization accounts) and regulatory reviews of potential expenses (e.g., certificate of public convenience and necessity for certain projects, similar to the process in the US) that further enhance likelihood of cost recovery.

FINANCIAL METRICS EXPECTED TO DECLINE FOLLOWING TERMINATION OF ROYALTY PAYMENTS AND POTENTIAL REDUCTION IN ROE

We expect for FEVI to have declining cash flow and financial metrics, from 2013 onwards, due to the phase-out of royalty revenues from the Province at the end of 2011. The provincial royalty revenues (approximately $15 million in 2011) were part of the Vancouver Island Natural Gas Pipeline Agreement (VINGPA), which was made in an effort to increase and develop the natural gas market for Vancouver Island and the Sunshine Coast. Both the Province and the Federal Government supported the infrastructure build by providing FEVI with non-interest bearing loans; however, this revenue stream was terminated, as expected, at the end of 2011.

Anticipating the termination date, FEVI has been able to grow the RSDA since 2009, allowing the company to amortize and smooth the impact of higher future costs by providing near-term rate stability. While the amortization of this regulatory liability will allow FEVI to earn toward its allowed ROE on an accrual accounting basis, it does not offset the long-term loss of royalty revenue cash flows. Accordingly, we expect FEVI's cash flow and financial metrics to weaken materially beginning in 2013.

We see additional risk to FEVI's production of future cash flow due to the BCUC's recent decision in Stage 1 of the GCOC process. In May 2013, the BCUC issued a final order in Stage 1, which included a reduction of FEI's (the benchmark utility) common equity ratio to 38.5% from 40.0%, and a reduction in allowed ROE of 8.75% from 9.50%. The decision also re-established an automatic adjustment formula (AAM) which considers changes to utility bond spreads and the 30 year Government of Canada bond yields to determine the benchmark ROE on an annual basis, for 2014 and 2015. Though the AAM could provide an automatic lift to allowed ROE's in times of rising interest rates, a credit positive, our expectation is that the impact of the GCOC decisions will negatively impact FEVI `s financial profile as well. For example, FEVI's allowed ROE has decreased to 9.25% (FEVI had a 10% allowed ROE prior to the Stage 1 decision) and the individual risk premium of 50 basis points and the capital structure are currently under review in Stage 2 of the process. This review could lead to a further change in the ROE and equity ratio for FEVI. Given the reduction to FEI's equity layer, we see potential for FEVI's equity layer to be reduced in a similar fashion.

Given the GCOC's downward revision to the benchmark ROE and potential for a reduced equity layer, we expect that FEVI's CFO pre-WC to debt could potentially fall below 13% over the intermediate-term. Although this expected financial profile is more in line with more highly levered Canadian peers (FEVI's historical financials have compared well versus Canadian peers), the degree of BCUC regulatory support may not be of sufficient strength to support FEVI's A3 unsecured rating, while exhibiting cash flow to debt metrics that are borderline investment grade, according to our Regulated Electric and Gas Utilities Rating Methodology.

SMALL SIZE HIGHLIGHTS VULNERABILITY TO EXTERNALITIES

In an effort to combat the negative impact of royalty payments expiring, the FortisBC gas utilities of FEVI, FEI and FEW, filed a joint application with the BCUC to amalgamate and harmonize rates. The impact would have been positive for FEVI customers, as postage stamp rates would lower rates and improve competitiveness in FEVI's service territory relative to alternative energy forms, namely, electricity; however, in February 2013, the BCUC issued a decision which denied the application. The BCUC cited a desire to maintain the status quo, which had previously determined utility rates based on causality (i.e., appropriate rates applied to a given utility based upon its respective and specific needs). The commission noted that the amalgamation would result in significant and unfair cross subsidization of FEVI and FEW customers by the customers of FEI and FortisBC Energy Inc. Fort Nelson Service Area (not rated). The FortisBC gas utilities are currently appealing the decision.

The amalgamation denial is negative to FEVI, whose customers would have benefitted from the lowered rates. FEVI now faces significant rate increases on the heels of a large capex program related to the construction of the Mt. Hayes LNG facility and the end of government subsidies. FEVI's high capital costs per customer reflect the significant investment in transmission infrastructure required to reach its relatively small customer base on the Sunshine Coast and Vancouver Island and its lower market penetration relative to other gas LDCs, including FEI.

FEVI's rates have historically been capped such that the cost of gas has been similar to the cost of alternative forms of energy. Now, with the expiration of royalty payments, the company will likely require significant rate increases to maintain its financial stability. This highlights the need for the small utility, with smaller scale and less ability to spread fixed costs across a larger customer base, to receive regulatory support in the midst of what could be a rate shock environment for FEVI customers.

Liquidity Profile

FEVI's liquidity profile is inadequate, given the December 2013 expiration of its $200 million credit facility. Although we expect the company to extend this facility in the coming months, our strict quantitative consideration of liquidity does not assume refinancing or credit facility extensions over the twelve month horizon. The facility, which had $164 million available as of December 31, 2012, contains a single maintenance covenant (debt to equity not greater than 70%). As at December 2012, FEVI had reasonable headroom under the covenant. FEVI's credit agreement does not contain language such as a Material Adverse Change (MAC) clause or ratings triggers that would inhibit access to the unutilized portion of the facility in situations of financial stress.

FEVI is expected to generate approximately $65 million of CFO pre-WC over the next twelve months, compared to capital expenditures and working capital changes of about $40 million. FEVI's dividend payout was managed to maintain the equity component of rate base in 2012, but we expect FEVI to return to a more robust dividend payout level and for that to translate into a moderately free cash flow negative position over the next twelve months.

FEVI has $23.6 million of long-term maturities due in 2013. The next material maturity is not until 2038.

Rating Outlook

The negative rating outlook primarily reflects our expectation for FEVI's financial profile to decline over the intermediate-term due to reductions in cash flow.

What Could Change the Rating - Up

It is not likely that FEVI's rating will experience upward movement over the near-term. However, if BCUC support were to improve and financial metrics of CFO pre-WC interest coverage were to exceed 4.0x and CFO pre-WC to debt were to be above 19% on a sustainable basis, that would have a positive credit impact.

What Could Change the Rating - Down

A determination that the BCUC has become a less supportive and predictable regulatory framework would likely result in a downgrade of FEVI's rating, but today, we still view the regulator as supportive to long-term credit quality. The recent reduction in the benchmark ROE and the potential for a lower equity component in the capitalization is viewed as the regulator exercising its authority over the utility monopoly's profitability, and not as a sign of a more contentiousness environment. Ratings could also fall if sustained CFO pre-WC to debt metrics fall below 12%.

Rating Factors

FortisBC Energy (Vancouver Island) Inc.

Regulated Electric and Gas Utilities [1][2]	**Current 12/31/2012**		[3]**Moody's 12-18 month Forward View As of Date Published**	
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%)				
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%)	4.6x	A	3.6 - 4.3x	Baa
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	17%	Baa	16 -18%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	13%	Baa	11 - 14%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	51%	Baa	45 - 52%	Baa
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		A3		A3

Source: Moody's Financial Metrics TM

[1] All ratios are calculated using Moody's Standard Adjustments. [2] Based on financial data as of 12/31/2012. [3] This represents Moody's forward view; not the view of the issuer.

Rating Report

Report Date:
March 18, 2013
Previous Report
August 8, 2012

Insight beyond the rating.

FortisBC Energy Inc.

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The Company
FortisBC Energy Inc. (FEI or the Company) is the largest natural gas distributor in British Columbia, serving approximately 841,000 customers (at the end of 2012) and representing approximately 90% of British Columbia's natural gas users. The Company is 100% owned by FortisBC Holdings Inc. (FHI; rated BBB (high)), which is a wholly-owned subsidiary of Fortis Inc. (rate A (low)).

Commercial Paper Limit
$500 million

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
MTNs & Unsecured Debentures	A	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

DBRS has confirmed the ratings of FortisBC Energy Inc. (FEI or the Company) as listed above. The Medium-Term Notes (MTNs) and Unsecured Debentures (Debentures) have the same rating as the Purchase Money Mortgages (PMMs) based on the following: (1) the outstanding amount of the PMMs is not significant (16% of the total); and (2) DBRS does not expect FEI to issue additional PMMs in the future. The ratings reflect FEI's low-risk business, predominantly regulated operations in an economically strong area, strong financial profile and reasonable regulatory environment.

FEI's low-risk business is underpinned by its regulated gas transmission and distribution operations (virtually all of FEI's earnings) and large customer base (approximately 841,000 or 90% of British Columbia's natural gas users at the end of 2012). Competition in the Company's franchise area remains primarily electricity, with FEI currently having a competitive operating cost advantage due to the current low natural gas price environment. The regulatory framework in British Columbia is viewed as reasonable in terms of cost recovery, returns on equity (ROE of 9.5%) and capital structure (40% equity). However, the Company's ROE and deemed equity could be affected in 2013 and beyond due to a regulatory review (see Regulation). Any regulatory change that may have a significant negative impact on FEI's earnings and cash flow could weaken the Company's credit profile.

The change to U.S. GAAP from Canadian GAAP, effective January 2012, did not have any rating implications (see Transition to U.S. GAAP). In addition, free cash flow, key credit metrics and debt leverage remained relatively stable in 2012. The Company expects to spend approximately $194 million on capital expenditures (capex) in 2013. DBRS expects FEI to continue to maintain its debt-to-capital ratio in line with the current rating category. In the absence of an adverse regulatory decision on FEI's ROE and capital structure, DBRS expects FEI's credit metrics to remain relatively stable, supported by higher earnings and cash flow.

Rating Considerations

Strengths
(1) Low business risk and reasonable regulation
(2) Economically strong service territory
(3) Stable and strong financial profile
(4) Large customer base

Challenges
(1) Volume risk
(2) Indirect access to the equity market
(3) Uncertain ROE and capital structure
(4) Competition from electricity

Financial Information

	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
FortisBC Energy Inc.	**For the year ended December 31st**				
(CA$ millions)	**2012**	**2011**	**2010**	**2009**	**2008**
EBIT gross interest coverage (1)	2.03	2.08	2.20	2.00	1.97
% debt in capital structure (1) (2)	58.9%	62.6%	62.6%	66.4%	66.4%
Cash flow/Total debt	13.9%	11.1%	10.9%	10.3%	10.1%
Net income before extra. Items	112	110	93	87	92
Cash flow from operations	237	193	177	170	166

(1) Adjusted for operating leases. (2) Certain US GAAP adjustments in 2012 and 2011 (see Transition to US GAAP on page 3) have been adjusted for comparative purposes.

Rating Considerations Details

Strengths

(1) **Low business risk and reasonable regulation.** FEI's generates virtually all of its earnings from its natural gas transmission and distribution operations, where competition is limited to other forms of energy (electricity). The regulatory framework in British Columbia is reasonable with respect to cost recovery and returns on investment. FEI is not exposed to commodity costs as natural gas costs are passed on to the customers, with quarterly adjustments.

(2) **Economically strong service territory.** FEI operates in an economically strong service area that includes the City of Vancouver. The customer mix is weighted toward residential and commercial customers (roughly 89% of distribution revenues and 61% of throughput for the year-end 2012), whose consumption is less sensitive to economic conditions.

(3) **Stable and strong financial profile.** FEI has maintained its capital structure in line with the approved regulatory capital structure. The debt-to-capital of 58.9% (adjusted for goodwill and "lease-in lease-out" arrangement under US GAAP) and EBIT interest coverage of 2.03 times (x) in 2012 are commensurate with its current rating category. DBRS notes that FEI's cash flow-to-debt ratio has improved consistently since 2008 and was in line with the "A" rating category in 2012.

(4) **Large customer base.** FEI had a large customer base of approximately 841,000 at the end of 2012. This represented approximately 90% of natural gas users in British Columbia.

Challenges

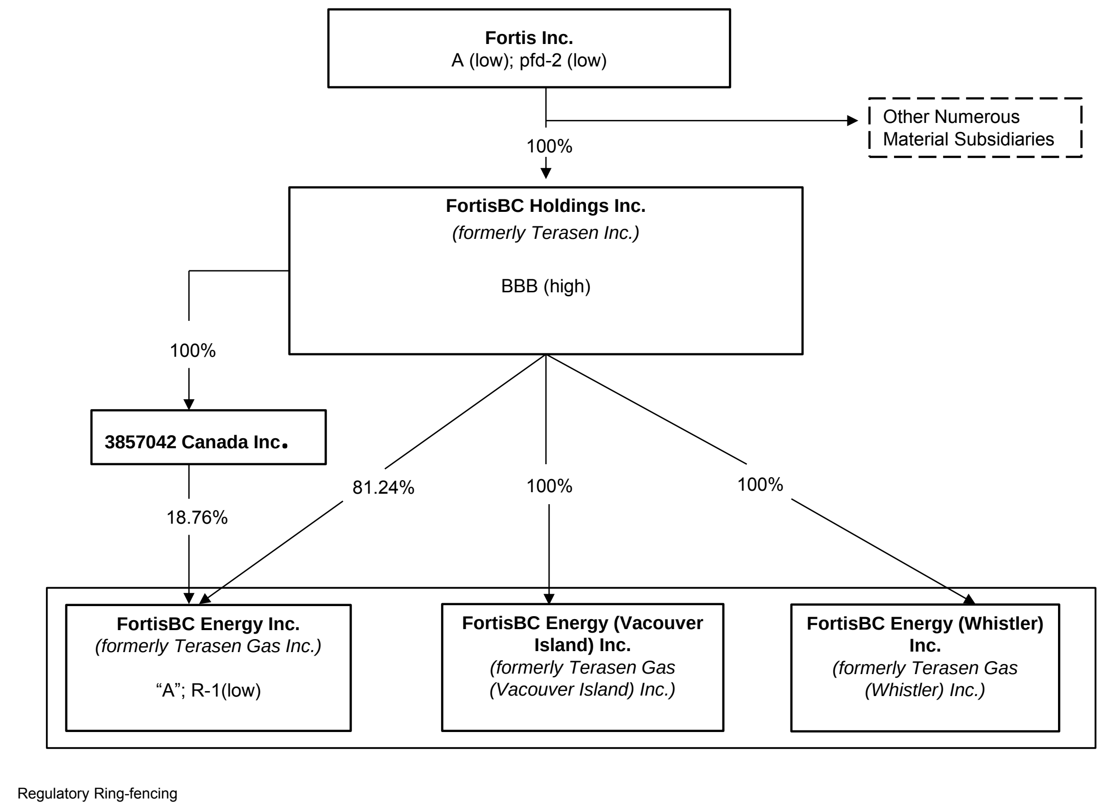
(1) V**olume risk.** The Company is exposed to volume risk on industrial, transportation and other customers, who accounted for approximately 39% of the Company's total throughput in 2012 (around 11% of revenue). The usage of these customers, such as those in the pulp and paper industries, is sensitive to economic conditions.

(2) **Indirect access to the public equity market.** FEI has no direct access to the public equity market. As a result, it finances cash flow deficits by managing its dividend payouts to the parent and through equity issuances to the parent, as well as other debt issuances. The company's current rating incorporates DBRS's expectation that the parent will continue to provide equity financing support in the future.

(3) **Uncertain ROE and capital structure.** In April 2012, the BCUC issued a final scoping document identifying the items that will be reviewed as part of Generic Cost of Capital (GCOC) Proceeding, which includes, among other things: (1) the cost of capital for a benchmark low-risk utility effective January 2013; and (2) whether a ROE automatic adjustment mechanism is warranted, which would be implemented January 2014. The decision is expected mid-year 2013. The GCOC decision could have a negative impact on FEI's earnings in 2013 and beyond.

(4) **Competition from electricity.** Natural gas distribution operators in British Columbia face more intense competition from electricity than other provinces in Canada (except Québec) due to the low power costs in British Columbia.

Simplified Organization Chart as of December 31, 2012



Amalgamation Update

In April 2012 FEI, together with FEVI and FEW, applied to the BCUC for the necessary approvals to amalgamate the three utilities and implement postage stamp rates across the service territories served by the amalgamated entity, effective January 1, 2014. The evidentiary portion of the proceeding was closed in October 2012 and a decision was received in February 2013. In its decision, the BCUC denied the request to implement postage stamp rates and as a result, the companies will not be proceeding with an amalgamation.

Transition to US GAAP

- Effective January 1, 2012, FEI adopted US GAAP and has restated the comparative reporting period. The major impact on key credit ratios in this report reflects the following changes as at December 31, 2011:
  (1) Total assets increased by approximately $951 million due primarily to increases in regulatory assets, plant and equipment and goodwill in accordance with US GAAP.
  (2) Total liabilities increased by approximately $202 million due primarily to increases in long-term debt and capital lease obligations and pension liabilities in accordance with US GAAP.
  (3) The equity base increased by approximately $750 million. The increase was due primarily to the application of push-down accounting, which was effective May 17, 2007 as a result of the Fortis acquisition.
- DBRS has adjusted for goodwill and "lease-in lease-out" arrangements for the debt-to-capital ratio under US GAAP for comparative purposes.
- The transition from Canadian GAAP to US GAAP did not have an impact on the current ratings.

FortisBC Energy Inc.

Report Date:
March 18, 2013

Earnings and Outlook

	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
Consolidated Income Statement	**For the year ended December 31st**				
(CA$ millions)	**2012**	**2011**	**2010**	**2009**	**2008**
EBITDA (1)	369	333	317	297	292
EBIT (1)	241	241	226	214	214
Gross interest expense (1)	119	118	104	109	111
Pre-tax income	123	126	123	106	103
Income tax	11	16	30	19	12
Net income before extra. items	112	110	93	87	92
Reported net income	112	110	93	87	92
Return on avg. common equity (2)	10.4%	10.7%	9.8%	9.9%	10.4%
Rate Base	2,717	2,636	2,540	2,547	2,510
Approved common equity	40.0%	40.0%	40.0%	35.0%	35.0%
Allowed ROE	9.50%	9.50%	9.50%	8.99%	8.62%

(1) Less inter-company interest payments.

(2) Certain US GAAP adjustments in 2012 and 2011 (see Transition to US GAAP on page 3) have been adjusted for comparative purposes.

2012 Summary

- Earnings were higher in 2012 primarily due to the increased rate base, higher margin from industrial customers, higher contribution from the current year tax loss utilization plan and lower-than-forecast operation and maintenance expenditures.
  - However, these were partially offset by lower margins associated with lower-than-forecast customer additions in 2012 and lower capitalized allowance for funds used during construction compared to the same period in 2011.
- Volume usage volatility as a result of changes in weather conditions is mitigated by the revenue stabilization adjustment mechanism (RSAM), which allows FEI to defer variances due to changes in usage rates, to be recovered/refunded over the subsequent three years.

2013 Outlook

- The Company’s 2013 earnings are expected to increase modestly as the rate base continues to grow, reflecting ongoing capex.
- Although the decision on the current GCOC Proceeding could have a negative impact on FEI’s future earnings, DBRS does not expect the impact to be significant.

Financial Profile

Consolidated Cash Flow Statement	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
	For the year ended December 31st				
(CA$ millions)	**2012**	**2011**	**2010**	**2009**	**2008**
Net income before extra. items	112	110	93	87	92
Depreciation & amortization	128	92	91	83	78
Deferred income taxes/Other	(3)	(9)	(7)	0	(4)
Cash flow from operations	237	193	177	170	166
Dividends paid	(85)	(85)	(84)	(67)	(100)
Capex	(160)	(169)	(157)	(139)	(123)
Free cash flow before WC	(8)	(61)	(64)	(36)	(57)
Changes in working capital (WC)	14	84	(15)	16	33
Changes in regulatory assets & liabilities	(31)	(10)	0	0	0
Net free cash flow	(25)	13	(79)	(20)	(24)
Acquisitions	0	0	0	0	0
Assets sales/Divestitures	0	0	0	0	14
Net changes in equity	65	0	125	0	0
Net changes in debt	(36)	(15)	(24)	6	(5)
Other/Adjustments by DBRS	1	4	(13)	7	22
Change in cash	5	2	9	(7)	7
Total debt	1,701	1,737	1,623	1,647	1,640
Total debt in capital structure	47.4%	49.1%	61.3%	65.2%	65.2%
Total debt in capital structure (1) (2)	58.9%	62.6%	62.6%	66.4%	66.4%
Cash flow/Total debt	13.9%	11.1%	10.9%	10.3%	10.1%
EBIT gross interest coverage (1)	2.03	2.08	2.20	2.00	1.97
Total debt/EBITDA	4.61	5.22	5.13	5.55	5.62
Capex/Depreciation	1.25	1.84	1.72	1.68	1.57
Dividend payout ratio	75.9%	77.3%	90.1%	76.8%	109.3%

(1) Adjusted for operating leases.

(2) Certain US GAAP adjustments in 2012 and 2011 (see Transition to US GAAP on page 3) have been adjusted for comparative purposes.

2012 Summary

- Cash flow from operations has increased steadily, reflecting the Company's growing earnings.
- Capital investments to support load growth and system reliability have also increased considerably over the past few years. This, combined with high dividend payouts (an average payout ratio of 86% of earnings over the last five years), has resulted in free cash flow deficits.
  - The Company continued to manage its dividend payouts and equity issuances so that its capital structure is in line with the conditions imposed by the BCUC, which stipulates that FEI must maintain its capital structure in line with the regulatory structure.
- In April 2012, the Company issued $65 million in equity to its parent due to a higher rate base in 2012 compared to 2011, as a result of capital projects going into service in early 2012.
- FEI's credit metrics remained stable in 2012 and were commensurate with the current rating.

2013 Outlook

- Free cash flow deficits are expected to continue as capex is expected to be approximately $194 million in 2013, before contributions in aid of construction, largely due to the sustaining capital program.
- DBRS expects FEI to continue to finance its capex through dividend management and equity and debt issuances in a manner that maintains its capital structure in line with its current rating range.

FortisBC Energy Inc.

Report Date:
March 18, 2013

Long-Term Debt and Liquidity

Liquidity

Credit Facilities (December 31, 2012)	Committed	Short-Term Notes	Letters of Credit	Available	Expiry
(CA$ millions)					
Syndicated unsecured credit facility	500	33	51	416	Aug-14
Total	500	33	51	416	

- The credit facility is primarily used to support FEI's $500 million commercial paper program.
- Due to the seasonal nature of the business, liquidity requirements peak in the fall and winter.
- DBRS views FEI's liquidity as sufficient for its funding requirements during the peak period, given its stable cash flow and modest long-term debt due in the near term.

Long-Term Debt, Capita Lease & Finance Obligations Maturity Schedule

(CA$ millions)	2013	2014	2015	2016	2017	Thereafter
Debt instruments	7.0	7.0	82.0	207.0	7.0	1,358.0
% of total	0%	0%	5%	12%	0%	81%

- The Company's near-term refinancing risk remains modest, as the debt maturity schedule is light until 2016 when approximately $207 million (or 12%) of total debt will be due.
- DBRS believes that refinancing of the debt maturity is manageable, given the Company's strong credit profile.

Debt Instruments

Debt Instruments	2012	2011
(CA$ millions)		
Secured Purchase Money Mortgages	275	275
Unsecured Debentures and MTNs	1,270	1,270
Capital lease and finance obligation	123	127
Total	1,668	1,672
Credit facilities	33	65
Less: Current portion	(7)	(7)
Total	1,694	1,730

- MTNs and Unsecured Debentures have the same rating as PMMs based on the following: (1) the outstanding amount of the PMMs is not significant (only around 16% of the total debt); and (2) DBRS does not expect FEI to issue new PMMs in the future.
- The bank facility is unsecured but is rated equally with the Company's secured and unsecured debt.

Regulation

Overview

DBRS views the regulatory framework in British Columbia as reasonable, as it allows FEI to earn a reasonable return on its capital investment and to recover prudently incurred operating costs. In addition, the Company does not have exposure to gas price risk since costs are generally passed through to the customers, subject to a reasonable regulatory lag. FEI is regulated by the BCUC.

- The BCUC uses a future test year to establish rates for a utility. FEI forecasts the volume of gas to be sold, gas supply costs and all operating costs that are incurred in the test year.
- The BCUC will set rates to permit FEI to collect all of its approved forecast costs.
- FEI has a number of deferral accounts that are used to ameliorate unanticipated changes in certain forecast items, including the following two mechanisms:

(1) Commodity Cost Reconciliation Account and Midstream Cost Reconciliation Account:

- Any differences between actual and forecast gas costs are captured and recorded in these deferral accounts to be recovered or refunded in future rates.
- Forecast gas prices are adjusted on a quarterly basis for the commodity rates, mitigating the impact of the recovery lag.

(2) Revenue Stabilization Adjustment Mechanism:

- The RSAM seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in forecast versus actual customer usage throughout the year to recover them in rates over the following three years. This reduces FEI's earnings volatility.
- Volume variances from large-volume industrial, transportation and other customers, which account for approximately 39% of FEI's total throughput (2012), are not included in this deferral account. However, these customers' usage is more predictable and less likely to be significantly affected by weather, even though it is sensitive to economic conditions.

Rates

- Prior to 2010, FEI operated under a performance-based rate plan.
- In 2010 through 2012, FEI operated under traditional cost-of-service rate making.
- In April 2012, the BCUC issued a decision on the FortisBC Utilities (collectively consisting of FEI, FEVI and FEW) 2012/2013 Revenue Requirement Application.
  - The final delivery rate increase effective January 1, 2012, was 4.2% (a decrease of approximately 1.4% as compared to FEI's existing interim delivery rates for 2012).
  - The difference between interim rates and final rates was refunded to customers starting June 1, 2012.
- From 2010 through 2012, the Company's ROE and deemed equity were at 9.50% and 40%, respectively.

Generic Cost of Capital Proceeding

- In April 2012, the BCUC issued a final scoping document identifying the items that will be reviewed as part of GCOC Proceeding.
  - These include, among other things: (1) the cost of capital for a benchmark low-risk utility effective January 2013; and (2) whether a ROE automatic adjustment mechanism is warranted, which would be implemented January 2014.
  - The decision is expected mid-year 2013 and could have a negative impact on FEI's earnings in 2013 and beyond.

Regulatory Ring-Fencing

- The regulatory ring-fencing imposed on FEI by the BCUC at the time Fortis Inc. acquired FEI in 2007 (a continuation of the ring-fencing imposed upon acquisition of the former Terasen Inc. by Kinder Morgan Inc. in 2005) is intended to ensure that public interest is protected and that FEI will continue to operate as a separate, stand-alone entity without undue parental influence. One of these conditions is that FEI must maintain its debt-to-capital ratio in line with the regulatory capital structure.

FortisBC Energy Inc.

Report Date:
March 18, 2013

FortisBC Energy Inc.

Balance Sheet	USGAAP	USGAAP	CGAAP		USGAAP	USGAAP	CGAAP
(CA$ millions)	**Dec. 31**	**Dec. 31**	**Dec. 31**		**Dec. 31**	**Dec. 31**	**Dec. 31**
Assets	**2012**	**2011**	**2010**	**Liabilities & Equity**	**2012**	**2011**	**2010**
Cash & equivalents	22	17	15	S.T. borrowings	33	65	178
Accounts receivable	205	238	298	Current portion of debt	7	7	3
Inventories	95	101	136	Accounts payable	226	304	358
Current regulatory assets	28	73	0	Current regulatory liabilities	35	23	0
Others	16	13	108	Others	32	38	53
Total Current Assets	**366**	**442**	**557**	**Total Current Liabilities**	**333**	**437**	**591**
Net fixed assets	2,604	2,573	2,466	Long-term debt	1,661	1,665	1,442
Deferred income taxes	0	0	0	Deferred income taxes	309	298	280
Goodwill & intangibles	890	886	95	Regulatory liabilities	55	54	0
Regulatory assets	561	514	0	Other L.T. liabilities	194	185	149
Investments & others	22	23	366	Shareholders equity	1,891	1,799	1,023
Total Assets	**4,443**	**4,438**	**3,484**	**Total Liab. & SE**	**4,443**	**4,438**	**3,484**

	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
Balance Sheet &	**For the year ended December 31st**				
Liquidity & Capital Ratios	**2012**	**2011**	**2010**	**2009**	**2008**
Current ratio	1.10	1.01	0.94	0.88	0.80
Total debt in capital structure	47.4%	49.1%	61.3%	65.2%	65.2%
Total debt in capital structure (1) (2)	58.9%	62.6%	62.6%	66.4%	66.4%
Cash flow/Total debt	13.9%	11.1%	10.9%	10.3%	10.1%
Cash flow/Total debt (1)	13.8%	10.5%	10.3%	9.8%	9.6%
Cash flow/Capex	1.48	1.14	1.14	1.13	1.22
(Cash flow - Dividends)/Capex	0.95	0.64	0.59	0.74	0.54
Approved common equity	40.0%	40.0%	40.0%	35.0%	35.0%
Dividend payout ratio	75.9%	77.3%	90.1%	76.8%	109.3%
Coverage Ratios (times)					
EBIT gross interest coverage	2.03	2.04	2.17	1.96	1.92
EBITDA gross interest coverage	3.10	2.82	3.04	2.72	2.62
Fixed-charges coverage	2.03	2.04	2.17	1.96	1.92
Debt/EBITDA	4.61	5.22	5.13	5.55	5.62
EBIT gross interest coverage (1)	2.03	2.08	2.20	2.00	1.97
Profitability Ratios					
EBITDA margin	60.0%	56.5%	55.3%	56.4%	57.0%
EBIT margin	39.2%	40.9%	39.4%	40.7%	41.7%
Profit margin	18.2%	18.7%	16.3%	16.5%	17.9%
Return on avg. common equity (2)	10.4%	10.7%	9.8%	9.9%	10.4%
Return on capital (2)	7.3%	7.1%	6.2%	6.2%	6.4%
Allowed ROE	9.5%	9.5%	9.5%	9.0%	8.6%

(1) Adjusted for operating leases.

(2) Certain US GAAP adjustments in 2012 and 2011 (see Transition to US GAAP on page 3) have been adjusted for comparative purposes.

FortisBC Energy Inc.

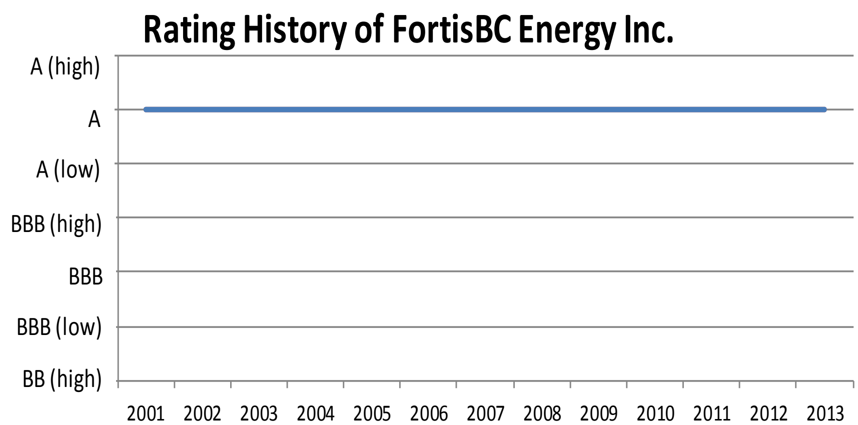
Report Date:
March 18, 2013

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
MTNs & Unsecured Debentures	A	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating History

Debt Rated	Current	2012	2011	2010	2009	2008
Issuer Rating	A	A	NR	NR	NR	NR
MTNs & Unsecured Debentures	A	A	A	A	A	A
Purchase Money Mortgages	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)



Note:
All figures are in Canadian dollars unless otherwise noted.

Rating Report
Report Date:
March 18, 2014
Previous Report
March 18, 2013

Insight beyond the rating.

FortisBC Energy Inc.

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The Company

FortisBC Energy Inc. (FEI or the Company) is the largest natural gas distributor in British Columbia, serving approximately 850,000 customers (at the end of 2013) and representing approximately 85% of British Columbia's natural gas users (95% after the amalgamation). The Company is 100% owned by FortisBC Holdings Inc. (FHI; rated BBB (high)), which is a wholly-owned subsidiary of Fortis Inc.

Commercial Paper Limit

$500 million

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
MTNs & Unsecured Debentures	A	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

DBRS has confirmed the ratings of FortisBC Energy Inc. (FEI or the Company) as listed above. The Medium-Term Notes (MTNs) and Unsecured Debentures (Debentures) have the same rating as the Purchase Money Mortgages (PMMs), based on the following: (1) the outstanding amount of the PMMs is not significant (16% of total debt) and (2) DBRS does not expect FEI to issue additional PMMs in the future. The ratings reflect FEI's good financial profile, low-risk business underpinned by its regulated distribution operation in an economically strong area, and a reasonable regulatory environment.

On February 26, 2014, the British Columbia Utilities Commission (BCUC) issued a decision on FortisBC Energy Utilities' (the FEU) Application for Amalgamation and Rate Design (the Decision). The FEU comprises FEI, FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW). DBRS viewed the Decision as credit neutral to FEI (for more information, see DBRS press release dated February 26, 2014).

FEI's business risk is reflective of an "A" rating category, supported by the following factors: (1) FEI, as a regulated natural gas distributor, has no exposure to gas price risk and (2) FEI serves a large customer base in an economically strong franchise area. In May 2013, the BCUC issued a decision on the first stage of the Generic Cost of Capital (GCOC) Proceeding. In the decision, the benchmark utility's (which is determined to be FEI) return on equity (ROE) would be set at 8.75% and deemed equity at 38.5%, both effective January 1, 2013 and unchanged in 2014 (ROE and deemed equity in 2012 were 9.50% and 40%, respectively). This unfavourable decision negatively affects FEI's earnings. In June 2013, FEI filed a Multi-Year Performance Based Ratemaking (PBR) Plan for 2014 through 2018. The BCUC approved a refundable interim increase for 2014 of 1.4%, with a final decision expected in Q3 2014. FEI's large customer base should allow FEI to maintain a good level of efficiency during the PBR period, in which an annual delivery rate increase is set under a formula approach for operating and capital costs.

FEI's credit metrics remained in the "A" rating range. FEI's 2014 capex is estimated to increase to nearly $300 million (including cost of removal) before customer contributions. This increase is largely associated with the Tilbury LNG Facility Expansion Project (See the Tilbury Project Section). DBRS expects FEI to prudently fund its 2014 capex program and maintain its credit metrics in line with DBRS's "A" rating range.

Rating Considerations

Strengths
(1) Relatively low business risk
(2) Economically strong service territory
(3) Good financial profile
(4) Large customer base

Challenges
(1) Volume risk
(2) Uncertainty about the PBR Plan
(3) Indirect access to the equity market
(4) Competition from electricity

Financial Information

	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP
FortisBC Energy Inc.		**For the year ended December 31st**			
(CA$ millions)	**2013**	**2012**	**2011**	**2010**	**2009**
EBIT gross interest coverage (1)	1.99	2.03	2.08	2.20	2.00
% debt in capital structure (1) (2)	60.3%	58.9%	62.6%	62.6%	66.4%
Cash flow/Total debt	14.3%	13.9%	11.1%	10.9%	10.3%
Net income before extra. Items	104	112	110	93	87
Cash flow from operations	251	237	193	177	170

(1) Adjusted for operating leases.
(2) Certain US GAAP adjustments in 2013, 2012 and 2011 have been adjusted for comparative purposes (see P6).

Rating Considerations Details

Strengths

(1) **Relatively low business risk.** FEI's business risk is viewed as relatively low, supported by the following factors: (a) FEI generates virtually all of its earnings from its regulated natural gas distribution and transportation operations, where competition is limited to other forms of energy (electricity); (b) FEI is not exposed to commodity price risk as natural gas costs are passed on to the customers, with adjustments made through quarterly review and application to the BCUC; and (c) volatility in usage by residential and commercial customers caused by the impact of the weather is mitigated through a deferral account (see Regulation Section). DBRS notes that the May 2013 BCUC decision on the first stage of the GCOC Proceeding was unfavourable. The decision determined that the ROE would be set at 8.75% and the deemed equity component at 38.5% for a benchmark utility, which was determined to be FEI, both effective January 1, 2013.

(2) **Economically strong service territory.** FEI operates in an economically strong service area that includes the City of Vancouver. The customer mix is weighted toward residential and commercial customers, whose consumption is less sensitive to economic conditions.

(3) **Good financial profile.** FEI has maintained its capital structure in line with the approved regulatory capital structure. All of the Company's credit metrics at the end of 2013 were indicative of the "A" rating category. These metrics are expected to remain stable going into 2014, as the Company is expected to continue to finance its future capex and maintain its balance-sheet leverage in line with the regulatory approved capital structure.

(4) **Large customer base.** FEI had a large customer base of approximately 850,000 at the end of 2013. This represented approximately 85% of natural gas users in British Columbia (BC) (95% after the amalgamation of FEI, FEVI and FEW).

Challenges

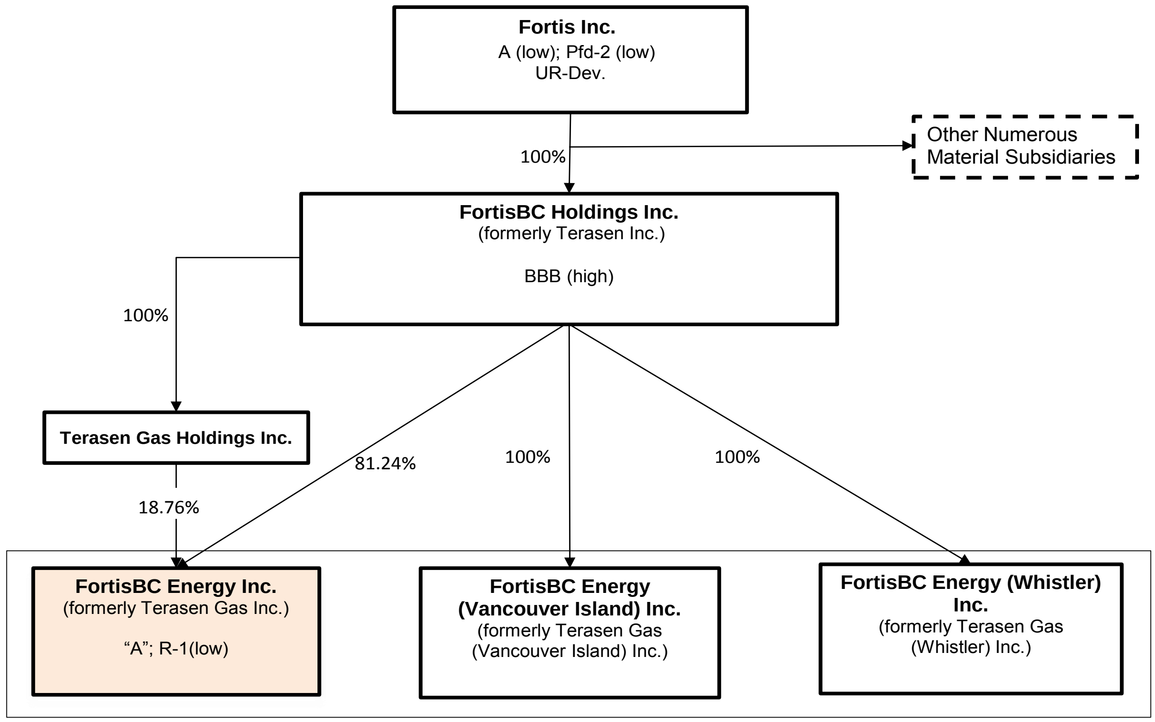
(1) V**olume risk.** The Company is exposed to volume risk on industrial, transportation and other customers, who accounted for approximately 38% of the Company's total throughput in 2013. The usage of these customers, such as those in the pulp and paper industries, is sensitive to economic conditions.

(2) **Uncertain outcome of the PBR plan.** There are uncertainties regarding the regulatory decision on the PBR plan for the 2014-2018 period. In June 2013, the Company filed an application for a multi-year performance based ratemaking plan. The BCUC is in the process of reviewing the application, with a decision expected in Q3 2014. There are no assurances that the rate orders to be issued will allow FEI to recover all costs actually incurred to provide utility services and to earn the expected ROE. Should the decision on the PBR plan be unfavourable with respect to the recovery of operating & maintenance cost and capital investment, it could have a negative impact on FEI's cash flow and credit metrics.

(3) **Indirect access to the public equity market.** FEI has no direct access to the public equity market. As a result, it finances cash flow deficits by managing its dividend payouts and equity issuances to the parent, as well as other debt issuances. The Company's current rating incorporates DBRS's expectation that the parent will continue to provide equity financing support in a timely manner if required.

(4) **Competition from electricity.** Natural gas distribution operators in British Columbia face more intense competition from electricity than other provinces in Canada (except Québec), due to the low power costs in British Columbia. DBRS notes that the electricity retail rates in BC are expected to increase considerably over the next two years, thereby potentially reducing the competition.

Simplified Organization Chart as of December 31, 2013



Amalgamation Update

- On February 26, 2014, the British Columbia Utilities Commission (BCUC) issued a decision on FortisBC Energy Utilities' (the FEU) Application for Amalgamation and Rate Design (the Decision). The FEU comprises FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW).
- DBRS viewed the Decision as credit neutral to FEI, reflecting the following factors:
  (1) The business risk profile of the amalgamated entity would not significantly change from FEI's current business risk level. This reflects the fact that the amalgamated entity will have a modestly larger customer base than FEI and that risk attributable to the small size of FEVI and FEW, combined with their higher rates, will be eliminated following the amalgamation.
  (2) The BCUC recommends that the return on equity (ROE) and capital structure remain the same for the amalgamated entity as for FEI; however, the final determination as to the appropriate ROE and capital structure is deferred to the Generic Cost of Capital (GCOC) Proceeding.
- See DBRS press release dated February 26, 2014, for further details.

The Tilbury LNG Facility Expansion Project

In November 2013, an Order in Council (Special Direction) was signed by the Province to allow FEI to expand its LNG facilities at Tilbury Island (BC) (the Expansion Project). The Special Direction set out a number of requirements for the BCUC as follows:

(1) The Expansion Project is exempt from a Certificate of Public Convenience and Necessity (CPCN) process; and
(2) The upper limit for the cost related to the expansion project is $400 million; and
(3) FEI is allowed to recover the cost of the Expansion Project from customers.

The Expansion Project is expected to provide incremental cash flow once it is put in service, expected to be in 2016.

FortisBC Energy Inc.

Report Date:
March 18, 2014

Earnings and Outlook

FortisBC Energy Inc.	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP
Consolidated Income Statement	**For the year ended December 31st**				
(CA$ millions)	**2013**	**2012**	**2011**	**2010**	**2009**
EBITDA (1)	382	369	333	317	297
EBIT (1)	234	241	241	226	214
Gross interest expense (1)	118	119	118	104	109
Pre-tax income	118	123	126	123	106
Income tax	14	11	16	30	19
Net income before extra. items	104	112	110	93	87
Reported net income	104	112	110	93	87
Return on avg. common equity (2)	9.4%	10.4%	10.7%	9.8%	9.9%
Rate Base	2,777	2,725	2,636	2,540	2,547
Approved common equity	38.5%	40.0%	40.0%	40.0%	35.0%
Allowed ROE	8.75%	9.50%	9.50%	9.50%	8.99%

(1) Less inter-company interest payments.
(2) Certain US GAAP adjustments in 2013, 2012 and 2011 have been adjusted for comparative purposes (see P6).

2013 Summary

- **Overall:** Net earnings were lower in 2013, negatively affecting the interest coverage metrics (see next page), though the impact was modest. Lower earnings reflected the following factors:
  (1) Lower allowed ROE (8.75% in 2013 versus 9.50% in 2012), lower equity portion of the capital structure (38.5% in 2013 versus 40% in 2012), lower than forecast margin for transportation customers and higher income taxes.
  (2) The decrease is partially offset by lower than forecast finance charges, lower operation and maintenance expenses, higher rate base and higher allowance for funds during construction.
- Volume usage volatility as a result of changes in weather conditions is mitigated by the revenue stabilization adjustment mechanism (RSAM), which allows FEI to defer variances due to changes in usage rates, to be recovered/refunded over the subsequent three years. The Company has applied for these amounts to be recovered in rates over two years, starting January 2014. RSAM only applies to residential and commercial customers.

2014 Outlook

- 2014 earnings are expected to increase modestly as the rate base continues to grow, while the ROE and deemed equity component remain the same as they were in 2013.
- Effective January 2014, the BCUC approved for a 1.4% increase in interim rates to be refundable. The final decision on the 2014-2018 PBR Plan is expected in Q3 2014.

FortisBC Energy Inc.

Report Date:
March 18, 2014

Financial Profile

FortisBC Energy Inc.	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP
Consolidated Cash Flow Statement	**For the year ended December 31st**				
(CA$ millions)	**2013**	**2012**	**2011**	**2010**	**2009**
Net income before extra. items	104	112	110	93	87
Depreciation & amortization	148	128	92	91	83
Deferred income taxes/Other	(1)	(3)	(9)	(7)	0
Cash flow from operations	251	237	193	177	170
Dividends paid	(131)	(85)	(85)	(84)	(67)
Capex	(159)	(159)	(169)	(157)	(139)
Free cash flow before WC	(39)	(7)	(61)	(64)	(36)
Changes in working capital (WC)	8	14	84	(15)	16
Changes in regulatory assets & liabilities	(29)	(17)	(10)	0	0
Net free cash flow	(60)	(10)	13	(79)	(20)
Acquisitions	0	0	0	0	0
Assets sales/Divestitures	0	0	0	0	0
Net changes in equity	0	65	0	125	0
Net changes in debt	50	(36)	(15)	(24)	6
Other/Adjustments by DBRS	(12)	(14)	4	(13)	7
Change in cash	(22)	5	2	9	(7)
Total debt	1,751	1,701	1,737	1,623	1,647
Total debt in capital structure	48.4%	47.4%	49.1%	61.3%	65.2%
Total debt in capital structure (1) (2)	60.3%	58.9%	62.6%	62.6%	66.4%
Cash flow/Total debt	14.3%	13.9%	11.1%	10.9%	10.3%
EBIT gross interest coverage (1)	1.99	2.03	2.08	2.20	2.00
Total debt/EBITDA	4.58	4.61	5.22	5.13	5.55
Dividend payout ratio	126.0%	75.9%	77.3%	90.1%	76.8%

(1) Adjusted for operating leases.

(2) Certain US GAAP adjustments in 2013, 2012 and 2011 have been adjusted for comparative purposes (see P6).

2013 Summary

- FEI's financial profile remained relatively stable in 2013, with slightly higher debt leverage, modestly lower interest coverage ratio, but stronger cash flow ratios. All credit metrics remained within DBRS's "A" rating category.
- Despite lower earnings (as discussed in the Earnings Section), cash flow increased modestly in 2013 over 2012, largely reflecting high depreciation as the rate base grew.
- While capex remained stable in 2013, dividends increased to maintain FEI's capital structure to be in line with the regulatory capital structure.

2014 Outlook

- 2014 capex before contributions in aid of construction and including cost of removal is estimated to be approximately $296 million, which is much higher than the amount spent in the previous two years. As a result, the free cash flow deficits are expected to continue.
- Approximately $100 million is expected to be allocated to the Expansion Project. The project has a capex limit of $400 million (set by a Special Direction issued by the Province) and is expected to be in service in 2016.
- DBRS expects FEI to continue to finance its capex through dividend management and equity and debt issuances in a manner that maintains its credit metrics in line with "A" rating range.

Long-Term Debt and Liquidity

Liquidity

Credit Facilities (December 31, 2013)	Committed	Short-Term Notes	Letters of Credit	Available	Expiry
(CA$ millions)					
Syndicated unsecured credit facility	500	87	50	363	Aug-2015
Total	500	87	50	363	

- The unsecured credit facility is primarily used to support FEI's $500 million commercial paper program.
- Due to the seasonal nature of the business, liquidity requirements peak in the fall and winter.
- DBRS views FEI's liquidity as sufficient for its funding requirements during the peak period, given its stable cash flow and a low natural gas price environment.

Long-Term Debt, Capital Lease & Finance Obligations Schedule

(CA$ millions)	2014	2015	2016	2017	2018	Thereafter	Total
Amount due	7	82	207	7	34	1,327	1,664.0
% of total	0%	5%	12%	0%	2%	80%	100%

- The Company's near-term refinancing risk remains modest, as the debt maturity schedule is light until 2016, when approximately $207 million (or 12%) of total debt will be due.
- DBRS believes that refinancing of the debt maturity is manageable, given the Company's strong credit profile.

Debt Instruments

Debt Instruments	2013	2012
(CA$ millions)		
Secured Purchase Money Mortgages (PMMs)	275	275
Unsecured Debentures and MTNs	1,270	1,270
Capital lease and finance obligation	119	123
Total	1,664	1,668
Credit facilities	87	33
Less: Current portion	(7)	(7)
Total	1,744	1,694

- MTNs and Unsecured Debentures have the same rating as PMMs based on the following: (1) the outstanding amount of the PMMs is viewed as not significant; and (2) DBRS does not expect FEI to issue new PMMs in the future.

Transition to US GAAP

- Effective January 1, 2012, FEI adopted US GAAP and has restated the comparative reporting period. The major impact on key credit ratios in this report reflects the following changes as at December 31, 2011:
  - (1) Total assets increased by approximately $951 million due primarily to increases in regulatory assets, plant and equipment and goodwill in accordance with US GAAP.
  - (2) Total liabilities increased by approximately $202 million due primarily to increases in long-term debt and capital lease obligations and pension liabilities in accordance with US GAAP.
  - (3) The equity base increased by approximately $750 million. The increase was due primarily to the application of push-down accounting, which was effective May 17, 2007 as a result of the Fortis acquisition.
- DBRS has adjusted for goodwill and "lease-in lease-out" arrangements for the debt-to-capital ratio under US GAAP for comparative purposes.

FortisBC Energy Inc.

Report Date:
March 18, 2014

Regulation

Overview

FEI operated under a traditional cost-of-service (COS) methodology from 2010 through 2013. Under this methodology, FEI was allowed to have an opportunity to recover its prudently-incurred operating and maintenance costs and prudently-incurred capital investment. In addition, the BC regulatory framework allows FEI to pass on all gas supply costs to customers (subject to reasonable regulatory lag) and to implement deferral accounts to mitigate the volatility of weather impact and gas price fluctuation.

Future test year

- Under the traditional COS methodology, the BCUC uses a future test year to establish rates for a utility. FEI forecasts the volume of gas to be sold, gas supply costs and all operating costs that are incurred in the test year. The BCUC will then set rates to permit FEI to collect all of its approved forecast costs.

Deferral Accounts

FEI has a number of deferral accounts that are used to ameliorate unanticipated changes in certain forecast items, including the following two mechanisms:

(1) Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA):

- Any differences between actual and forecast gas costs are captured and recorded in these deferral accounts to be recovered or refunded in future rates. Forecast gas prices are adjusted on a quarterly basis for commodity rates, mitigating the impact of recovery lag.

(2) Revenue Stabilization Adjustment Mechanism (RSAM):

- The RSAM seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in forecast versus actual customer usage throughout the year to recover them in rates over the following three years. This reduces FEI's earnings volatility.
- Volume variances from large-volume industrial, transportation and other customers are not included in this deferral account. However, these customers' usage is more predictable and less likely to be significantly affected by weather, even though it is sensitive to economic conditions.
- The RSAM and MCRA accounts are currently recovered/refunded in rates over three years. FEI has applied to the BCUC, requesting these amounts to be recovered/refunded over two years. The CCRA is anticipated to be fully recovered within the next fiscal year.

Generic Cost of Capital Proceeding (GCOC)

- In May 2013, the BCUC issued a decision on the first stage of the GCOC Proceeding, which determined that FEI's ROE and deemed equity would be set at 8.75% and 38.5% respectively, both effective January 1, 2013.
- Effective January 2014, the BCUC introduced an Automatic Adjustment Mechanism (AAM) to set the ROE on an annual basis. The AAM will be in effect if the actual long-term Government of Canada (GOC) bond yield exceeds 3.8%. The AAM did not take effect in 2014, since the GOC bond yield in October 2013 did not exceed the 3.8% threshold. As a result, the ROE for FEI in 2014 remains at 8.75%.

The 2014-2018 Performance Based Ratemaking (PBR) Plan

- In June 2013, FEI filed an application for a PBR Plan for 2014 through 2018.
- The PBR application assumes a forecast average rate base of approximately $2,778 million for 2014 and requests approval of a delivery rate increase of 1.4%, based on a formula approach for operating and capital costs and a continuation of this rate setting methodology through 2018.
- The BCUC approved for a 1.4% interim refundable rate increase, effective January 1, 2014. A decision on FEI's PBR application is expected to be rendered in Q3 2014.

Regulatory Ring-Fencing

- The regulatory ring-fencing imposed on FEI by the BCUC at the time of Fortis Inc.'s 2007 acquisition of FEI (a continuation of the ring-fencing imposed upon acquisition of the former Terasen Inc. by Kinder Morgan Inc. in 2005) is intended to ensure that public interest is protected and that FEI will continue to operate as a separate, stand-alone entity without undue parental influence. One of these conditions is that FEI must maintain its debt-to-capital ratio in line with the regulatory capital structure.

FortisBC Energy Inc.

Report Date:
March 18, 2014

FortisBC Energy Inc.

Balance Sheet (US GAAP)

(CA$ millions)	Dec. 31	Dec. 31	Dec. 31		Dec. 31	Dec. 31	Dec. 31
Assets	**2013**	**2012**	**2011**	**Liabilities & Equity**	**2013**	**2012**	**2011**
Cash & equivalents	0	22	17	S.T. borrowings	87	33	65
Accounts receivable	228	205	238	Current portion of debt	7	7	7
Inventories	81	95	101	Accounts payable	221	226	304
Current regulatory assets	18	28	73	Current regulatory liabilities	39	35	23
Others	13	16	13	Others	40	32	38
Total Current Assets	**340**	**366**	**442**	**Total Current Liabilities**	**394**	**333**	**437**
Net fixed assets	2,651	2,604	2,573	Long-term debt	1,657	1,661	1,665
Intangible assets	122	121	117	Deferred income taxes	327	309	298
Goodwill	769	769	769	Regulatory liabilities	55	55	54
Regulatory assets	560	561	514	Other L.T. liabilities	167	194	185
Others	22	22	23	Shareholders equity	1,864	1,891	1,799
Total Assets	**4,464**	**4,443**	**4,438**	**Total Liab. & SE**	**4,464**	**4,443**	**4,438**

Balance Sheet & Liquidity & Capital Ratios	**For the year ended December 31st** 2013	2012	2011	2010	2009
Current ratio	0.86	1.10	1.01	0.94	0.88
Total debt in capital structure	48.4%	47.4%	49.1%	61.3%	65.2%
Total debt in capital structure (1) (2)	60.3%	58.9%	62.6%	62.6%	66.4%
Cash flow/Total debt	14.3%	13.9%	11.1%	10.9%	10.3%
Cash flow/Total debt (1)	14.2%	13.8%	10.5%	10.3%	9.8%
Cash flow/Capex	1.58	1.49	1.14	1.13	1.22
(Cash flow - Dividends)/Capex	0.75	0.96	0.64	0.59	0.74
Approved common equity	38.5%	40.0%	40.0%	40.0%	35.0%
Dividend payout ratio	126.0%	75.9%	77.3%	90.1%	76.8%
Coverage Ratios (times)					
EBIT gross interest coverage	1.98	2.03	2.04	2.17	1.96
EBITDA gross interest coverage	3.24	3.10	2.82	3.04	2.72
Fixed-charges coverage	1.98	2.03	2.04	2.17	1.96
Debt/EBITDA	4.58	4.61	5.22	5.13	5.55
EBIT gross interest coverage (1)	1.99	2.03	2.08	2.20	2.00
Profitability Ratios					
EBITDA margin	60.3%	60.0%	56.5%	55.3%	56.4%
EBIT margin	37.0%	39.2%	40.9%	39.4%	40.7%
Profit margin	16.4%	18.2%	18.7%	16.3%	16.5%
Return on avg. common equity (2)	9.4%	10.4%	10.7%	9.8%	9.9%
Return on capital (2)	6.9%	7.3%	7.1%	6.2%	6.2%
Allowed ROE	8.75%	9.5%	9.5%	9.5%	9.0%

(1) Adjusted for operating leases.
(2) Certain US GAAP adjustments in 2013, 2012 and 2011 have been adjusted for comparative purposes (see P6).

FortisBC Energy Inc.

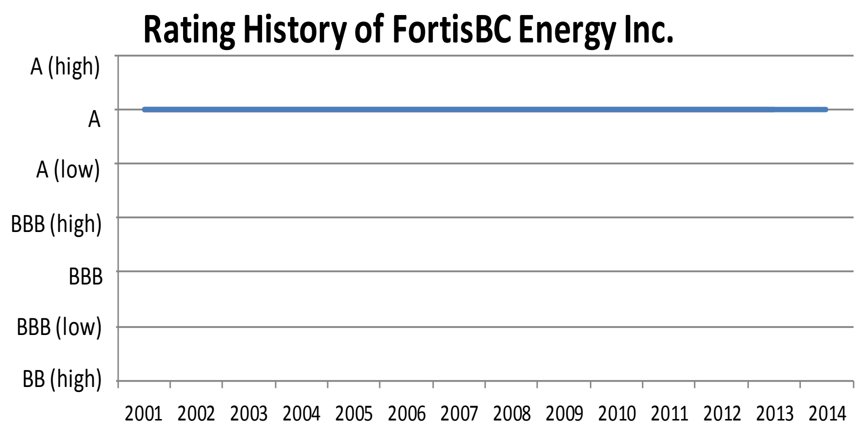
Report Date:
March 18, 2014

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
MTNs & Unsecured Debentures	A	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating History

Debt Rated	Current	2013	2012	2011	2010	2009
Issuer Rating	A	A	A	NR	NR	NR
MTNs & Unsecured Debentures	A	A	A	A	A	A
Purchase Money Mortgages	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)



Note:
All figures are in Canadian dollars unless otherwise noted.

MOODY'S
INVESTORS SERVICE

Credit Opinion: FortisBC Energy Inc.

Global Credit Research - 15 Jul 2014

Vancouver, British Columbia, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Secured -Dom Curr	A1
Senior Unsecured -Dom Curr	A3
Parent: FortisBC Holdings Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa2
FortisBC Energy (Vancouver Island) Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3

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Key Indicators

[1]**FortisBC Energy Inc.**

	3/31/2014(L)	12/31/2013	12/31/2012	[2]12/31/2011	12/31/2010
CFO pre-WC + Interest / Interest	2.5x	2.5x	2.4x	2.2x	2.7x
CFO pre-WC / Debt	14.9%	14.8%	14.1%	11.2%	10.6%
CFO pre-WC - Dividends / Debt	6.8%	7.1%	9.2%	6.5%	5.9%
Debt / Capitalization	42.7%	43.9%	44.5%	47.4%	59.1%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics [2] 2011 Key Indicators reflect the company's retrospective changes due to adoption of US GAAP, effective January1, 2012

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Credit supportive regulatory environment

Stable cash flow and weak financial metrics

Transition to PBR expected to have minimal credit implications

Amalgamation credit neutral to FEI

FEI is independent of ultimate parent, Fortis Inc

Corporate Profile

FortisBC Energy Inc. (FEI), headquartered in Vancouver, is the largest gas local distribution company (LDC) in British Columbia serving about 850,000 customers, over 90% of which are residential. FEI is regulated by the British Columbia Utilities Commission (BCUC). From 2010 to 2013, FEI's revenue requirement was determined under cost of service regulation. For the 2014-2018 period, FEI has proposed a return to performance based regulation (PBR), which was previously in effect from 2004 to 2009.

FEI is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI; Baa2 stable) which, in turn, is wholly owned by Fortis Inc. (FTS, not rated), a diversified electric and gas utility holding company. FHI also owns 100% of FortisBC Energy (Vancouver Island) Inc. (FEVI; A3 stable) and FortisBC Energy (Whistler) Inc. (FEW, not rated).

SUMMARY RATING RATIONALE

FEI's credit quality is driven by its credit supportive regulatory environment and its monopoly position. The company has a long term track record of earning its allowed return on equity and its cash flow continues to be highly predictable. This is offset by the company's weak financial metrics, with limited headroom at the current rating level, that are primarily a product of the allowed return on equity and its equity ratio.

DETAILED RATING CONSIDERATIONS

CREDIT SUPPORTIVE REGUALTORY ENVIRONMENT

FEI's investment grade rating is driven by its credit supportive regulatory environment and its monopoly position. Rates are typically set using a cost of service framework and a forward test year that enables the company to recover its costs and earn an allowed return established by the regulator, resulting in stable cash flow. The company has a track record of passing through its commodity costs in rates and has no direct exposure to commodity price risk and limited volume risk. To the extent that these and many other costs differ from forecast values, deferral or true up mechanisms limit exposure to forecast error. As a result the company has a long track record of earning the return on equity (ROE) established by the regulator.

For capital projects in excess of $5 million the company requires a certificate of public convenience and necessity (CPCN) that reduces the probability of cost disallowances, a credit positive. For large capital projects, the company receives a weighted average cost of capital in rates for financing costs incurred during construction; however, depreciation charges only begin once projects are complete and added to rate base. We do not believe the company has experienced any material cost disallowances. Decisions from the regulator tend to be reasonably predictable, consistent and transparent with a consultative approach. We have noted regulatory lag in some recent decisions, but the company has generally received interim rates as requested, mitigating some lag effects. Generally, when utility or other stakeholders materially disagree with some aspects of decisions, they have been successful in asking the regulator to review and vary its decisions with final outcomes acceptable to all parties as evidenced by a lack of court challenges. The company has access to the courts to challenge regulatory decisions, although we do not believe this has happened since the utility was acquired by Fortis Inc. The legislative and judicial underpinnings of the regulatory framework continue to be stable.

The company benefits from a monopoly position. We believe that its customers, who are primarily residential, continue to have the capacity and willingness to pay their bills.

STABLE CASH FLOW AND WEAK FINANCIAL METRICS

We expect the company to continue to generate stable cash flow, a key credit strength. Underpinning this stability, cash flow from operations is generally a function of the company's rate base, its deemed capital structure (38.5% equity layer effective 1/1/2013 - 12/31/2015), the allowed return on equity (currently 8.75%) and depreciation. The ROE contains an automatic adjustment mechanism for 2014 and 2015 that increases rates in case of rising interest rates - because of ongoing low interest rates 2014 does not qualify for an adjustment. We have incorporated into our analysis that the company continues to perform broadly in line with our expectations, including an assumption that the company will earn its allowed ROE. We expect the company's dividend policy net of any equity injections will maintain the deemed capital structure. The company is forecast to have limited financial metric headroom at the current rating. Planned large capital projects are expected to place some downward pressure on credit metrics, i.e., Tilbury LNG Expansion Project and the pipeline to serve the Woodfibre LNG (being developed at FEVI) because depreciation cash flow will not begin until these projects are in operation.

As a result, we forecast that credit metrics will decline somewhat until these projects are completed in 2016-17 and then improve modestly from the nadir that occurs prior to the in-service dates. This forecasted weakness is incorporated in the current rating.

TRANSITION TO PBR EXPECTED TO HAVE MINIMAL CREDIT IMPLICATIONS

FortisBC utilities have submitted detailed PBR proposals for both FEI and FBC for the period 2014-2018. We have assumed that it does not represent a material change in risk and that the company continues to earn its allowed ROE. The proposed PBR plan is broadly similar to the previous PBR plan and would have both an annual and mid-term review. FEI's proposal would set controllable O&M and non-CPCN (CPCN includes large capital projects that currently require regulatory pre-approval) capex by formula with substantial costs remaining as pass through items. The proposal contains a proposed symmetrical earnings sharing mechanism on up to 200bps and is subject to meeting service quality targets. Performance above or below the allowed ROE by more than 200bps would trigger an automatic review of the PBR plan. There are no proposed changes to key deferral accounts. While we don't expect it, a key risk to the proposal is that the regulator adopts very difficult efficiency targets within the formula. The PBR plan does not propose to modify support for CPCN capex. A final decision on the PBR is expected from the regulator in Q3 or Q4 2014. FEI previously operated under a PBR framework from 2004 to 2009 during which it earned its allowed ROE each year.

AMALGAMATION CREDIT NEUTRAL TO FEI

In February of 2014 the regulator determined that the amalgamation of FEI, FEVI and FEW is in the public interest. As a result we expect FEI, FEVI and FEW will report as a consolidated entity under the FEI name beginning Dec. 31, 2014. Current unsecured debt at FEVI will be assumed by FEI and will rank pari passu with existing FEI unsecured debt following amalgamation. FEVI and FEW are smaller utilities and they will benefit from the increase in scale that comes with the amalgamation with FEI. Their rates will decline as their higher costs are shared across a much larger customer base. Amalgamation is largely neutral to FEI as the increase in its customers' rates as a result of amalgamation are modest and will not affect its ability to recover its revenue requirement. Rate harmonization among the utilities will take place over a three year period. FEI's allowed ROE of 8.75% and an equity thickness of 38.5% would remain unchanged following amalgamation. FEVI's pipeline to serve Woodfibre LNG Expansion will place some modest additional pressure on FEI's amalgamated credit metrics during construction, a credit negative.

FEI IS INDEPENDENT OF ULTIMATE PARENT FORTIS INC

We consider FEI to be operationally and financially independent of ultimate parent Fortis Inc, although the company may periodically rely on its parent for equity injections to maintain its capital structure in line with the regulator's established parameters. Rate base of FortisBC companies accounts for over 45% of FTS's total rate base, although this will decline with Fortis Inc's planned acquisition of UNS Energy Corporation, expected to close at the end of 2014. We expect that Fortis Inc. would provide extraordinary support to FEI if required, provided that the parent had the economic incentive to do so. We believe that the parent will continue to have sufficient resources to provide support, if required. At March 31, 2014, FTS had a $1 billion committed revolving corporate facility at the FTS corporate level, of which $824 million was unused. Ring fencing provisions at FEI limit the ability of Fortis Inc to upstream cash, although we do not believe the parent would seek to increase leverage above levels established by the regulator.

Liquidity Profile

FEI has adequate liquidity.

For LTM 1Q14, FEI had negative free cash flow of $81 million as a result of $227 million CFO, $136 million dividends and $172 million capex. With the slated Tilbury LNG Expansion Project from 2014 to 2016, we estimate annual negative free cash flow at $110-140 million in 2014 on the basis of about $300 million capex and reduced annual dividends from the 2013 level. FEI is expected to manage dividend payouts and parent equity injections to maintain the equity layer close to the approved level of 38.5% along with its capex spending and borrowing profile. We expect FEI to raise additional debt post amalgamation to support both the Tilbury and Woodfibre projects.

FEI's has a $500 million syndicated credit facility maturing on August 24, 2015 that supports its $500 million commercial paper program. The company is currently well below the debt to total capitalization ratio covenant (maximum 75%) in the credit agreement. As of March 31, 2014, there was $403 million available under the facility.

FEI has limited near term debt obligations in the next 12-18 months: $75 million of debt maturity in September 2015 and $7 million capital lease obligation. The next material maturity is in September 2016 when $200 million of debt retires.

Rating Outlook

The stable outlook is based on our expectation of a stable regulatory environment and stable, albeit weak financial metrics with ongoing limited headroom at the current rating level.

What Could Change the Rating - Up

Given the ongoing forecast weakness in credit metrics an upgrade is unlikely. We could upgrade the company with a material sustained improvement in financial metrics, including CFO pre W/C to debt in the mid to high teens.

What Could Change the Rating - Down

While we don't expect it several factors could lead to a downgrade. For example, an unexpected, material adverse regulatory decision or forecast sustained deterioration in credit metrics including CFO/pre-W/C to debt of less than 11%.

Rating Factors

FortisBC Energy Inc.

Regulated Electric and Gas Utilities Industry Grid [1][2]	**Current LTM 3/31/2014**		[3][4]**Moody's 12-18 Month Forward ViewAs of June 2014**	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	2.4x	Ba	2.4 - 2.8x	Ba
b) CFO pre-WC / Debt (3 Year Avg)	13.9%	Baa	11 - 14%	Baa
c) CFO pre-WC - Dividends / Debt (3 Year Avg)	8.4%	Baa	6 - 9%	Ba
d) Debt / Capitalization (3 Year Avg)	44.1%	A	45 - 48%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. [2] As of 3/31/2014(L); Source: Moody's Financial Metrics [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. [4] Moody's forward view is based on FEI's post-amalgamation financial projections

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MOODY'S INVESTORS SERVICE

Credit Opinion: FortisBC Energy (Vancouver Island) Inc.

Global Credit Research - 15 Jul 2014

Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Parent: FortisBC Holdings Inc.	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa2
Parent: FortisBC Energy Inc.	
Outlook	Stable
Senior Secured -Dom Curr	A1
Senior Unsecured -Dom Curr	A3

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Key Indicators

[1]**FortisBC Energy (Vancouver Island) Inc.**

	3/31/2014(L)	12/31/2013	12/31/2012	[2]12/31/2011	12/31/2010
CFO pre-WC + Interest / Interest	**3.4x**	**3.4x**	**4.5x**	**4.4x**	**4.5x**
CFO pre-WC / Debt	**15.9%**	**14.7%**	**19.9%**	**18.0%**	**14.8%**
CFO pre-WC - Dividends / Debt	**11.6%**	**10.9%**	**18.0%**	**13.3%**	**9.7%**
Debt / Capitalization	**39.6%**	**42.2%**	**44.0%**	**48.4%**	**63.2%**

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics [2] 2011 Key Indicators reflect the company's retrospective changes due to adoption of US GAAP, effective January1, 2012

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Amalgamation credit positive for FEVI

Credit supportive regulatory environment

Stable cash flow and weak financial metrics

Transition to PBR expected to have minimal credit implications

FEVI is independent of ultimate parent, Fortis Inc

Corporate Profile

FortisBC Energy (Vancouver Island) Inc. (FEVI) is a gas LDC serving approximately 103,000 customers on Vancouver Island and the Sunshine Coast in the province of British Columbia (BC). FEVI, which has no unregulated operations, is currently regulated on a cost of service basis by the British Columbia Utilities Commission (BCUC). FEVI, with a forecasted 2014 rate base of approximately $815 million, is one of the smallest gas utilities rated by Moody's.

FEVI is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI; Baa2 stable), a holding company which also indirectly owns 100% of FortisBC Energy Inc. (FEI, A3 stable) and FortisBC Energy (Whistler) Inc. (FEW; not rated).

SUMMARY RATING RATIONALE

FEVI's credit quality is driven by its credit supportive regulatory environment and its monopoly position. The company has a track record of earning its allowed return on equity and its cash flow continues to be highly predictable. This is offset by the company's weak financial metrics, that are a product of the allowed return on equity and its equity ratio. FEVI will benefit from the increase in scale following its amalgamation with FEI, although the amalgamated entity's credit rating is expected to be FEI and FEVI's current rating, A3.

DETAILED RATING CONSIDERATIONS

AMALGAMATION CREDIT POSITIVE FOR FEVI

In February of 2014 the regulator determined that the amalgamation of FEI, FEVI and FortisBC Energy (Whistler) Inc. (FEW) is in the public interest. As a result we expect FEI, FEVI and FEW will report as a consolidated entity under the FEI name beginning Dec. 31, 2014. Current unsecured debt at FEVI will be assumed by FEI and will rank pari passu with existing FEI unsecured debt following amalgamation. FEVI and FEW are smaller utilities and they will benefit from the increase in scale that comes with the amalgamation with FEI. Their rates will decline as their higher costs are shared across a much larger customer base. Amalgamation is largely neutral to FEI as the increase in its customers' rates as a result of amalgamation are modest and will not affect its ability to recover its revenue requirement. Rate harmonization among the utilities will take place over a 3 year period. FEI's current allowed ROE of 8.75% and an equity thickness of 38.5% will apply to the consolidated entity following amalgamation.

CREDIT SUPPORTIVE REGUALTORY ENVIRONMENT

FEVI's investment grade rating is driven by its credit supportive regulatory environment and its monopoly position. Rates are typically set using a cost of service framework and a forward test year that enables the company to recover its costs and earn an allowed return established by the regulator, resulting in stable cash flow. The company has a track record of passing through its commodity costs in rates and has no direct exposure to commodity price risk and limited volume risk. To the extent that these and many other costs differ from forecast values, deferral or true up mechanisms limit exposure to forecast error. As a result the company has a long track record of earning the return on equity (ROE) established by the regulator.

For capital projects in excess of $5 million the company requires a certificate of public convenience and necessity (CPCN) that reduces the probability of cost disallowances, a credit positive. For large capital projects, the company receives a weighted average cost of capital in rates for financing costs incurred during construction; however, depreciation charges only begin once projects are complete and added to rate base. We do not believe the company has experienced any material cost disallowances. Decisions from the regulator tend to be reasonably predictable, consistent and transparent with a consultative approach. We have noted regulatory lag in some recent decisions, but the company has generally received interim rates as requested, mitigating some lag effects. Generally, when the utility or other stakeholders materially disagree with some aspects of decisions, they have been successful in asking the regulator to review and vary its decisions with final outcomes acceptable to all parties as evidenced by a lack of court challenges. The company has access to the courts to challenge regulatory decisions, although we do not believe this has happened since the utility was acquired by Fortis Inc. The legislative and judicial underpinnings of the regulatory framework continue to be stable.

STABLE CASH FLOW AND WEAK FINANCIAL METRICS

We expect the company to continue to generate stable cash flow, a key credit strength. Underpinning this stability, cash flow from operations is generally a function of the company's rate base, its deemed capital structure (41.5% equity layer effective 1/1/2013 - 12/31/2014), allowed ROE (currently 9.25%) and depreciation. We have incorporated into our analysis that the company continues to perform broadly in line with our expectations, including an assumption that the company continues to earn its allowed ROE. We expect the company's dividend policy net of any equity injections will maintain the deemed capital structure. The company is forecast to have limited financial metric headroom at the current rating. Planned large capital projects place some downward pressure on credit metrics, i.e., Tilbury LNG Expansion Project (being developed at FEI) and the pipeline to serve Woodfibre LNG because depreciation cash flow will not begin until these projects are in operation.

TRANSITION TO PBR EXPECTED TO HAVE MINIMAL CREDIT IMPLICATIONS

FortisBC utilities have submitted detailed PBR proposals for both FEI and FBC for the period 2014-2018. We have assumed that it does not represent a material change in risk and that the company continues to earn its allowed return on equity. The proposed PBR plan is broadly similar to the previous PBR plan. The proposed framework would have both an annual and mid-term review. FEI's proposal would set controllable O&M and non-CPCN (CPCN includes large capital projects that currently require regulatory pre-approval) capex by formula with substantial costs remaining as pass through items. The proposal contains a proposed symmetrical earnings sharing mechanism on up to 200bps and is subject to meeting service quality targets. Performance above or below the allowed ROE by more than 200bps would trigger an automatic review of the PBR plan. There are no proposed changes to key deferral accounts. While we don't expect it, a key risk to the proposal is that the regulator adopts very difficult efficiency targets within the formula. The PBR plan does not propose to modify support for CPCN capex. A final decision on the PBR is expected from the regulator in Q3 or Q4 2014.

FEVI IS INDEPENDENT OF ULTIMATE PARENT FORTIS INC

We consider FEVI to be operationally and financially independent of ultimate parent Fortis Inc, although the company may periodically rely on its parent for equity injections to maintain its capital structure in line with the regulator's established parameters. Rate base of FortisBC' companies accounts for over 45% of FTS's total rate base, although this will decline with Fortis Inc's planned acquisition of UNS Energy Corporation, expected to close at the end of 2014. We expect that Fortis Inc. would provide extraordinary support to FEVI if required, provided that the parent had the economic incentive to do so. We believe that the parent will continue to have sufficient resources to provide support, if required. At March 31, 2014, FTS had a $1 billion committed revolving corporate facility at the FTS corporate level, of which $824 million was unused. Ring fencing provisions at FEVI limit the ability of Fortis Inc to upstream cash, although we do not believe the parent would seek to increase leverage above levels established by the regulator.

Liquidity Profile

FEVI has adequate liquidity.

For LTM 1Q14, FEVI has free cash flow of $14 million calculated using $61 million CFO net of $16 million dividends and $31 million capex. However, we expect negative free cash flow in the range of $20-40 million in 2014 due to the start of Revenue Surplus Deferral Account (RSDA) drawdown and construction of the pipeline to serve the Woodfibre LNG project. The Woodfibre project is expected to built over the period from 2014 to 2016 with an in-service estimate of Q4 2016 and the majority of spending planned in the final year of construction. FEVI is expected to manage dividend payouts and parent equity injections to keep its equity layer close to the approved level of 41.5% along with its capex spending and borrowing profile. We expect FEVI to rely on its credit facility for the pre-amalgamation construction phase of Woodfibre and to receive support from the amalgamated FEI when it raises additional debt post 2015.

At the end of Q1 2014, FEVI's $200 million credit facility was undrawn and is expected to serve as a main cash source to cover the negative free cash flows. We expect the company to extend this facility prior to its maturity on December 31, 2015. The facility contains a single maintenance covenant (debt to equity not greater than 70%). As at March 31, 2014, FEVI had reasonable headroom under the covenant. FEVI's credit agreement does not contain language such as a Material Adverse Change (MAC) clause or ratings triggers that would inhibit access to the unutilized portion of the facility in situations of financial stress.

FEVI has no near term debt maturity. The next maturity of $250 million Series 2008 debenture is in February 2038.

Rating Outlook

The stable outlook is based on our expectation of a stable regulatory environment and stable, albeit weak financial metrics with ongoing limited headroom at the current rating level.

What Could Change the Rating - Up

Given the ongoing forecast weakness in credit metrics an upgrade is unlikely. We could upgrade the company with a material sustained improvement in financial metrics, including CFO pre W/C to debt in the mid to high teens.

What Could Change the Rating - Down

While we don't expect it several factors could lead to a downgrade. For example, an unexpected, material adverse regulatory decision or forecast sustained deterioration in credit metrics including CFO/pre-W/C to debt of less than 11%.

Rating Factors

FortisBC Energy (Vancouver Island) Inc.

Regulated Electric and Gas Utilities Industry Grid [1][2]	**Current LTM 3/31/2014**		[3][4]**Moody's 12-18 Month Forward ViewAs of June 2014**	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.0x	Baa	2.4 - 2.8x	Ba
b) CFO pre-WC / Debt (3 Year Avg)	18.1%	Baa	11 - 14%	Baa
c) CFO pre-WC - Dividends / Debt (3 Year Avg)	13.3%	Baa	6 - 9%	Ba
d) Debt / Capitalization (3 Year Avg)	42.4%	A	45 - 48%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		A2		A3
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. [2] As of 3/31/2014(L); Source: Moody's Financial Metrics [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. [4] Moody's forward view is based on FEI's post-amalgamation financial projections

FORTISBC ENERGY INC.

Amalgamated Cost of Capital for 2016

Appendix X

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1. INTRODUCTION

The assessment of a utility's risk profile is an essential element of its cost of capital estimation process. The FortisBC Utilities (FBCU) provided a detailed description of FEI's business risk profile as Appendix H of its evidence in the Generic Cost of Capital Proceeding – Stage 1 (GCOC Stage 1). Further, a comparison of FEI's business risk profile with that of FEVI and FEW was provided as Appendix A of its evidence in the Generic Cost of Capital Proceeding – Stage 2 (GCOC Stage 2). The Companies described their overall competitive, operating, policy and regulatory environment using specific categories of business risk and risk factors.

Since the filing of evidence in GCOC Stage 1 and GCOC Stage 2, on February 26, 2014 by Order G-21-14, the Commission approved the amalgamation of FEI, FEVI and FEW. On May 23, 2014, the Lieutenant Governor in Council issued Order in Council No. 300 consenting to the amalgamation. The amalgamated entity is carrying on business as FEI, and in this proceeding will be referred to as "the amalgamated FEI" or "FEI Amalco".

This Appendix describes amalgamated FEI's overall competitive, operating, policy and regulatory environment using the same categories of business risk and risk factors that had been used in the Companies' GCOC filings. FEI assesses any changes to its risk profile from two perspectives:

1. FEI has assessed how its risk profile has changed in comparison to risks defined in GCOC Stage 1 as a result of factors other than the amalgamation itself. The analysis addresses, for instance, changes in commodity prices or regulatory and political developments since 2012.

2. FEI has also considered the extent to which FEI's risk profile has changed as a result of amalgamating with FEVI and FEW. In GCOC Stage 2, the FBCU stated that FEVI's and FEW's risk profiles were higher than that of FEI due primarily to (a) greater concentration of assets within a small service area, (b) less diverse customer and economic base, (c) greater challenge in terms of price competitiveness and (d) greater supply security risk due to regional infrastructure constraints and dependency on a single pipeline system that traverses challenging terrain. Amalgamation has addressed items (a), (b) and (c), for the most part[1]; however, item (d) represents an incremental risk for the amalgamated FEI in comparison with GCOC Stage 1. In addition, the effect of amalgamation on other elements of FEI's business risks will be studied in this section.

Amalgamated FEI's overall business risk is best characterized as being similar to that of the 2012 benchmark utility (pre-amalgamation FEI) and trending slightly higher.

[1] Until January 1st 2018 when the phase-in period will be completed, the Vancouver Island and Whistler service areas continue to have higher delivery rates than the Mainland.

2. OVERVIEW OF BUSINESS RISK

2.1 Generic Business Risk Categories and Factors

In the GCOC Application, FEI identified eight different business risk categories, as presented in Table 1 below. FEVI and FEW used the same categories in Stage 2 of the GCOC proceeding. Other risk factors and categorizations are possible, and some risk factors could be captured under a different risk category.[2] However, using the same categories as in the GCOC proceeding facilitates the comparison of the amalgamated FEI risk profile with business risk information presented during the GCOC proceeding.

Table 1: Business Risk Categories and Risk Factors Addressed in this Appendix

Business Risk Category	Risk Factors
Business Profile	• Type and size of utility • Energy product offering • Service area and 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 capture rates
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 uncertainty and lag • Deferral accounts • Administrative penalties

[2] For example, availability of energy supply could also be included as a risk factor under Energy Prices because the availability of supply of an energy form can impact its price.

2.2 Summary Assessment of Amalgamated FEI's Business Risk

Table 2 ranks the business risk categories as they apply to the amalgamated FEI and by providing a summary assessment of whether the risks to amalgamated FEI associated with particular risk factors is higher/lower/same as it was for the benchmark utility (FEI prior to amalgamation). The ranking of the risk categories provided below is identical to what was provided in GCOC Stage 1, with regulatory risk being the highest risk, followed by the risk categories most directly influencing throughput, and then other risk categories relating to operations and supply.

Table 2: Amalgamated FEI's Business Risk as Compared to 2012 Benchmark Utility

Business Risk Category	Risk Factor	Total Risk status since 2012, (all business changes incl. amalg.)	Risk status change due to amalgamation alone	Ranking of risk
Regulatory		**Same**		**1**
	Regulatory uncertainty and lag	Same	Same	
	Deferral accounting	Same	Same	
	Administrative penalties	Same	Same	
Energy Prices		**Same**		**2**
	Commodity prices	Same	Same	
	Commodity price volatility	Higher	Same	
	Upfront and installation cost	Same	Same	
Market Shifts		**Same**		**2**
	New technology and Energy forms	Same	Same	
	Perception of energy	Same	Same	
	Housing types	Same	Same	
	Changes in energy use	Same	Same	
	Changes in the capture rates	Same	Same	
Political		**Higher**		**2**
	Energy policy and legislation	Same	Same	
	GHG emissions reductions	Same	Same	
	Carbon tax	Same	Same	
	Aboriginal rights	Higher	Same	
Business Profile		**Same**		**2**
	Type and size of the utility	Same	Same	
	Energy product offering	Same	Same	
	Service area and customer profile	Same	Same	
Economic Conditions		**Same**		**2**
	Overall economic conditions	Same	Same	
Operating		**Same**		**3**
	Infrastructure integrity	Same	Same	
	Third party damages	Same	Same	
	Unexpected events	Same	Same	

Business Risk Category	Risk Factor	Total Risk status since 2012, (all business changes incl. amalg.)	Risk status change due to amalgamation alone	Ranking of risk
Energy Supply		**Higher**		**4**
	Availability of supply	Same	Same	
	Security of supply	Higher	Higher	

The key points from this "snapshot" regarding the relative risk of amalgamated FEI compared to 2012, which are discussed throughout this Appendix, are:

- The Commission's jurisdiction is confined to what is conferred by the *UCA,* but within that framework has significant discretion in the exercise of those powers. FEI is dependent on regulatory approvals of rates that determine its revenues. The Commission establishes the level of return that is allowed to be included in rates, and establishes depreciation rates that determine a utility's ability to recover invested capital. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty which in itself gives rise to the risk that the allowed return does not accord with the fair return standard, that rates are set at a level that does not provide FEI with an opportunity to earn its fair return, or that necessary investments are not approved. Compared to previous periods, the 2014 PBR Decision included some additional regulatory uncertainty and risk, although the broader regulatory constructs that supported FEI's characterization of regulatory risk in 2012 remain in place. FEI has thus assessed its overall regulatory risk as being similar to what it was in 2012, with the potential to be higher over the term of PBR.

- Natural gas prices increased at the end of 2013 and the beginning of 2014 before coming down in early 2015. Furthermore, natural gas prices have continued to remain volatile - for example, significant price spikes occurred during winter 2013/14 due to North America experiencing one of the coldest winters in decades. On the other hand, electricity prices have increased which has improved the current price competitiveness of natural gas versus electricity. However, the more favourable price competitiveness of natural gas compared to electricity is being muted by other non-price factors. All things considered, FEI assesses that the risks associated with energy price as similar to that of its 2012 assessment levels.

- The market shift in energy demand caused by the continued support for the new energy forms and technologies that produce energy closer to the point of consumption, along with rate of change in housing mix and customer perception of energy, all continue to represent challenges to retaining and attracting customers even in the current lower energy price environment. Similar to 2012, the declining trend in FEI's throughput level, particularly for residential sector can be explained in twofold: (a) weak capture rates in new construction market in the growing multi-family dwelling sector and (b) declining use per customer from existing and new customers caused by smaller average dwelling size as well as improvements in energy efficiency and conservation efforts supported by the provincial and local governments' policies.

- Government policies and regulations have a significant impact on FEI's operations and competitiveness. The overall thrust of the climate change and energy policies remains similar to that articulated in 2012. With the passage of time, these policies have been implemented to a greater extent. Similar to 2012 provincial government's policies continue to discourage the use of natural gas in FEI's traditional markets of space heating and water heating while promoting the role of natural gas in transportation sector and LNG export. Further local governments and municipalities have intensified their "green initiatives" and in some instances have introduced updates to their bylaws and codes that can substantially hinder FEI's ability to attract new customers and/or retain existing ones. On the subject of Aboriginal rights and title issues, the recent Supreme Court of Canada Decision in *Tsilhqot'in Nation v. British Columbia* introduced new uncertainties and emboldened Aboriginal groups. Overall, political risk is assessed as similar to 2012 and continuing to trend higher.

- The amalgamated FEI has a larger customer base and service territory than the 2012 benchmark utility. The business profile of the amalgamated entity is not materially different from FEI's pre-amalgamated business risk profile level. This viewpoint has been confirmed by credit agencies such as DBRS[3].

- The current Canadian economic environment continues to be dominated by uncertainty. A combination of factors from the recent drop in oil prices and a slow-down in economic growth in Europe and China to weaker Canadian dollar and a strong U.S. recovery lead to the assessment that the overall economic condition is not materially different from 2012 levels.

- Operating risk factors include infrastructure integrity, third party damages and unexpected events. All things considered, the overall operating risk is assessed to be similar to 2012.

- Despite the abundance of supply associated with the development of tight and shale gas resources, the underlying infrastructure to move this natural gas to FEI's service territory (accessibility of supply) remains unchanged as compared to 2012. The development of several significant gas transmission infrastructure projects connecting BC deposits with Alberta and eastern markets in the coming

[3] Please refer to DBRS's January 2015 FEI's rating report.

years could alter the amount of gas available to FEI and the historical pricing relationship of BC supply in relation to Alberta production. This could have a negative impact to the price that consumers pay for natural gas in BC in the coming years. The addition of FEVI and FEW to amalgamated FEI's service territory has slightly increased FEI's exposure to security of supply risk. As such, the overall risk is considered to be slightly higher than 2012 levels.

Considered together, amalgamated FEI's overall business risk is best characterized as being similar to that of the 2012 benchmark utility (non-amalgamated FEI) and trending slightly higher.

3. BUSINESS PROFILE

As business risk is specific to a particular utility, it is important to understand the fundamental characteristics (or business profile) of the utility being assessed. Discussed below is a high level overview of amalgamated FEI's business profile.

In 2012, the benchmark utility FEI was a large natural gas distribution utility whose core business was serving space and water heating load in the residential and commercial sectors. FEI also served industrial load. The core market was experiencing declining throughput levels and slow customer growth, while facing continued competitive challenges, which were central to its overall business risk.

Following the amalgamation of FEI, FEVI and FEW on December 31, 2014, the amalgamated FEI remains a large natural gas distribution utility. Its operations now extend to three service areas of the Mainland, Vancouver Island and Whistler, serving approximately 975,000 customers throughout the province. However, its core business remains serving space and water heating load in the residential and commercial sectors. As before, the core market is experiencing declining throughput levels and slow customer growth, while facing continued competitive challenges, which are central to its overall business risk.

For comparability and presentation purposes, the FEI amounts shown for the years prior to 2015 have been restated to include FEVI and FEW, unless otherwise noted.

Table 3 summarizes FEI Amalco's overall business profile.

Table 3: Amalgamated FEI's Business Profile

Type of Utility	Local Distribution Company
Energy Product Offering	Natural gas, biomethane, propane[4]
Service Area	Mainland, Vancouver Island and Whistler
Rate Base*	$ 3,656 (millions)
Sales/Transportation Volumes*	174,623 (TJs)
Number of Customers*	975,000
Customer Additions*	12,968
Customer Growth Rate*	>1%
Customer Profile by Demand*	
Residential	39%
Commercial	29%
Industrial	32%
Customer Profile by Sales Revenue*	
Residential	60%
Commercial	33%
Industrial	7.0%

* Based on 2015 Annual Review.
- Residential includes Rate Schedule 1. Commercial includes Rate Schedules 2, 3, 23.
- Industrial includes Rate Schedules 4, 5, 6, 7, 22, 25, 27 (does not include by-pass customers such as Burrard Thermal)
- Bypass Transportation volumes is around 31,352 TJs.

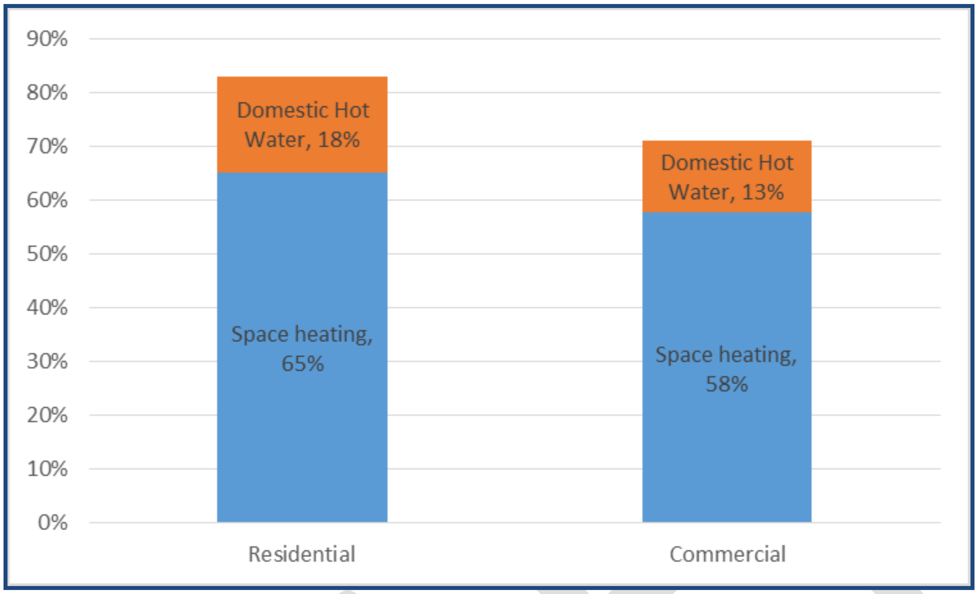
The fact that the majority of FEI's delivery margin revenue is generated from residential customers (i.e. Rate Schedule 1) is significant because FEI faces its greatest challenges[5] in the residential market.

Figure 1 below demonstrates that in FEI's residential and commercial sectors, space and water heating are the dominant end uses, accounting for about 83 percent and 71 percent of the energy consumption respectively for each sector. The most recent information is from 2011 and consolidated information for FEI, FEVI and FEW (collectively, the "FEU") has been presented (as opposed to FEI separately) to provide a better indication of FEI Amalco's profile today.

[4] FEI also serves propane customers in Revelstoke. FEI has a relatively new biomethane offering that is a notional mix of natural gas and 10% biomethane.

[5] For instance the impact of the provincial and local governments' policies on the gradual decline of the natural gas share in the water and space heating markets is more pronounced for residential sector.

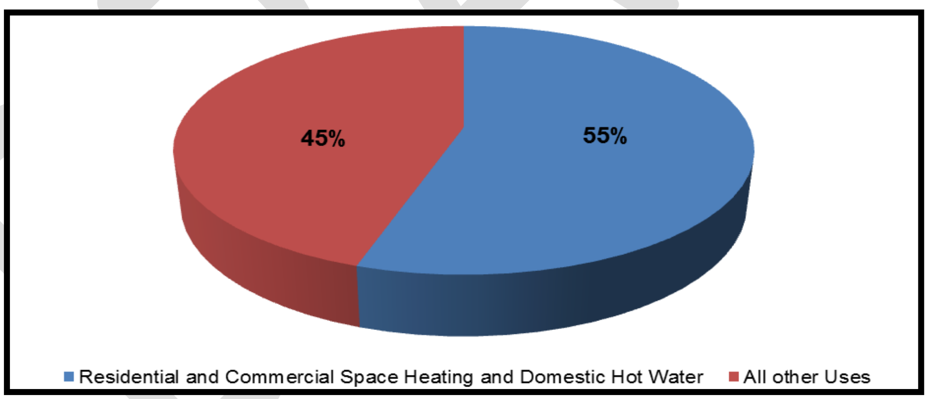
Figure 1: Residential and Commercial Consumption by End Use (2011 – Consolidated FEU Data)



Source: 2014 LTRP Scenario zero

Thus, the space and water heating market in residential and commercial applications is FEI Amalco's largest market for natural gas, as shown in Figure 2 below.

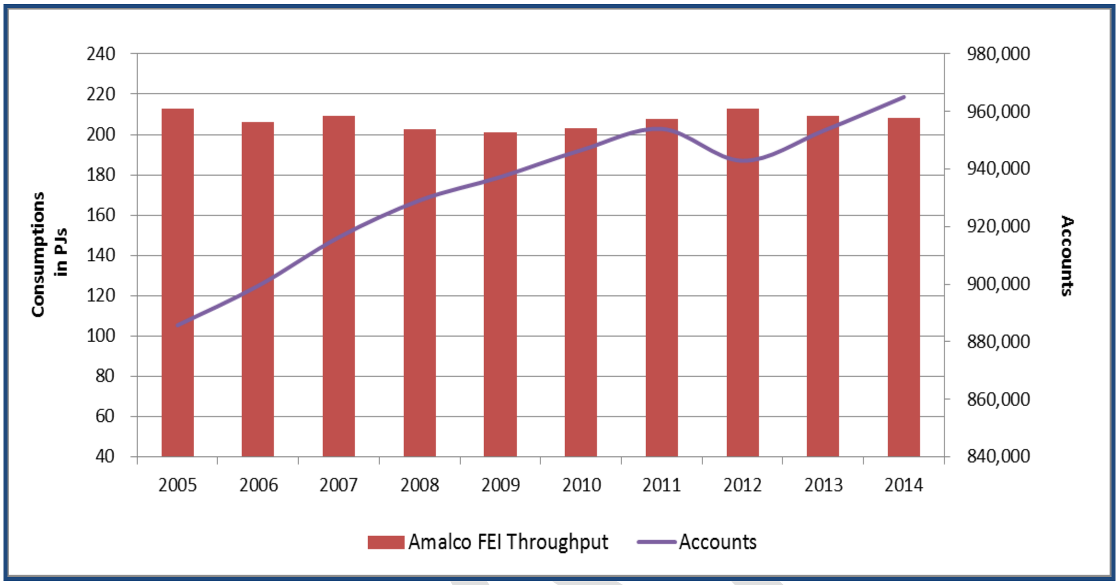
Figure 2: Total Consumption by End Use (2011 – Consolidated FEI, FEVI and FEW Data)



Source: 2014 LTRP Scenario zero

As demonstrated in Figure 3, despite adding a modest number of residential customers in recent years, the FEU/amalgamated FEI's total throughput has remained almost the same as in 2005. Indeed, in 2014, amalgamated FEI's normalized demand has experienced a modest decrease compared to the 2012 levels. Industrial throughput variations are one of the large contributors to the annual variations in total normalized throughput. This arises from industrial customers' price sensitivity and the effects of business cycles as well as continuing efforts by industrial customers to improve the energy efficiency of their operations[6]. In the long-run the direction of industrial demand will be dependent on competitiveness of natural gas to alternatives for each industrial customer and the economic conditions of specific industries.

Figure 3: Amalgamated FEI/FEU's Total Throughput (Normalized Demand vs. Customer Accounts)

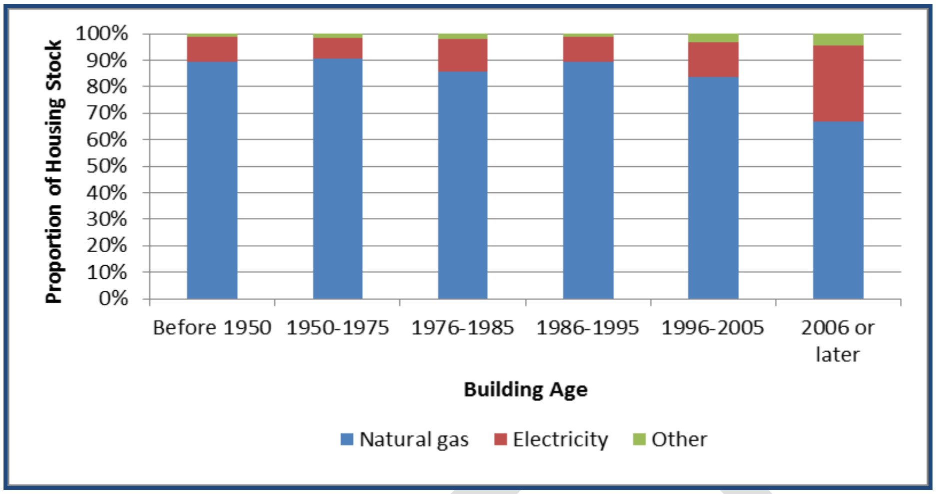


The use of natural gas as a main space heating fuel is diminishing while the use of electricity as a main heating fuel is on the increase. According to the 2012 Residential New Home Survey (RNHS), new homes with gas service are less likely to use natural gas as a main space heating fuel and more likely to use electricity when compared to the stock of gas homes built prior to 2006. Figure 4 below illustrates the main space heating fuel trend by dwelling age.

---

6 BC's cement industry illustrates these factors. Cement manufacturers exhibit positive cross-price elasticity of demand between natural gas and coal, meaning if the price of natural gas goes up, the demand for coal will increase. For instance a major cement manufacturer in Delta, BC, decreased its consumption from 1.719 PJs in 2012 to only 0.244 PJ in 2014 partly due to the increase in natural gas prices between 2012 and 2014. Canadian cement manufacturers are signatories to the Cement Sustainability Initiative of the World Business Council for Sustainable Development, which aims at curbing carbon emissions from its existing production and companies, are increasing their use of alternative fuels to hit the BC's goal of 40 per cent alternative fuels (non-fossil fuels).

Figure 4: Natural Gas Use for Residential Space Heating

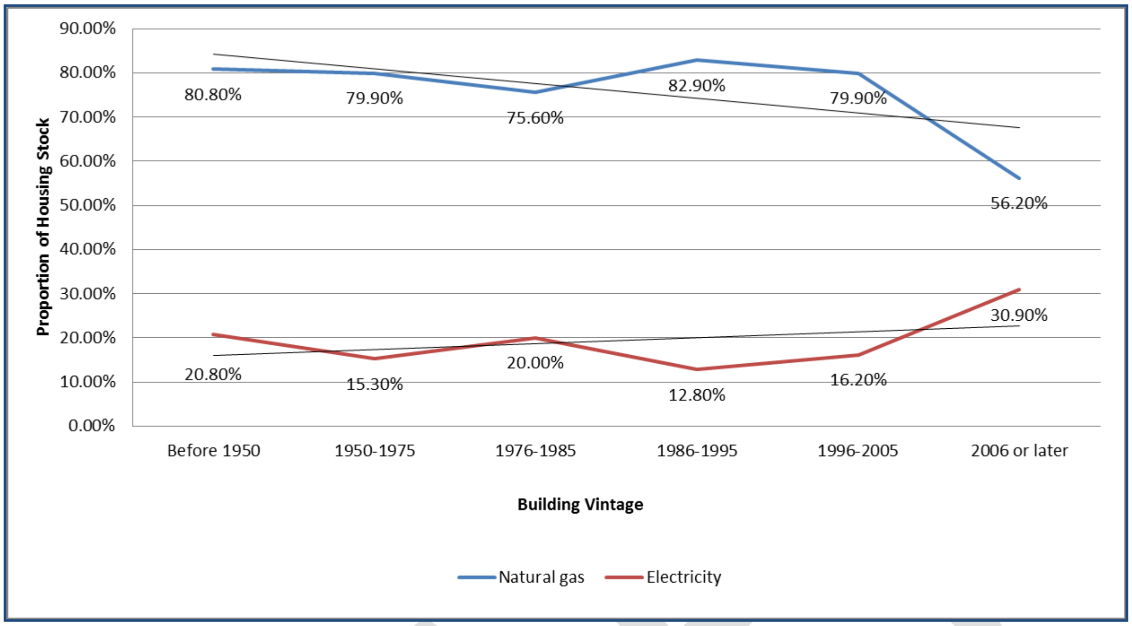


Source: 2012 Residential New Home Survey

The above trend regarding the energy source used for space heating in housing stock of newer vintages is significant because the share of natural gas heated homes with respect to homes built since 2005 has eroded in light of increasing use of other energy forms, primarily electricity. In comparison with the 2010 RNHS, the percentage of new homes using electricity for space heating in the surveyed population has increased which is consistent with FEI's conclusions in the market shift risk section, that is FEI continues to lose market share to electricity in the space heating sector. The increasing share of electricity use in space heating is also validated by BC Hydro's 2012 residential end-use study.

The same trend is occurring for Domestic Water Heating (DWH), which constitutes the second largest share of natural gas use for residential customers (accounting for 18 percent of total residential natural gas use). According to the 2012 RNHS, new homes with gas service are less likely to use natural gas fired DWH and more likely to use electricity compared to the stock of homes built prior to 2006. Figure 5 below illustrates the trend in DWH fuel by dwelling age. Natural gas use for domestic water heating in new homes has continued to decrease compared to the 2010 RNHS which demonstrates FEI's continuing challenges in capturing new customers in this sector.

Figure 5: Trend in Residential Domestic Water Heating Fuel by Dwelling Vintage

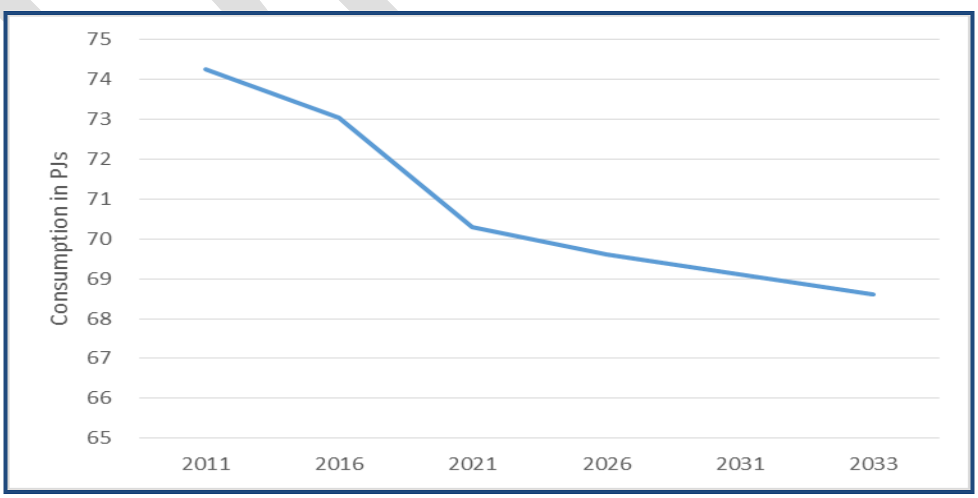


Note: Numbers not additive because some homes may have more than one DWH fuel. Don't knows (DKs) and no responses (NR) are excluded.

The underlying reasons for the declining trend in natural gas use in residential water and space heating sectors will be further explained in market shift risk and political risk sections of this appendix.

As space heating and domestic hot water heating together account for over 80 percent of total residential natural gas consumption, the declining trends discussed above will negatively impact throughput and load growth. Figure 6 shows the most likely scenario for throughput levels in the residential sector in the years to come.

Figure 6: Outlook of FEU/Amalgamated FEI Residential Throughput Levels



Source: 2014 LTRP – Residential Sector, Scenario Zero

FEI has, in recent years, responded to the changing energy environment in BC and declining throughput in its core business by undertaking new initiatives. One of those initiatives, Natural Gas for Transportation (NGT), has been identified as a potential new source of load outside of FEI's core market. Table 4 provides an estimate of the additional volumes forecast to be added to the system as a result of Greenhouse Gas Reduction (Clean Energy) Regulation incentive funding and overall efforts to add NGT load to the system.

Table 4: FEI's NGT Demand Forecast (2015-2019)

FEI					
Consumption (GJ)	**2015F**	**2016F**	**2017F**	**2018F**	**2019F**
Trucks/Buses (CNG)	401,500	572,500	772,500	1,022,500	1,272,500
Trucks (LNG)	482,844	595,344	820,344	1,045,344	1,270,344
Marine (LNG)	0	2,166,640	4,099,315	4,277,065	704,168
Mine Haul Trucks (LNG)	0	75,000	2,398,780	3,120,750	3,900,025
Rail (LNG)	0	0	365,000	912,500	1,277,500
Total Demand (CNG/LNG)	**884,344**	**3,409,484**	**8,455,939**	**10,378,159**	**8,424,537**

A continuation of the current low oil prices may hinder FEI's efforts to expand the NGT demand in its service territory.

NGT volumes are a favourable development for customers in terms of representing a revenue stream. However, they do not materially affect FEI's overall risk profile. For instance, FEI's NGT demand for 2015 is forecast to be around 0.884 PJ which represents less than 1 percent of amalgamated FEI's total throughput. Even if NGT expands to its potential over the next 5 years, its share of total throughput would remain relatively small.

In addition to the NGT initiative, FEI is also exploring the possibilities of expanding its LNG business for regional export markets, remote communities and power generation. The potential load for these initiatives can reach to more than 6.5 PJs by the year 2019[7] which amount to less than 4 percent of amalgamated FEI's current total throughput.

Along with the above mentioned initiatives, FEI has also been active in advocating for establishment of appropriate frameworks for addition of potentially large new industrial loads from the Tilbury phase 1B expansion project and Woodfibre project for LNG export. The amendments to the Direction No.5 provided some clarity regarding the rates and tariffs for these potential large industrial clients. Nevertheless, there is still uncertainty as to whether some of the proposed projects will proceed. FEI expects that

[7] The incremental LNG load for both NGT-related and other LNG demand will be supplied from the Tilbury phase 1A expansion project which will add an additional 1.1 PJ of LNG storage and about 34,000 GJ per day of liquefaction capacity. The Tilbury phase 1A expansion is expected to be operational in the fourth quarter of 2016. For more information regarding the Tilbury expansion project please refer to the political risk section.

these new initiatives and the investment in new infrastructure to serve them would bring some benefits to existing customers.

In summary, FEI's current core business continues to be in the natural gas distribution for space and water heating and will remain so for the foreseeable future even with additions of forecasted NGT and other LNG load that may occur. Attracting and retaining customers in the traditional heating markets remain a critical undertaking, and a key challenge, for FEI

4. ECONOMIC CONDITIONS

Economic conditions can impact the ability of utilities like FEI to attach new customers and retain customers or maintain throughput levels, in addition to affecting utility access to capital in the manner discussed in Appendix --. The current Canadian economic environment continues to be dominated by uncertainty. The recent drop in global oil prices will negatively impact GDP growth in oil-producing regions. Other provinces will likely feel some indirect impacts of lower oil prices through reduced trade with the oil-producing provinces. Further, economic and financial conditions external to both Canada and BC (i.e. slowdown in economic growth in China, potential re-emergence of Eurozone crisis) have the potential to impact Canada's and BC's economic outlook. Nevertheless, the weaker Canadian dollar and a strong U.S. recovery have the potential to improve export opportunities and partially mitigate some of these challenges. Therefore, compared to 2012, FEI assesses the risk related to economic conditions as unchanged.

Table 5 summarizes the changes in leading economic indicators for four jurisdictions across Canada.

Table 5: Economic Indicators for Four Jurisdictions in Canada (2012 to 2016)

	2012	2013	2014	2015	2016
British Columbia					
Real GDP (% change)	2.4	1.9	2.4	2.7	2.4
Unemployment (%)	6.7	6.6	6.0	5.8	5.8
Housing starts (% change)	4.4	-1.5	4.6	-6.0	-2.6
Alberta					
Real GDP (% change)	4.5	3.8	3.8	0.5	1.8
Unemployment (%)	4.6	4.6	4.6	5.3	5.6
Housing starts (% change)	30.4	8.2	12.6	-17.4	-3.6
Ontario					
Real GDP (% change)	1.7	1.3	2.3	2.8	2.5
Unemployment (%)	7.8	7.5	7.3	6.9	6.8
Housing starts (% change)	14.1	-21.4	-4.0	-1.8	-0.2
Quebec					
Real GDP (% change)	1.5	1.0	1.8	2.2	2.0
Unemployment (%)	7.8	7.6	7.7	7.6	7.5
Housing starts (% change)	-2.4	-20.3	3.8	-3.5	1.2

Shaded area represents forecast data.
TD Economics, January 2015, retrieved from:
http://www.td.com/document/PDF/economics/qef/ProvincialEconomicUpdate_Jan2015.pdf

Focusing on BC, the real GDP gains in BC are forecast to remain close to the 2012 level. Further, compared to 2012, BC's unemployment rate has slightly improved and is projected to be around the six percent mark.

Housing starts are an important variable in determining residential customer additions. As seen in Table 5, BC is expected to be faced with a continued period of lower housing starts with a forecast of a close to 6.0 percent decline in housing starts in 2015. Lower projected housing starts can be expected to make it more difficult for FEI to add new customers and throughput.

5. ENERGY PRICE RISK

Energy prices impact utility business risk because price is among the factors that can influence consumer energy choices. Electricity remains the primary alternative available in British Columbia for space and water heating.[8] There are a number of factors that

[8] In this document, the references to electricity as an energy source in British Columbia mainly relate to BC Hydro, which delivers nearly 95 percent of electricity within the province.

impact the price competitiveness of natural gas in BC relative to electricity.[9] They include:

- natural gas commodity cost relative to electricity;
- natural gas price volatility; and
- relative installation costs of gas appliances compared to electric appliances.[10]

While energy price remains a driver of business risk recent experience suggests that other non-price considerations such as GHG emissions, type of housing mix and the size of new dwellings, customer perceptions and government policy (discussed in subsequent sections) are taking on greater importance in the decisions of energy consumers.

FEI's assessment is that compared to 2012, the commodity price risk has remained relatively unchanged. Further, the price volatility risk is higher than the level assessed by the Commission in 2012 and the risk associated with upfront and installation cost is considered to be similar. Amalgamation had no material impact on energy price risks.

5.1 Commodity Price

This section addresses the commodity price of natural gas versus electricity and how it affects FEI's competitive position. While natural gas commodity prices are set by the market, electricity prices are heavily influenced by BC Hydro's low embedded costs, making it more difficult for FEI to compete against electricity than gas utilities in some other provinces. Natural gas competitiveness in BC is further challenged by the implementation of the BC carbon tax as well as other non-price factors.

Natural Gas Commodity Prices

In general, commodity rates in the natural gas utility sector reflect the utility's cost of purchasing the gas on behalf of its customers, without mark-up. Natural gas prices are set in an open and competitive market and are influenced by many variables throughout North America, as well as each utility's operating region. Commodity rates will therefore fluctuate in response to changes in supply and demand conditions for natural gas.

The North American natural gas market has undergone significant changes during the past few years in terms of supply, demand, and pricing. Continued advances in drilling technology associated with shale gas and the upsurge in associated natural gas supply from increased oil production in the past few years have led to an abundance of gas

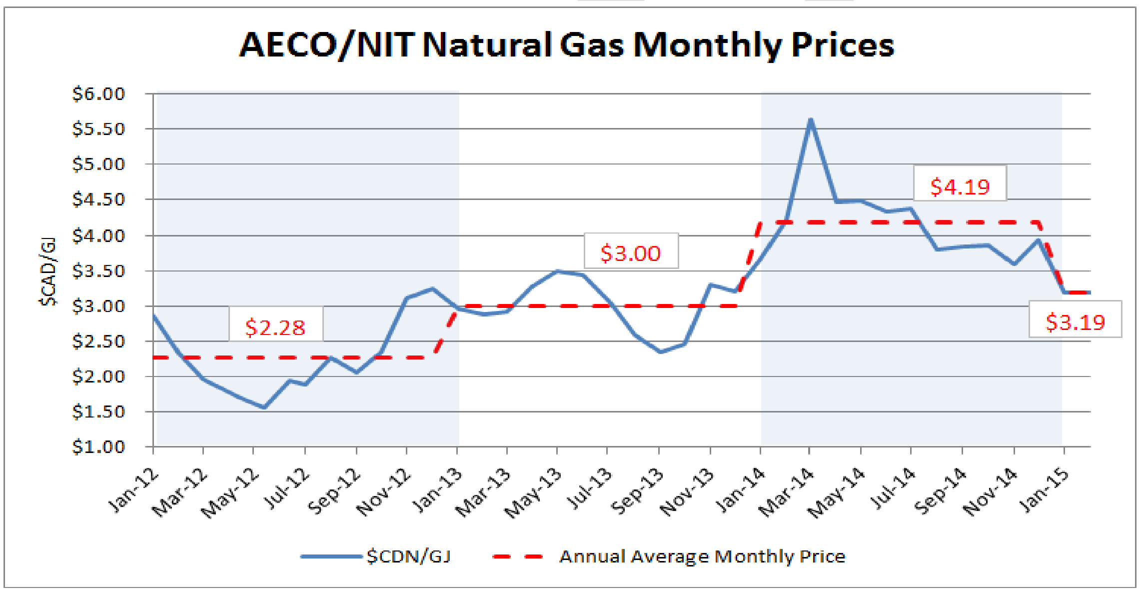
[9] This was recognized by the Commission in its 2009 ROE and Capital Structure Decision, page 36, where the Commission stated: "…natural gas' competitive edge over electricity is dependent on too many significant variables, such as the level of the carbon tax, the volatility of natural gas prices and the impact of government policy on BC Hydro's rates, to be considered permanent".

[10] Builders and developers surveyed in the 2010 RNHS study have attributed the decline of gas water heating to regulation (i.e. changes in building codes) for gas furnaces such as the requirement to install more costly high efficiency units.

supply, resulting in an oversupplied natural gas market. However, despite this, with the cold winter of 2013/14 North America gas storage inventory levels dropped to their lowest levels in a decade. The combination of high 2013/14 winter demand and low storage inventory levels during the first half of 2014 provided support for higher gas prices throughout 2014. Strong gas production growth and mild summer and fall weather in 2014 enabled gas storage balances to recover going into winter 2014/15. With a more normal winter for 2014/15, in 2015, natural gas prices have softened following continuing strong production growth and healthy storage inventory builds.

Figure 7 below illustrates the AECO/NIT[11] monthly prices from January 2012 to January 2015. As illustrated, the annual average monthly price has increased to $4.19 CAD/GJ in 2014 (from $2.28 CAD/GJ in 2012) and recently dropped to $3.19 CAD/GJ in January 2015.

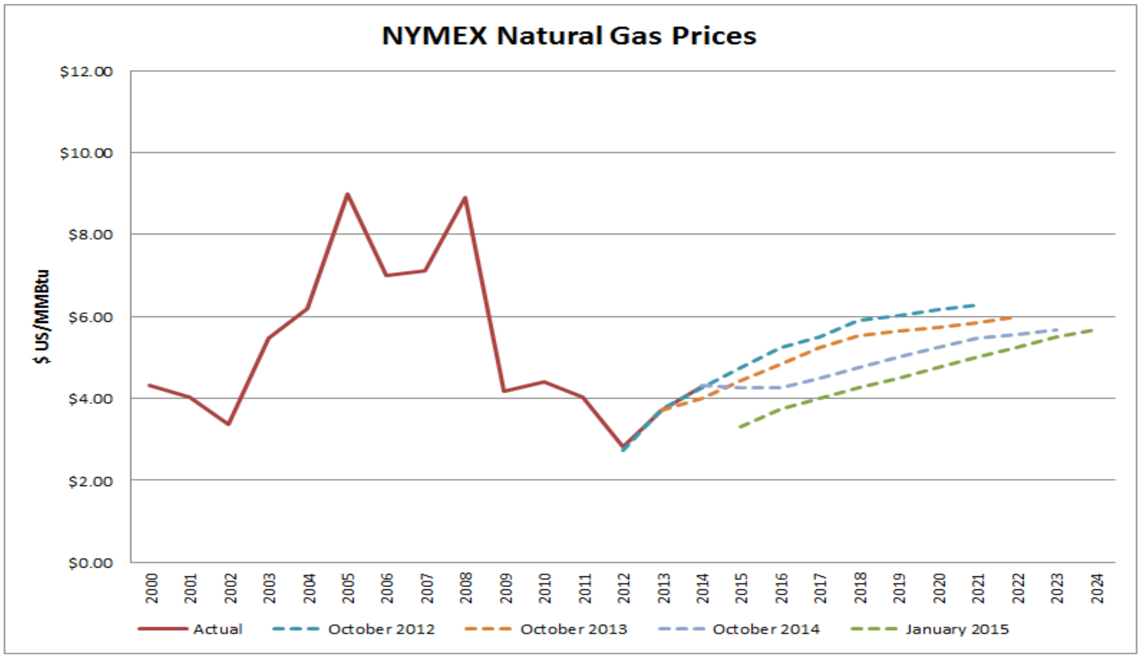
Figure 7: AECO/NIT Natural Gas Monthly Prices January 2012 to January 2015



U.S. dry gas production has increased significantly since 2012 and reached a record high of 73.6 Bcf/d in December 2014 (compared to an average of 66.0 Bcf/d in December 2012). With supply continuing to outpace demand, current market price forecasts, while still predicting higher prices in the future, are at a lower starting point compared to the 2012 outlooks, as illustrated in the following figure.

[11] AECO/NIT (NOVA Inventory Transfer) is one of the largest natural gas trading hubs in North America, located in Alberta.

Figure 8: Comparison of Natural Gas Price Forecasts[12]



Source: GLJ Petroleum Consultants

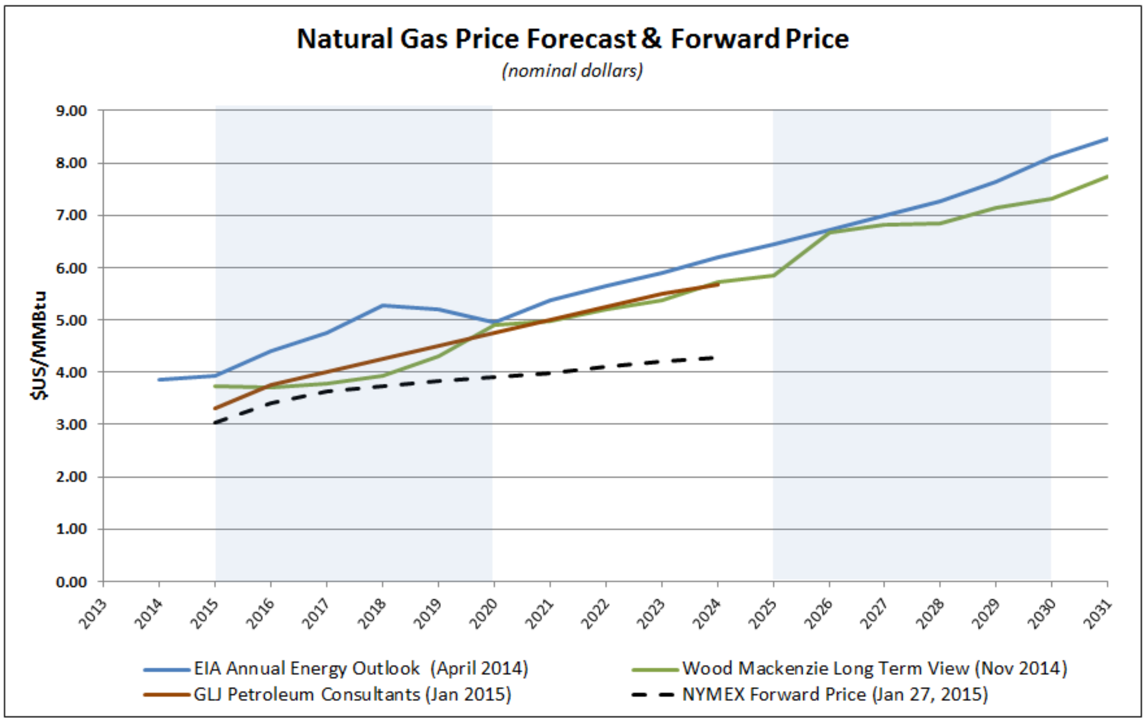
The continued lower level of natural gas prices in recent years has provided incentives and opportunities for the greater use of natural gas across North America. Demand is recovering in the industrial sector after being depressed from the recession which started in 2008. Additionally, new electricity load powered by natural gas and greater switching from existing coal-fired power plants to natural gas and combined cycle power plants contribute to the increased demand. Increasing exports of U.S. gas to Mexico, as well as the development of emerging markets such as liquefied natural gas (LNG) exports and natural gas for transportation (NGT) will add to demand over the long run.

As a result, all forecasts show gas prices over the long run following an upward trend due to a re-balancing of supply and demand. As the current pricing environment does not provide a strong positive return for producers to invest in new capital, some producers have been cutting their capital spending in 2015. A slowdown in the growth of production due to the low market price environment will also help to rebalance the market combined with increased demand should help to rebalance the market place. Natural gas demand is expected to increase in the long-run and higher prices are required to bring incremental supply online to satisfy this demand. It remains to be seen, with the recent sudden drop in crude oil prices, if oil producers will cut back on oil production in the coming months or years and if there will be any impact on the associated gas that is produced with oil production. If oil and associated gas production is reduced, this could lead to higher natural gas prices.

[12] NYMEX - The New York Mercantile Exchange is a commodity futures exchange. The NYMEX nature gas price is based on Henry Hub, a distribution hub in Louisiana, and is used as the primary reference price for the North American natural gas market.

Figure 9 below illustrates various long-term price forecasts for Henry Hub natural gas (in nominal prices), compared to the current NYMEX Henry Hub forward price curve as of January 2015. The NYMEX forward price curve reflects current market transactions from buyers and sellers for future delivery, whereas the long term forecasts are more reflective of the long-term natural gas supply and demand fundamentals. The long term forecasts indicated that by 2020, gas prices could be about $5.00 US/MMBtu. By 2025, analysts forecast that gas prices could be about $6.00 US/MMBtu.

Figure 9: Long-Term NYMEX Natural Gas Price Forecasts and the Forward Market Price Curve



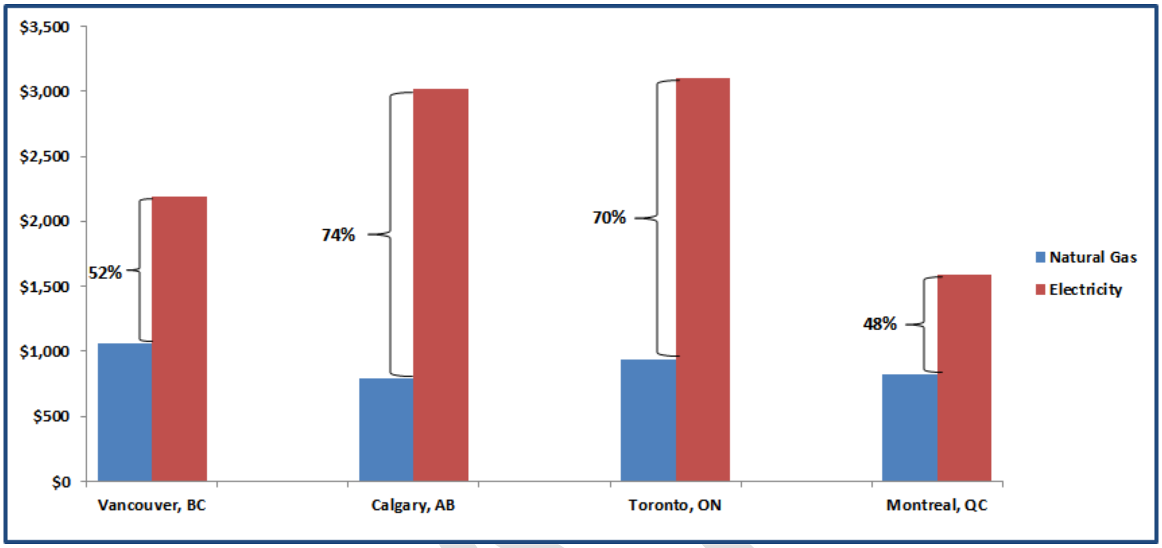
Given the combined factors of higher natural gas spot prices with the downward shift of forward prices now compared to 2012, and a continued upward trend of long-term gas prices, FEI assesses the natural gas commodity price risk to be not materially different compared to 2012.

Electricity Prices

The operating costs advantage of natural gas over electricity has historically been, and continues to be, lower in BC relative to some other jurisdictions, in particular Alberta and Ontario, because of BC Hydro's low electricity prices. Although BC Hydro electricity prices are forecasted to increase in the future, FEI will still be faced with the competitive challenges of maintaining and attracting customers that do not exist to the same extent in other provinces.

Figure 10 shows the extent to which residential electricity rates differ from province to province, with major cities represented. It also demonstrates how the magnitude of the cost difference between electricity and natural gas differs among these jurisdictions. Natural gas has the lowest operating cost advantage over electricity in major cities in British Columbia and Quebec.

Figure 10: Residential Operating Cost Differences between Natural Gas and Electricity



Assumptions:

- Electricity rates are as per the Hydro-Québec *Comparison of Electricity Prices in Major North American Cities* for rates in effect April 1, 2014
- Natural gas rates are effective January 1, 2015
- The efficiency of gas equipment is assumed to be 90% relative to 100% for electricity to determine equivalent electricity.
- Estimated bills are calculated based on annual use rate of 90 GJs
- All bills are exclusive of applicable franchise fees and taxes (with the exception of BC Carbon Tax)
- 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

Even with recent BC Hydro rate increases, the price of electricity is still relatively low in BC compared to major cities in Alberta and Ontario, and is largely reflective of heritage or historical costs of supply. A large percentage of the costs making up BC Hydro's electricity rates are the low embedded costs of the province's hydro generation facilities.

Electricity rates in Quebec, which are also low compared to Alberta and Ontario, are also significantly influenced by relatively low embedded costs. In Alberta and Ontario, by contrast, electricity prices are based on market forces. In Alberta, electricity is generated mainly by the combustion of coal, which is generally more expensive than the historical cost hydro generation in British Columbia. Ontario has the most diverse electricity supply mix in Canada, with nuclear being the main source of electricity generation, followed by hydro and then natural gas. Despite the diversity of supply in Ontario, it has higher electricity costs than Quebec and BC.

The narrower operating cost advantage of natural gas over electricity in BC represents a greater challenge for FEI than exists for natural gas utilities in other jurisdictions like Alberta and Ontario. The relatively narrow operating cost advantage makes it more difficult to overcome obstacles to natural gas adoption such as greater price volatility and higher capital and installation costs, which are discussed next.

5.2 Commodity Price Volatility

Natural gas prices are more volatile than electricity prices in BC due to the fact that natural gas is market-based, while electricity is primarily cost-based. Price volatility is an impediment to attracting and retaining natural gas customers because it can have a negative impact on natural gas rates and can taint consumers' view of using natural gas as a fuel. Greater price volatility can be perceived as leading unavoidably to ever higher prices and rates in the future.[13]

Despite the abundance of shale gas supply in North America, natural gas prices continue to remain volatile due to infrastructure constraints and during periods of high demand. FEI is not expecting this to change in the near future, especially if gas demand increases relative to supply as discussed in Section 5.1. Therefore, FEI's assessment of price volatility risk has not changed from its assessment in 2012 and is higher than the Commission's assessment.

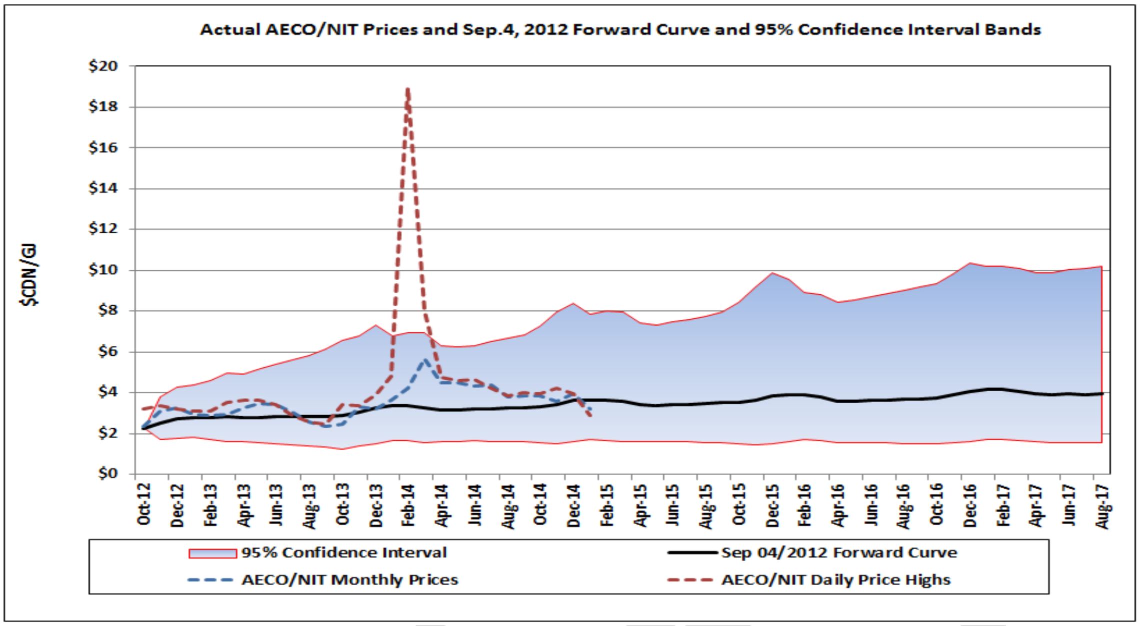
The issue of natural gas price volatility was discussed during the 2012 GCOC Stage 1 proceeding. The Commission's Decision stated that the September 4, 2012 AECO/NIT forward price curve, provided during the proceeding, projected relatively stable forward prices out to 2017 and concluded that this indicated some level of stability over the next few years.[14] In fact, this has not been the case. The following figure shows the September 4, 2012 forward AECO/NIT prices with the potential price range[15] compared to the actual AECO/NIT monthly and daily prices since that time. The actual daily spot prices in winter 2013/14 far exceeded the potential price range predicted in September 2012.

[13] Sampson Research, 2012 FEU Residential End-Use Study - Section 4.2.7.

[14] FBCU 2012 Generic Cost of Capital Proceeding (Stage 1), Commission Decision May 10, 2013, page 32.

[15] The price probability range represents the market's view of potential future gas price movements based on a 95% confidence interval. It is derived using implied volatilities for future months. Implied volatility is the volatility of the price that is assumed by the market based on an option pricing model, such as Black-Scholes.

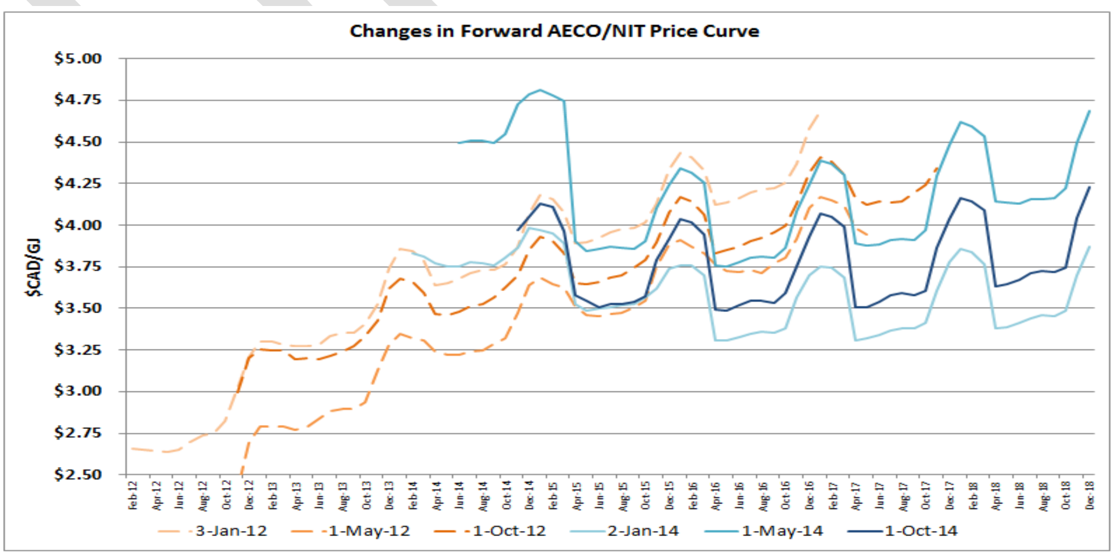
Figure 12: AECO/NIT Actual Prices vs. September 4, 2012 Forward Price Curve



A single forward price curve only represents prices that could be transacted on a particular date, for example September 4, 2012, for delivery of gas at a certain point in the future. It does not reflect the potential variability in future prices based on changing market supply and demand factors, nor where future market prices will ultimately settle.

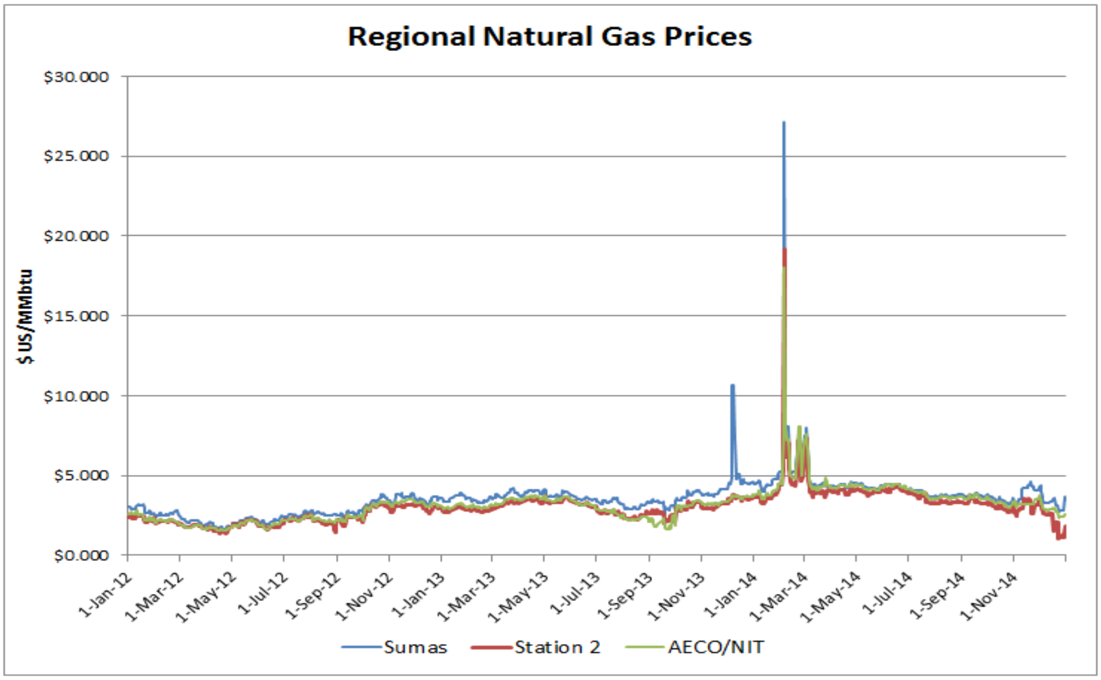
The following figure illustrates how forward market prices have changed since 2012. While the forward market price curves are now somewhat lower than they were in 2012, they are still subject to a considerable amount of volatility as market price outlooks change with fluctuations in supply and demand.

Figure 11: Changes in AECO/NIT Forward Price Curves



A closer examination of recent market price volaility is warranted. The following figure shows regional natural gas prices since 2012.

Figure 13: Regional Natural Gas Prices January 2012 to December 2014



Regional settled gas prices continued to be volatile in 2013 and 2014, particularly at the Sumas, AECO/NIT and Station 2 market hubs. Prices at the Sumas market hub often disconnect from other regional prices, such as those at the Station 2 and AECO/NIT market hubs, in times of cold weather and high regional demand. This occurs because winter demand reaches or exceeds the current maximum pipeline capacity that is available for the delivery of gas supply to Sumas.

In December 2013, Sumas prices disconnected from AECO/NIT and Station 2 prices and spiked to over $10.00 US/MMBtu during a cold spell in the Pacific Northwest (PNW) region. Moreover, during a cold spell in February 2014, unlike in December 2013 where only the Sumas price was disconnected, the AECO/NIT and Station 2 prices also spiked and reached to their highest price levels ever, due to high gas production freeze-offs[16] and low gas inventory levels in Alberta. AECO/NIT and Station 2 prices spiked and settled close to $20.00 US/MMbtu and Sumas gas prices settled at over $25.00 US/MMBtu.

[16] Natural gas wellhead freeze-offs happen when outside temperatures drop below freezing in producing fields. If the wellhead is not protected then water and other liquids in the gas can freeze and block the flow of gas.

Regional Infrastructure

This regional market price volatility is not expected to diminish any time soon. Regional infrastructure additions can help mitigate some of the regional price disconnection risk; however, these additions require a long time to plan, to secure shipper commitments, to receive regulatory approval, and to construct. The Southern Crossing Pipeline, Mt. Hayes LNG, and Mist and Jackson Prairie storage facilities expansions are examples of regional infrastructure that were approved and subsequently constructed to meet growing regional demand that helped to reduce some of the regional constraints. However, further infrastructure may be needed to meet the pace of demand growth in the PNW region if new industrial base load is added.

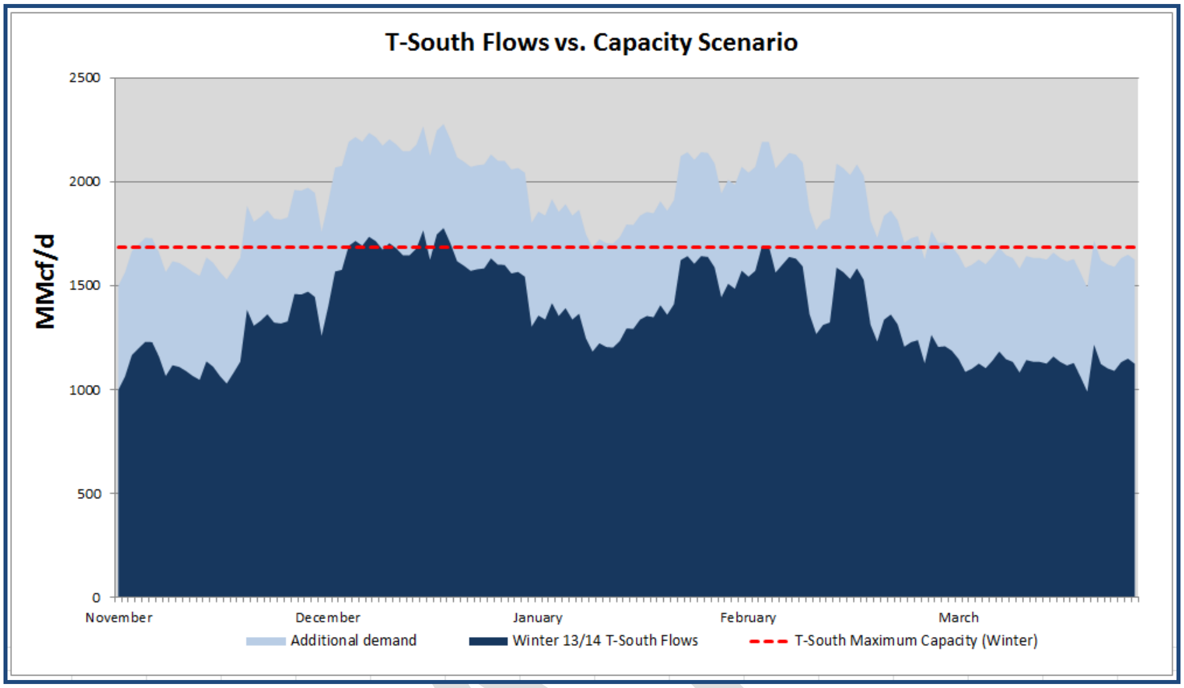
Going forward, increased regional demand could exacerbate this situation until new infrastructure can be built. Significant new demand could come from proposed projects such as Woodfibre LNG, Tilbury LNG expansions, Carty Generation Station, Boardman Coal Plant retirement, Centralia 3 power plant, Grays Harbor Energy Generation Plant Expansion, and the Northwest Innovation Works Methanol Plants[17], and Oregon LNG. These projects will likely require gas supply from northern BC, using Spectra's T-South pipeline system to move supply to their facilities in southern BC and/or the U.S. PNW. However, this incremental demand requires greater pipeline capacity on T-South than is currently available. FEI's industrial customers, as well as those in the US PNW, responsible for arranging their own transportation risk being left without access to sufficient capacity to meet all of their demand because they may not be able to meet the requirements needed to underwrite the development of new transportation capacity.

In its 2014 Gas Outlook, the Northwest Gas Association (NWGA) estimated that there could be an additional 100 MMcf/d of natural gas demand in the PNW region by the end of 2023 due to expanded power generation demand, mainly from coal plant retirements. In addition, Oregon LNG received NEB export license approval to export 1.3 Bcf of gas from the PNW region by 2019. Furthermore, an additional 960 MMcf/d of natural gas demand might come online from three recently proposed methanol plants in Washington and Oregon along the I5 corridor.[18] Depending on how incremental capacity on T-South is underwritten, some current demand served by T-South may be left without capacity. The consequence of this outcome would likely result in higher regional spot prices and more price volatility or unserved demand, especially during high demand periods.

The following figure compares what winter 2013/14 T-South flows would look like with an additional 500 MMcf/d of gas demand (light blue) from these incremental projects to current pipeline capacity levels.

[17] NW Innovations Works presentation to NWGA Board, December 5, 2014.
[18] Ibid.

Figure 14: T-South Flows vs. Capacity Scenario



While expanding the Spectra T-South system is an option, along with other pipeline solutions, these require long-term shipper commitments and several years to complete.

Price Risk Management

FEI's current price risk management strategies help to somewhat mitigate regional market price disconnections and regional market price volatility. These include the use of commodity rate setting mechanisms, deferral accounts and the optional Equal Payment Plan to help smooth commodity rates and bills for customers. However, FEI continues to operate without any price risk mitigation strategies that directly impact underlining market prices, such as hedging activities, and therefore FEI's supply portfolio continues to be subject to market price fluctuations.

FEI believes that the addition of other price risk management tools and strategies would help with mitigating market price volatility and its impacts on commodity rates. FEI submitted the 2014 Price Risk Management Review Report (Review Report) to the Commission on October 20, 2014. In this report, FEI recommended the use of more comprehensive price risk management strategies, including a responsive medium-term hedging program and consideration of longer-term price risk management tools. FEI is currently leading a series of workshops with interested stakeholders to discuss the Review Report recommendations and determine if any strategies will be submitted to the Commission for approval. At this time it is not known if the workshops will lead to the development of additional price risk management strategies to help FEI mitigate market price volatility on behalf of customers.

With regional market price volatility continuing, regional infrastructure becoming more constrained in the future, and continuing uncertainty regarding FEI's additional price risk management tools to manage the underlying gas price volatility from market fluctuations, FEI assesses the risk associated with market price volatility to be similar to 2012 but higher than the Commission's expectations in 2012.

5.3 Upfront and Installation Costs

Sections 5.1 provided an overview of natural gas price competitiveness on the basis of operating costs. In this section, the price competitiveness will be analyzed considering the upfront capital cost differences between natural gas and electricity end-use applications (space and water heating).

This analysis is relevant to the challenges faced by FEI in attracting new customers. Builders and developers are the primary decision makers as to what energy source and equipment are used in new construction. As builders and developers do not pay the operating costs, they tend to be more influenced by capital costs alone. A builder or developer also strives to maximize the useable square footage available from the development to maximize their return on investment. Capital cost savings and the ability to sell more useable living space incents developers and builders to install electricity equipment over natural gas equipment in new developments. The following excerpt from a 2014 report by IHS CERA[19] confirms FEI's standpoint:

> *"Finally, builders and landlords generally prefer to install appliances with lower up front capital costs, even though they may have higher operating costs, as builders do not generally have to pay operating costs. For this reason, the builder/landlord preference usually favors the electric appliance over the gas one unless customers request gas"*[20].

Table 6 below provides as an example the upfront installation (capital) cost difference associated with natural gas versus electricity for a space heating furnace and hot water tank for new construction. In this example, assumptions were based on a single family dwelling (Medium Size, 3000 square feet). When considering smaller multi-family dwellings ("MFD"), such as townhouses and apartment units, the higher capital cost of natural gas further decreases cost competitiveness of natural gas in space and water heating applications.

Table 6: Upfront and installation Costs for Space and Water Heating

	Space Heating	Water Heating
Capital costs for natural gas	$9,000	$2,000
Capital costs for electric	$4,435	$1,000
Difference in capital costs	**$4,565**	**$1,000**

[19] IHS CERA is a U.S. based consulting firm that specializes in advising governments and private companies on energy markets, geopolitics, industry trends, and strategy. CERA has research and consulting staff across the globe and covers the oil, gas, power, and coal markets worldwide.

[20] http://www.fuelingthefuture.org/assets/content/AGF-Fueling-the-Future-Study.pdf.

Notes:

- Assumptions based on the new construction of a home in the Lower Mainland (Medium Size Dwelling at 3000 square feet).

Compared to 2012, the difference in upfront capital costs between natural gas and electricity for space heating and water heating purposes has not materially changed. Therefore FEI has assessed that the risk associated with the upfront and installation costs has remained unchanged.

The IHS CERA report also recognizes that even when the operating and upfront capital costs are paid by the same end-user and not the developer and builder, the relatively long pay-back period may be a deterrent to customers:

> *"The natural gas advantage is realized over time as lower fuel costs gradually overcome the higher initial costs, but payback periods may be longer than consumers are willing to accept."*

This statement can be analysed by combining the effects of upfront and installation costs with the operating costs. As demonstrated in Table 7 the difference in upfront capital costs between gas and electric means that over the life of the appliance the operating cost advantage between natural gas and electricity would have to be at least $13.84/GJ for space heating and $5.25/GJ for water heating for the installation of the natural gas rather the electric equipment to be economic for the a consumer.

The difference in unit capital costs between natural gas and electricity is larger than what was reflected in the data FEI presented in 2012, particularly for space heating. The increase is explained by lower energy consumption assumption for space heating[21].

Table 7: Difference in Costs for Space and Water Heating

	Space Heating	Water Heating
Difference in capital costs	**$4,565**	**$1,000**
Operating costs per year	$422	$116
Maintenance costs per year	$100.00	$0.00
Total costs per year to pay off difference in capital cost	**$522**	**$116**
Energy consumption (GJ)	38	22
Difference in costs between natural gas and electricity over measureable life ($/GJ)	**$13.84**	**$5.25**

Notes:

- Assumptions based on the new construction of a home in the Lower Mainland (Medium Size Dwelling at approximately 3,000 square feet), interest rate of 6% and the measurable life of 18 years for space heating furnace and 13 years for hot water tank.

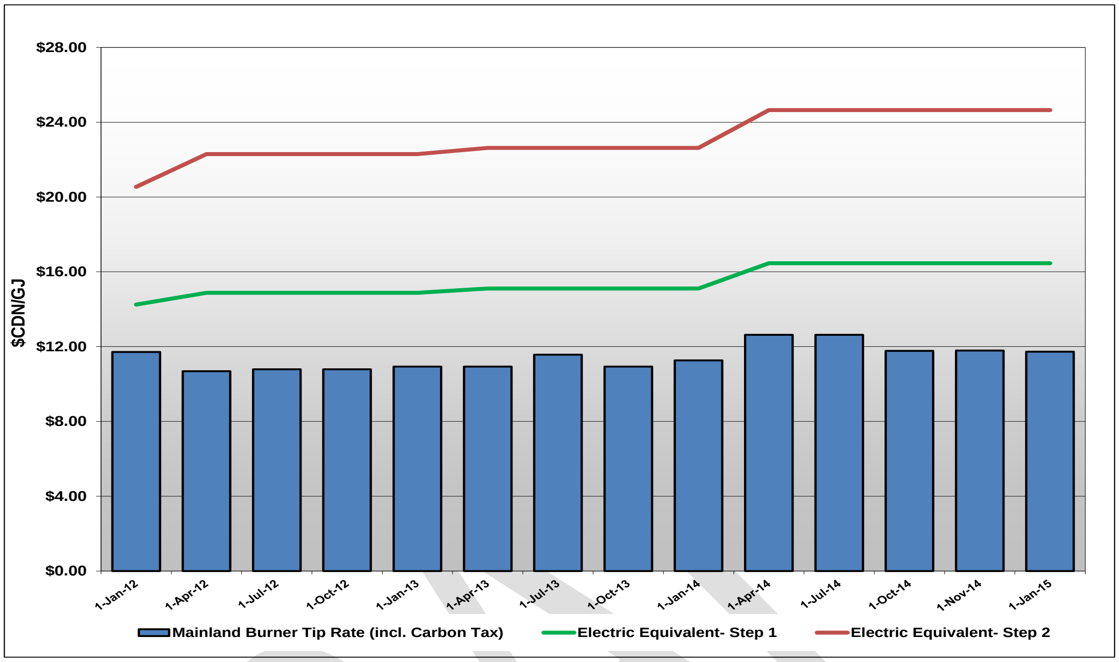
Figures 15 and 16 present a historical view of FEI's competitiveness with space heating.[22] As shown in Figure 15 below, FEI's burner tip rate absent the capital costs

[21] The new consumption assumption is based on new ENERGY STAR rated homes that perform 20% above building code. This explains the lower consumption for space heating.

[22] FEI burner tip rate presented in the figure includes the commodity charge, storage and transport charge, fixed basic and delivery charges, and the Carbon Tax to provide a comparison against the electric equivalent. The Step 1 and Step 2 BC Hydro RIB rate electric

(indicative of a customer that already has appliances installed) have been below the average rate and Step 1 electric equivalents since 2012.

Figure 15: FEI Mainland Service Territory Existing Space Heating Burner Tip Rate vs. Electric Equivalents



The inclusion of the upfront capital costs associated with the installation of a gas furnace (indicative of a customer that directly incurs the upfront capital costs of installing gas over electric appliances) reduces FEI's competitive position against the electric equivalents. From January 2012 to about January 2015, FEI's burner tip rate plus the capital cost put the total cost per GJ above the Step 1 electric equivalent. Higher total costs of installing gas over electric indicate to the consumer that electricity is the more economical option.

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equivalents have been adjusted using a 92% efficiency to represent the average efficiency level of a new gas fired furnace in Figure 14. Similarly, the Step 1 and Step 2 electric equivalents have been adjusted using a 75% efficiency to represent the average efficiency level of all existing space heating customers in Figure 15. It is important to note that the rate the BC Hydro customers ultimately pay is dependent on their actual consumptions (Step 1 and Step 2). This can impact the rate comparisons of natural gas against electricity depending 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).

Figure 16: FEI Mainland Service Territory New Space Heating Burner Tip Rate and Capital Cost vs. Electric Equivalents

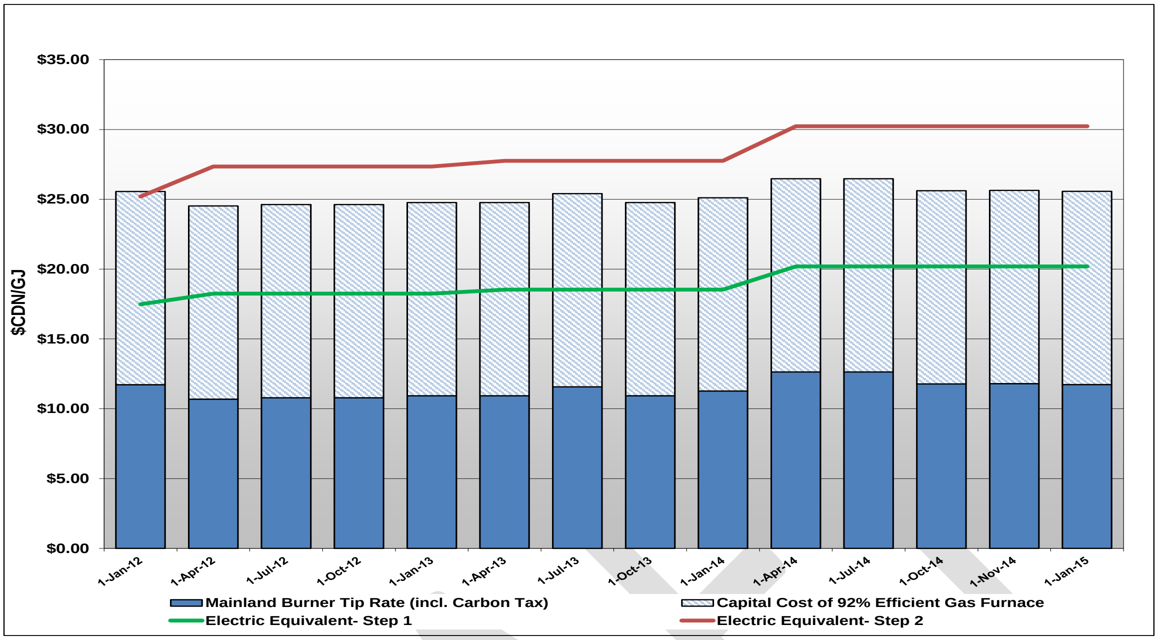
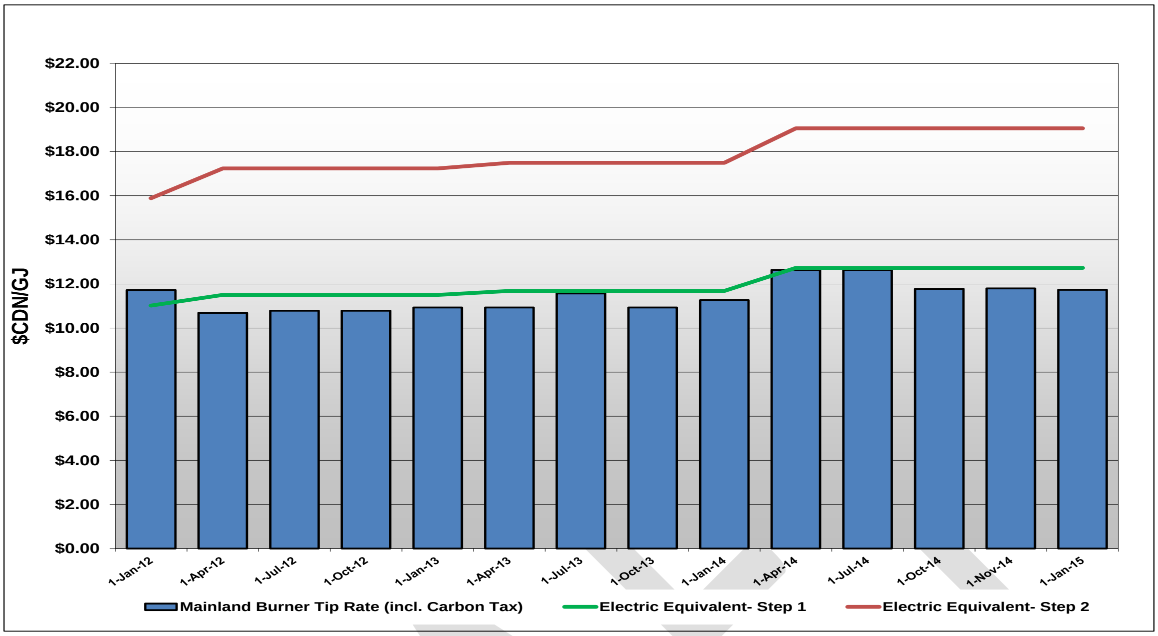


Figure 17 and Figure 18 below present a historical view of FEI's competitiveness in the water heating market. The FEI burner tip rate includes the commodity charge, storage and transport charge, fixed basic and delivery charges, and the Carbon Tax to provide a comparison against the electric equivalent. The Step 1 and Step 2 electric equivalents have been adjusted using a 58 percent efficiency to represent the efficiency level of a current installed gas fired hot water heater for Figure 17 and 62 percent for Figure 18 to represent the efficiency level of a newly installed gas fired hot water heater.

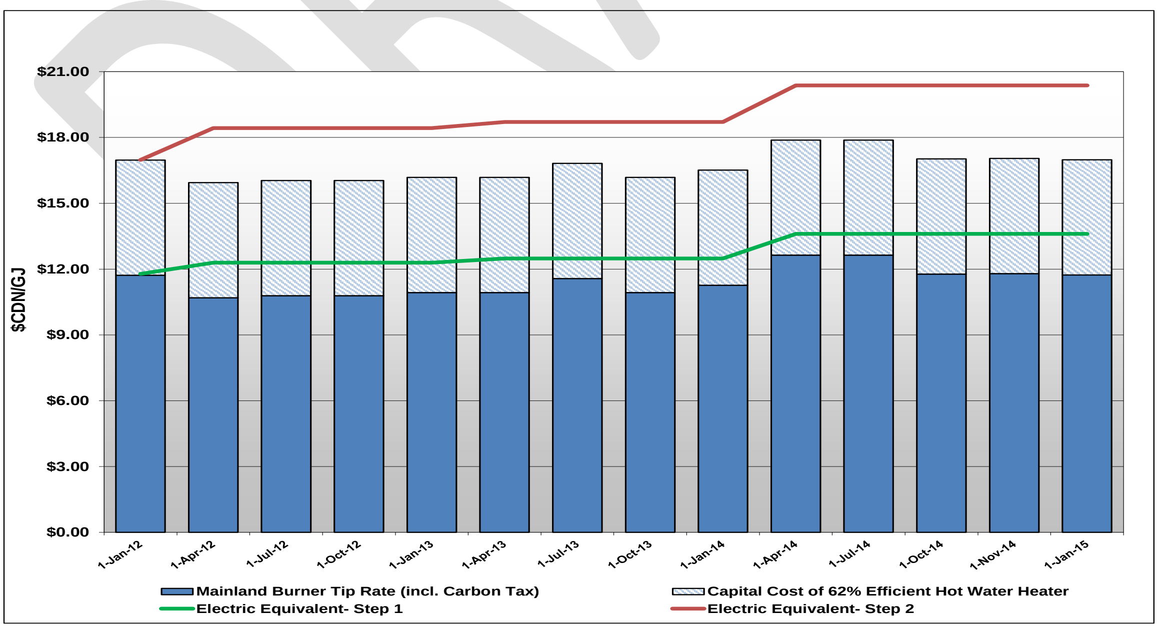
Figure 17 shows the comparison without capital costs, which is indicative of a customer that has existing water heating equipment and therefore the energy equipment is a sunk cost.

Figure 17: FEI Mainland Service Territory Existing Water Heating Burner Tip Rate and Capital Cost vs. Electric Equivalents



The inclusion of the upfront capital costs associated with the installation of a gas hot water heater reduces FEI's competitive position against the electric equivalents. From January 2012 to January 2015, FEI's burner tip rate plus the capital cost put the total cost per GJ above the Step 1 electric equivalent.

Figure 18: FEI Mainland Service Territory New Water Heating Burner: Tip Rate and Capital Cost vs. Electric Equivalents



Until recently with the increase in BC Hydro electric rates, FEI's burner tip rate plus capital costs have totalled marginally above the Step 2 electric equivalent. The lower capital costs for water heating coupled with higher BC Hydro rates, have increased the price competitiveness of natural gas in the water heating sector. Natural gas burner tip rates plus capital costs remain slightly above the Step 1 electric equivalent.

Until the January 1st, 2018 when the phase-in period is completed, delivery rates for the Vancouver Island and Whistler service territories remain higher than mainland delivery rates and therefore the competitiveness of natural gas compared to electricity for these service areas continue to be lower than FEI.

In general, with recent increases in electricity prices the current price competitiveness of natural gas has marginally improved, other things being equal. However, as discussed in the market shift risk and political risk sections, the improved price competitiveness of natural gas continues to be muted by non-price factors.

6. MARKET SHIFTS RISK

The choice of energy, and how it is consumed and produced, is influenced by the introduction of new technology and energy forms, changing customer perceptions of energy, and the types of homes being built. Market shifts in these areas continue to pose challenges to FEI's ability to attract and retain customers, and maintain market share and throughput levels.

The available data since the 2012 GCOC proceeding has reaffirmed that the declining trend in throughput level, particularly in residential sector, is mainly due to two continuing trends: (a) declining annual use trends from existing and new customers mainly caused by the improvements in energy efficiency and conservation as well as smaller average dwelling size; and (b), the weak capture rate in the new construction market in the growing multi-family sector.

6.1 New Technology and Energy Forms

FEI's assessment is that new technology and energy forms present similar risks for FEI Amalco as they had presented for the benchmark utility FEI in the GCOC proceeding.

In 2012, FEI identified that the adoption of different energy forms in combination with newer technologies represents a challenge to FEI's core business of providing natural gas for space and water heating. FEI addressed the fact that numerous new end-use technologies have entered the energy services marketplace in recent years and will likely continue to do so in the foreseeable future. Developers are responding to their customers' desires for efficiency and innovation by in some cases installing newer technology that, while similarly or higher priced than gas equipment, suggests to the buyer that the homes are more advanced and efficient. These houses then command a higher margin for the developer and natural gas is squeezed out.

In addition to advancements on both natural gas and electricity-based heating equipment, advancements in renewable thermal energy solutions have emerged to take a small but growing slice of the market. Examples of renewable thermal solutions include air and ground source heat pumps for single family residences; and district energy systems that can employ one or more renewable energy systems such as waste heat from industrial processes, geo-exchange technologies, or biomass solutions often in combination with natural gas-fired heating solutions. FEI continues to assess how these renewable thermal solutions are impacting natural gas demand and how they are changing the way customers are using natural gas. This increasing competition indicates that the utility delivery model may potentially shift over the long term.

The application of existing alternative technologies and the introduction and adoption of new technologies and energy forms has implications for FEI.

- First, renewable thermal energy solutions such as geo-exchange systems, waste heat recovery systems and solar thermal systems can displace both existing and future expected demand for natural gas. While FEI does not offer these services to its customers, the potential for other third party service providers to do so creates a risk to FEI's annual demand profile.
- Second, the changing landscape of technologies influences codes and regulations and building design and controls, which can have an impact on energy use.

In recent years, non-government organizations such as the Community Energy Association and Quality Urban Energy Systems of Tomorrow (Quest) are acting as catalysts to spur interest in district energy systems. A Quest progress report published in August of 2013 provided a brief overview of the integrated community energy solutions (ICES) in BC.[23] According to this progress report, more than thirty district (multiple customers) and discrete heating systems were operational in 2013 with more than ten projects were in advanced planning, design or approval with many more being at the feasibility study stage (for a detailed list of projects and technologies used please refer to the Quest's progress report).

Government is also a factor in the trend towards alternative energy forms. The Province has expressed support for the development of district energy systems in a number of ways. For example, BC's Government infrastructure planning grant program offers grants up to $10,000 to support local government in projects related to the development of sustainable community infrastructure. Along with supporting the development of new technologies and energy forms in residential and commercial sectors, the BC Government has also strived to promote the use of alternative fuels and new technologies in industrial sector. For instance, the 2015 BC provincial budget includes a three year transitional incentive plan of $22 million paid over a three year period, to encourage the BC Cement industry to adopt cleaner fuels and further lower emission intensities. The lower carbon and zero-carbon alternatives the industry is exploring

[23] http://www.questcanada.org/sites/default/files/files/ICES%20Progress%20Report%20-%20Province%20of%20BC(1).pdf.

range from waste wood and un-reusable residuals from recycling to bio coal[24]. According to the Canadian Cement Association, the major plants operated by the two major cement manufacturers in BC would use the money to help subsidize the development of alternative fuel sources[25].

Examples of requirements adopted by local governments for developers to consider alternative energy systems are addressed later in the political risk section of this Appendix.

Since 2012, a number of regulatory exemptions have been granted to companies that provide new technology and renewable energy services. These exemptions further facilitate the development of these industries and increase their competitiveness against regulated utilities. One such an exemption is the recent Order in Council No.23 that exempts the "*class of cases where a person, not otherwise a public utility, offers lease agreements or energy supply contracts providing lessees or buyers with solar or wind energy systems or facilities, that could otherwise be purchased on the open market, provided that the value of the installed system including equipment, labour and permits, does not exceed $500,000*"[26]. This exemption will allow entities such as Vancouver Renewable Energy Cooperative (VREC) to be free from the Commission's scrutiny.

6.2 Perception of Energy

FEI's assessment is that perception of energy presents similar risks for FEI Amalco as they had presented for the benchmark utility FEI in the GCOC proceeding.

Historically, customer energy choices tended to be driven by market factors such as energy price, accessibility, ease of use, reliability, and availability. FEI's customers are now also influenced by a desire to use energy efficiently and to adopt lower carbon and renewable energy sources. This creates challenges for natural gas utilities generally in retaining and attracting heating load, despite the lower natural gas commodity prices currently being experienced. FEI has conducted a number of surveys and studies since the 2012 GCOC Application. Figure 19 summarizes key findings from recent FEI surveys that were undertaken to understand how consumers perceive their home energy options.

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24 http://www.vancouversun.com/business/resources/Cement+industry+fires+search+alternative+fuels+reduce/10881358/story.html

25 Coal and natural gas are the main substitute fossil fuels that are used in cement production and an increase in the use of alternative fuels could negatively impact FEI's industrial throughput.

26 http://www.bcuc.com/Documents/SpecialDirections/2015/01-16-2015_OIC23-VRECExemptionApproval.pdf.

Figure 19: Summary of Customer Perception Research

Alternative Energy Surveys
2009, 2010 and 2012

- Assessed the public's willingness to adopt alternative energy technology, and associated with this, their willingness to pay for them.
- Indicated that while BC residents' awareness and knowledge of alternative energy sources remained steady in 2012 when compared to 2010, they continue to strongly favour incorporating alternative energy sources into new homes. The willingness of BC's residential market to incorporate alternative energy sources has softened in recent years from 69% (2009) to 62% (2013). Barriers identified include: (a) the high capital costs of adoption; and (b) builders and developers cite a lack of voiced demand.

Gas is Good Campaign Assessment
2013 and 2014

- Measured the public's preference for natural gas appliances and their likelihood to consider natural gas appliances in their home buying decision. The study coincided with the Gas is Good advertising campaign which was focused on people looking to buy homes.
- The study showed that over a 12 month period, the percentage of residents receptive to natural gas doubled from 16% to 34%. Over the same period the percentage of respondents who mentioned heating systems as an important factor when buying a new home tripled from 3% vs. 10%.

Energy Source Usage Preferences Study
2011 and 2013

- Tracked and measured preferences for future energy sources and attitudes impacting future energy sources.
- A sizeable number of households continue to be unhappy with the energy source they currently use. Furthermore, results show a decided preference for geothermal heat pumps for space heating (50%) compared to a natural gas furnace (43%). In terms of water heating, respondants preferred a tankless water heater (47%). A storage water heater was the second most favorable option (31%). Respondants indicate their energy source preferences for space and water heating are primarily influenced by perceived reliability of the energy source, followed by perceived safety of the energy source.

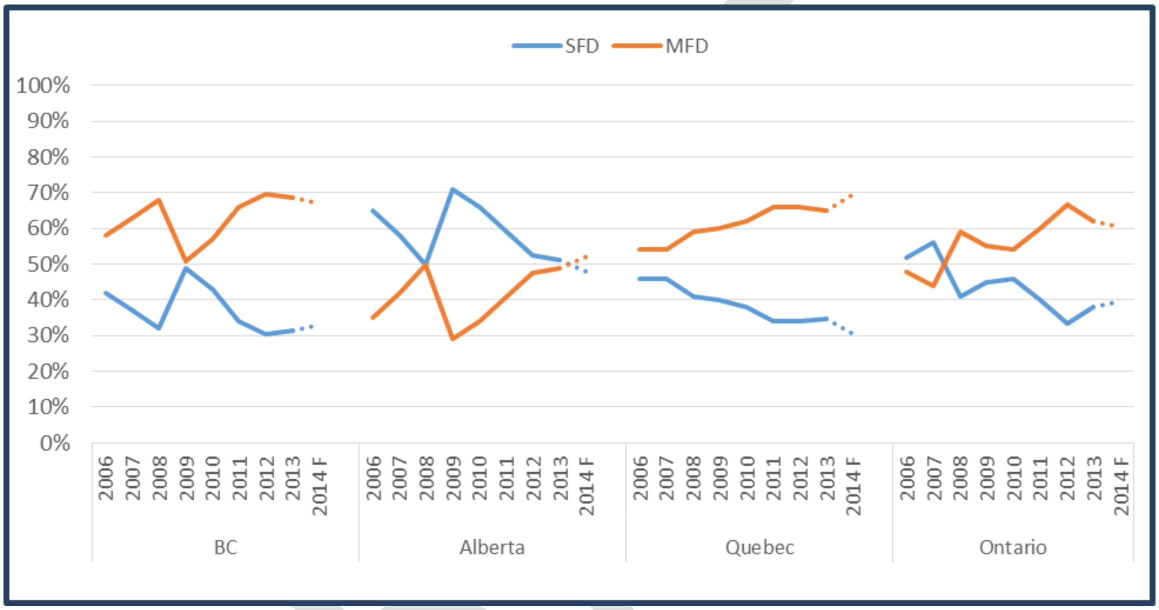
These surveys indicate a gap between developers' preferences (currently used systems in place) and end-use customers' preferences. For instance, gas ranges and cooktops are preferred for cooking even though electrical ovens are more common. The differences between preferred and currently used systems can stem from many barriers ranging from financial disincentives to a lack of strong desire for change.

6.3 Housing Types

The market shift in new home development (from single family to multi-family) is adversely impacting FEI's natural gas use and capture rates in a manner similar to what was taking place in 2012. Considering the current lower capture rates in Vancouver Island service area, amalgamation has had a slightly negative impact on FEI Amalco's overall capture rate. Nevertheless, the amalgamation will bring about large rate decreases on Vancouver Island over the three year phase-in period and may well improve the capture rates (in other words, historical capture rates may not be indicative of capture rates going forward).

As shown in Figure 20, there is still a significant gap between the single-family and multi-family housing starts with close to 70 percent of all housing starts classified as multi-family dwelling. Drivers for the increase in multi-family dwellings include affordability, shortage of building space, population growth, climate change policies and proximity to public transportation and shopping hubs.

Figure 20: Single Dwelling vs. Multi-Family Housing Starts in Selected Canadian Provinces

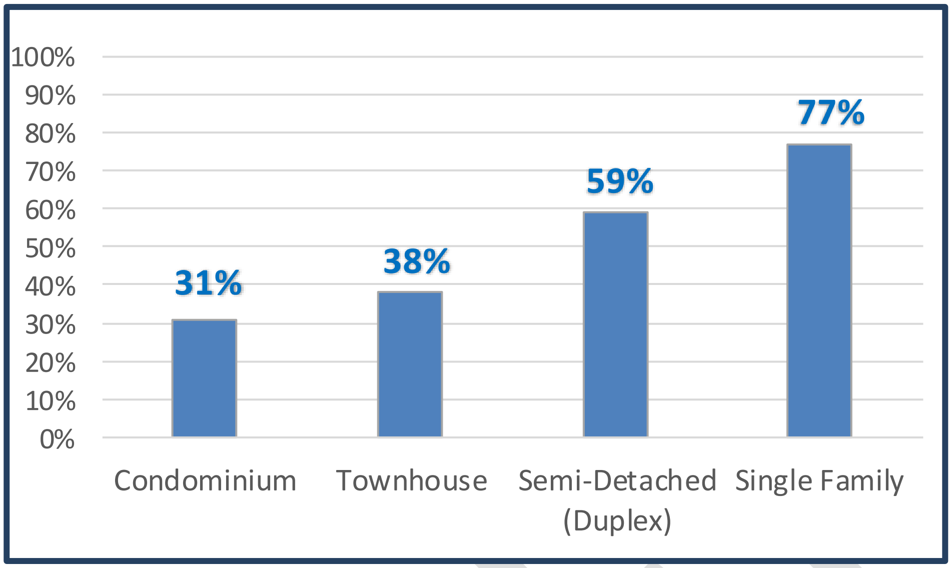


There are two key implications for FEI of the mix favouring multi-family dwellings.

First, in line with previous studies, the 2012 Residential End Use Study (REUS) survey shows that, on average, annual consumption for natural gas is greater in single-family dwellings than in multi-dwellings. In order to maintain existing throughput levels in an environment where single-family dwelling housing starts are trending lower, natural gas utilities will need to capture more multi-family dwellings to offset the reduced levels of system throughput related to improvements in energy efficiency and technology.

Second, natural gas has a low penetration rate in multi-family dwellings. Figure 21 shows amalgamated FEI's capture rates by housing types for 2013.

Figure 21: Combined FEI/FEVI/FEW Capture Rates by Housing Type (2013 data)



The lower capture rate for multi-family dwellings is primarily driven by the unfavorable economics of installing a natural gas application as compared to an electric equivalent.[27] This is especially true for developments where the unit cost plays a primary role in the purchasing decision. In general, developers have a strong incentive to install electric baseboard heating for multi-family dwellings, as opposed to natural gas, given the comparatively high capital costs of natural gas heating appliances, ducting and overall installation costs. Natural gas space heating equipment also occupies valuable living space within a multi-family unit which could otherwise contribute towards a developer's return.

Mathematically speaking, amalgamation has lessened capture rates in most of the housing types. For instance, in the single family dwelling category, the amalgamated FEI's capture rate is around 77 percent while FEVI's and non-amalgamated FEI's capture rates were 52 and 84 per cent respectively. The same trend can be seen in other housing types. However, the full effects of amalgamation on capture rates will not be seen until after the three year phase-in has completed.

Over the longer term it is expected that electricity will continue to enjoy a greater market share in the multi-family dwelling sector than natural gas.[28]

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[27] American Gas Association. Squeezing Every BTU: Natural Gas Direct Use Opportunities and Challenges. page 36.

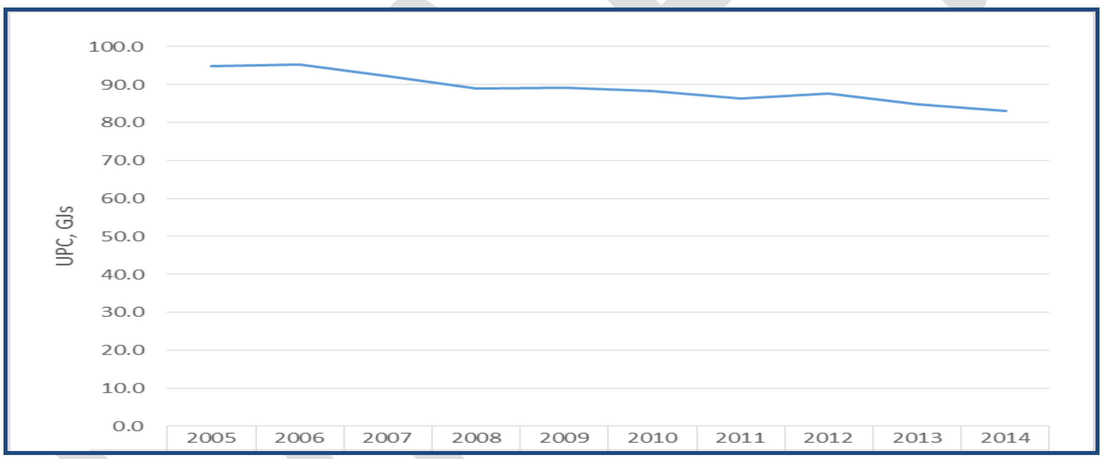
[28] BC Hydro confirmed this expectation in its 2012 Integrated Resource Plan, stating: "Since row houses and apartments are more likely to be built with electric heat compared to single family homes, the market share for electrically-heated housing is expected to increase." (Appendix 2A, 2011 Electric Load Forecast, page 27).

6.4 Changes in Energy Use

FEI continues to face declining annual use rates from its existing customers, primarily in the residential sector. This has a direct impact on throughput levels. The residential Use per customer (UPC) has been historically higher on the Mainland in comparison to the Vancouver Island service area. As such, blending in the lower UPC accounts from Vancouver Island means that the amalgamated FEI UPC is lower than for the pre-amalgamated FEI. On the other hand, FEI's commercial and industrial UPC increases with amalgamation, a function of the average UPC in those rate classes happening to be higher than pre-amalgamation average UPC in those rate classes. Similar to capture rates, the full effects of amalgamation on UPC will not be clear until the three year phase-in has happened. In the intervening period, it is reasonable to assess changes in energy use as presenting similar risks for FEI Amalco as they had presented for the benchmark utility FEI in the GCOC proceeding.

As shown in the Figure 22, FEU/amalgamated FEI's residential annual use per customer, or UPC, has declined by more than 12 percent since 2005.[29]

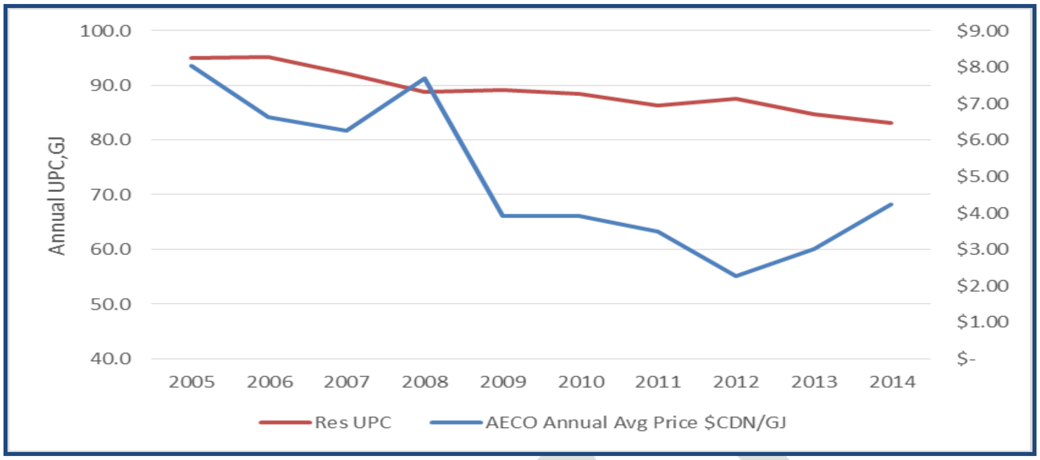
Figure 22: FEU/Amalgamated FEI's Residential (RS 1) Normalized UPC for Existing Customers



The decline in UPC is attributable to a variety of factors, including technological advances and energy efficiency improvements, building codes, size and type of homes being built, and type of appliance being installed in these homes. Commodity prices are also expected to influence customer use over time; however, actual changes in customer behavior in response to prices are difficult to determine from historical data. As shown in Figure 23 below, for the residential sector, average use per customer decreased during the period of rising prices but UPC has not rebounded during the low price environment experienced over the last couple of years. This is likely due to the influence of these other factors.

[29] The use per customer rates are based on historical data. It is expected that new customers use per account will be much lower than existing customers for a variety of reasons.

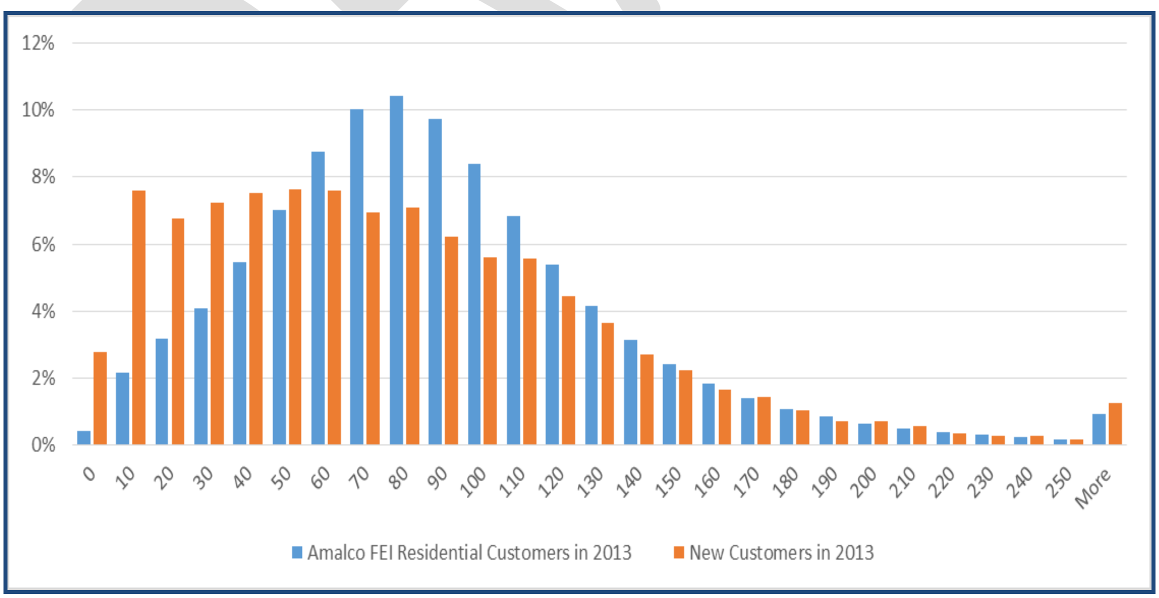
Figure 23: FEU/Amalgamated FEI's Residential UPC and Commodity Price



Short-run price elasticity reflects behavioural changes that a customer may make in response to changes in price, whereas changes in energy-consuming equipment (capital) would be captured in the long-run elasticity. Long-run elasticities are expected to be larger because customers can make adjustments in the capital stock.

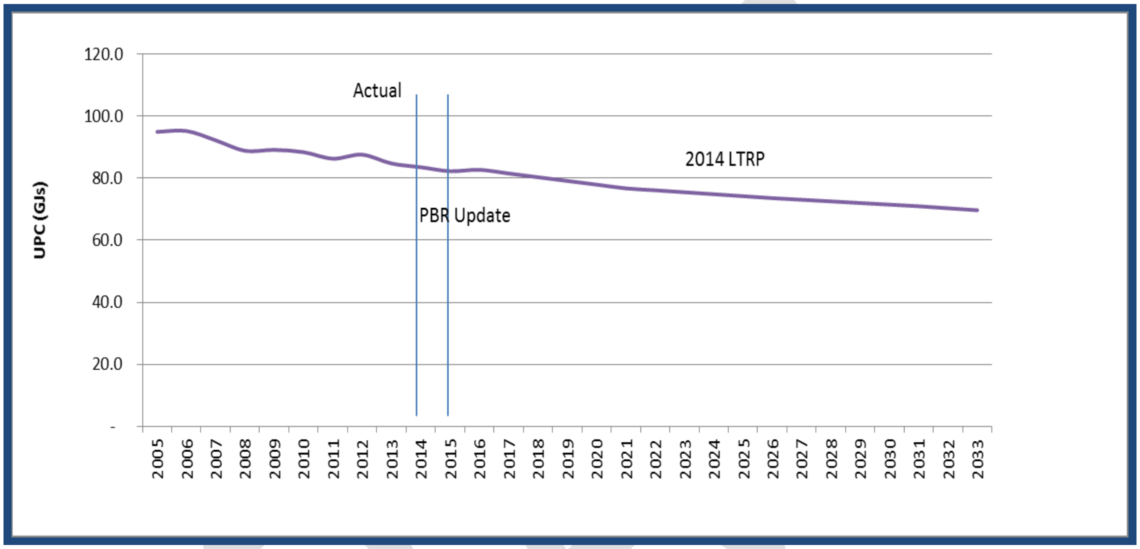
The implication of the research findings is that new customers will have a lower UPC compared to the existing customers as is illustrated in Figure 24. The frequency distribution curves for the existing and new customers are centered on 78 GJ and 64 GJ, respectively. This means that an existing natural gas residential customer on average consumes 78/GJ in a normal year as compared to a new residential customer which will consume 64/GJ in a normal year. This trend in UPC for new customer additions in the residential sector will have long-term impacts on the throughput from this sector.

Figure 24: Amalgamated FEI's Residential Frequency Distribution



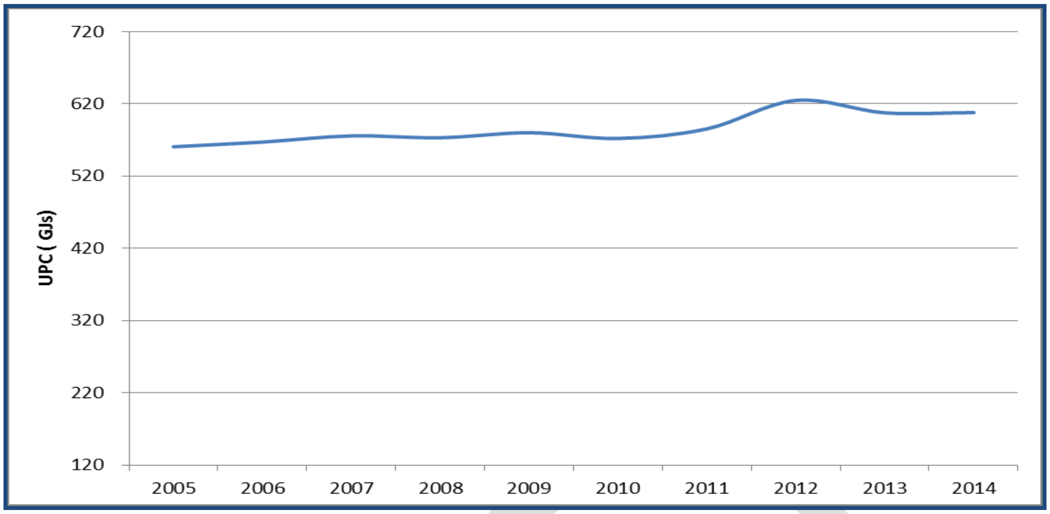
FEI's forecast of the decline in residential use rates is in line with the forecast from its 2014 Long Term Resource Plan (LTRP). As set out in the LTRP, natural gas consumption in the residential sector will naturally decline by an additional 8 percent from 2011 to 2033 (putting increasing pressure on delivery rates, all else equal), even in the absence of continued demand-side management. FEI also estimated in the LTRP that the total reduction as large as 12 percent on a cumulative basis from 2011 to 2033 can be achieved if new demand-side measures are implemented. Figure 25 illustrates the trend of amalgamated FEI's residential use rate for existing and new customers.

Figure 25: FEU/Amalgamated FEI's Residential UPC Actual and Forecast



FEI's commercial customers (Rate Schedule 2, 3 and 23) consist of customers from a wide variety of business sectors, as well as from condominiums and multi-family dwellings (greater than 4 units). Since this is a very diverse group of customers there are many factors affecting their natural gas use that may lead to counter-intuitive changes in the overall average commercial use rate. Figure 26 below shows the fluctuations in the annual use rate for the commercial rate class.

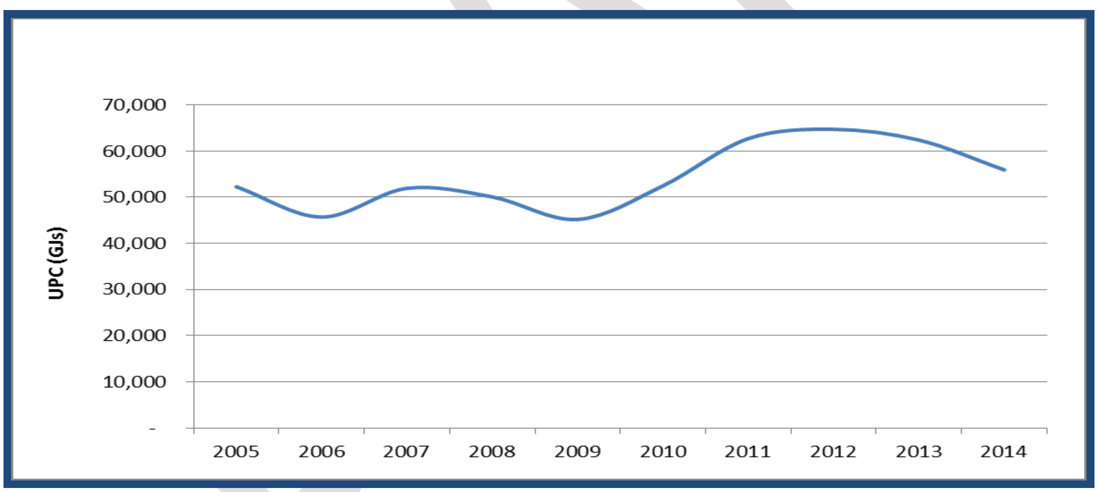
Figure 26: FEU/Amalgamated FEI's Commercial UPC



Forecasting the future use rate for the commercial rate classes is difficult due to the fluctuations in use rates for this sector.

Amalgamated FEI's/FEU historical industrial UPC is displayed in Figure 27.

Figure 27: FEU/Amalgamated FEI's Industrial UPC



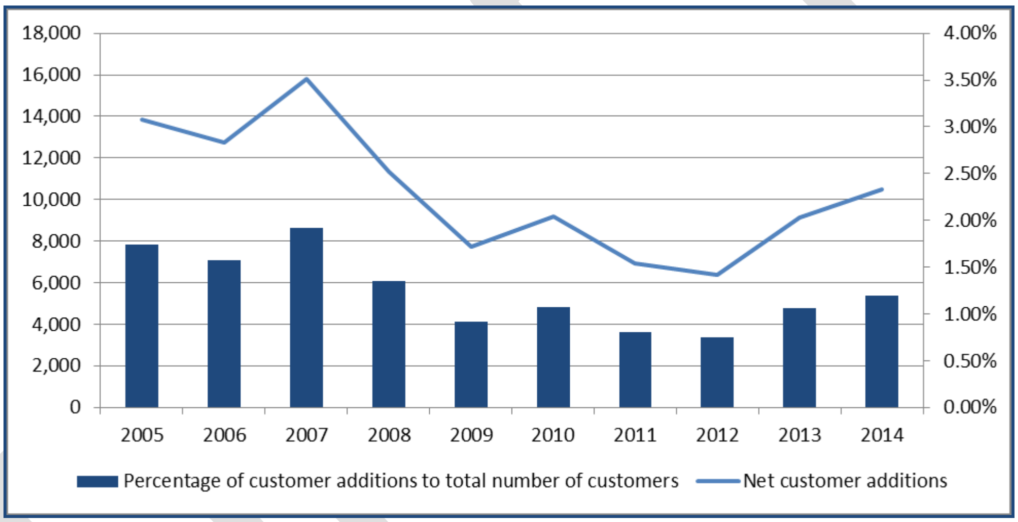
In 2010-2012, FEI amalco experienced a modest increase in throughput in the industrial sector as some industrial customers have fuel switched towards natural gas to take advantage of the lower natural gas prices compared to their alternatives. However this increase was temporary as industrial customers' demand slightly decreased in 2013 and 2014. These small variations in industrial demand are probably due to the price elasticity of demand for industrial customers as well as their business cycles.

6.5 Changes in Customer Additions

A further trend that compounds the declining use per customer is the weak capture rate for new building stock, primarily in the multifamily sector. FEI's ability to manage risk is in part dependent on its ability to attract and retain new customers to offset declines in UPC, and this is proving to be more difficult than it has been historically. These risk factors were present in 2012. FEI's assessment is that changes in customer additions present similar risks for FEI Amalco as it had presented for the benchmark utility FEI in the GCOC proceeding.

As shown below in Figure 28, FEU/amalgamated FEI's net customer additions increased in 2013 and 2014[30] however this increase was too small to compensate for the huge declines in the number of FEU customer additions over 2007-2012 period. FEI added a little over 10,000 residential customers (net of attrition) in 2014, which represents approximately 1.25 percent of the total number of customer in 2014.

Figure 28: FEU/Amalgamated FEI's Residential Customer Additions

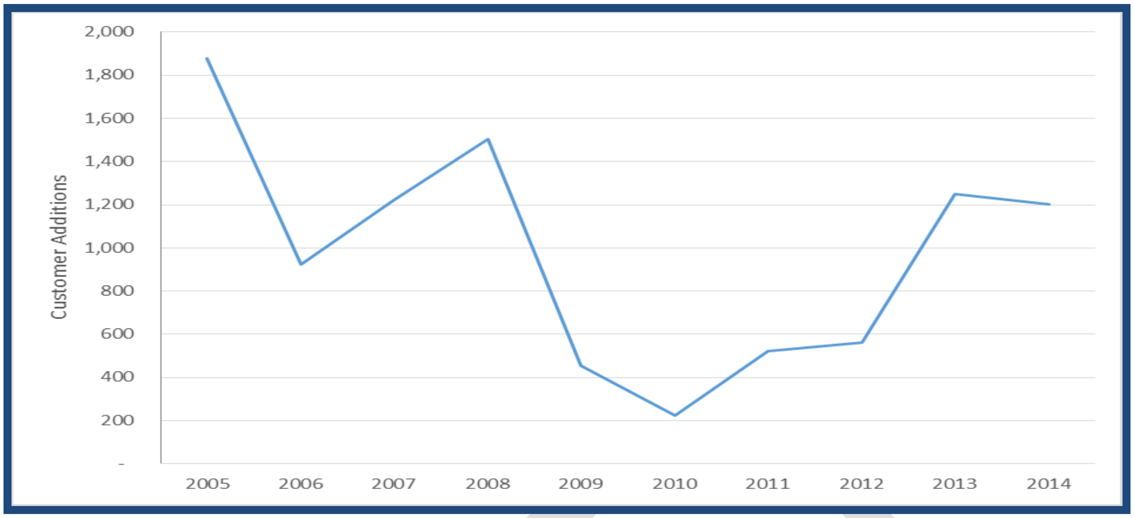


Residential customer additions are influenced by a number of factors, including the new construction market in BC, and the previously-discussed shift in the housing market towards more higher-density housing types where the Company has a low capture rate.

For commercial customers, as demonstrated by Figure 29, net customer additions are highly volatile and do not exhibit a clear trend.

[30] In 2013 and 2014, FEI undertook an initiative to repatriate customers that had a meter and service line but who had stopped taking service from FEI over the past few years. This resulted in a number of residential as well as commercial net customer additions.

Figure 29: FEU/Amalgamated FEI's Commercial Customer Additions



FEI does not forecast industrial customer additions and relies on customer surveys to determine throughput levels for the industrial sector.

7. ENERGY SUPPLY RISK

Supply risk relates to the physical availability of the commodity and the ability to reliably transport it using third party pipelines to FEI's system for delivery to end-use customers. Supply risk for gas utilities, broadly speaking, includes the possibility of supply interruption, which stems from the degree of reliance on a single supply basin, reliance on a single transportation pipeline, and the availability of regional storage. It also includes the timing and degree of long-term investment in developing and maintaining production, as well as adequate transportation pipeline capacity that is needed to bring production to market.

The analysis of supply risk is separated into two sections: (1) FEI's supply availability, that remains largely unchanged from 2012, and (2) security of supply risk, which has slightly increased compared to that of the benchmark utility in the pre-amalgamation period.

7.1 Availability of Supply

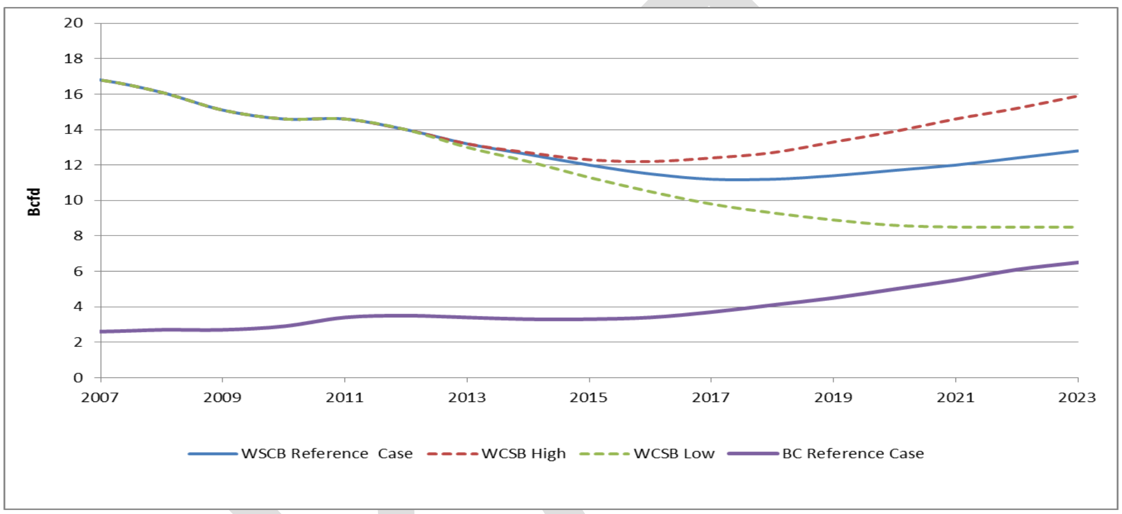
In the oil and gas industry, supply availability is typically separated into upstream activities, referred to as exploration and production (E&P) and midstream activities that include the storage and transportation of energy. Amalgamated FEI continues to source gas supplies from the same market hubs as prior to amalgamation. In addition, the integrated operation of the FEI, FEVI, and FEW transmission and distribution systems that existed before amalgamation means that amalgamation itself has had little impact on supply availability for FEI (FEVI and FEW were already connected to FEI's coastal transmission system, and FEVI's Mt. Hayes LNG facility was already used to balance gas supply in FEI's network).

In the next sections, upstream and mid-stream risks of FEI are analyzed in more detail.

Upstream Activities

FEI and other utilities in the U.S. PNW are generally supplied by natural gas that originates from the Western Canadian Sedimentary Basin (WCSB)[31]. Figure 30 illustrates the actual and forecast level of supply from the WCSB under three scenarios: a reference case, with baseline projections based on the current macroeconomic outlook, and two sensitivity cases assuming high and low prices to reflect the uncertainty around future energy prices.

Figure 30: WCSB Production (Actual and Forecast)



Source: NEB;"Canada's energy future 2013: energy supply and demand projections to 2035". November 2013.

As demonstrated in Figure -- the forecast for natural gas production indicates that production is expected to increase steadily after 2015/16 for the reference case to the end of the forecast period. This increase is dependent on rising prices and LNG exports supporting higher drilling levels. The large reserves of shale and tight gas located in NEBC will not however result in higher production levels unless and until there are markets for new production. Furthermore, the need for new markets for production from the WCSB has become critical as current production is being pushed from traditional markets in north-eastern North America. Traditional eastern markets for WCSB gas are becoming less dependent on WCSB gas because of the availability of and accessibility to a large volume of gas supply from large scale supply sources located in the northeast U.S., such as the Marcellus and Utica shale gas basins. In the future, existing production and increases from new producing areas in the WCSB will also be driven by increased regional demand, including industrial demand from oil sands development and expansion of gas-fired generation load in Alberta. LNG exports will develop if production can be cost effectively connected to overseas export markets.

[31] U.S. PNW utilities also access portion of their gas supply from Rockies basin in the United States.

Within the WCSB itself, the NEB foresees that the WCSB will continue to experience overall production growth, but rely increasingly on shale and tight gas and less on conventional natural gas production given its less attractive economic prospects. This production growth however, will only develop if the new markets for this supply grow large enough to offset the loss of traditional eastern markets. If this does not occur, then the natural gas located in large areas of the WCSB, and especially the significant resource located in the frontier areas of NEBC, will remain trapped. Should this outcome occur, it will be more difficult and costly in the future to secure the natural gas FEI requires.

Midstream (Transportation and Storage)

As described in the 2012 GCOC application, even under a production increase scenario in NEBC, there is still no guarantee that the incremental production levels lead to a more cost effective supply for FEI customers. Access and cost are affected by a variety of factors.

Amalgamated FEI continues to contract with third parties such as Spectra, Northwest Pipeline (NWP), and TransCanada's NOVA Gas Transmission Ltd. (NGTL) and FoothillsBC for transportation capacity in order to move supply purchased at different market supply hubs, and to complete withdrawals and injections from storage facilities, for delivery to its system. The Table 8 below provides a summary of FEI's main sources of supply as well as the related supply hubs. The FEI's supply sources have not changed since 2012 GCOC application.

Table 8: Summary of FEI's Main Sources of Gas Supply

Pipeline name	Supply Source	Main Hub	Level of importance
Spectra's Westcoast Energy Inc. (WEI)	NEBC	Station 2	Approximately 75% of FEI's gas is accessed via West Coast system. Also used for daily balancing via the Aitken Creek storage facility.
NGTL /FoothillsBC	Alberta	AECO/ NIT	Approximately 25% of FEI's gas is accessed via the NGTL and the FoothillsBC system from AECO/NIT. Also provides access to some storage capacity.
Northwest Pipeline	Washington; Oregon storage facilities	Sumas	Provides security of supply during winters and peak periods.

As indicated in Table 7, FEI remains heavily dependent on gas supply from NEBC that is transported on Spectra's WEI pipelines. There are a number of communities served by FEI in north-central BC that are entirely dependent on supply from WEI's T-South because there is no other infrastructure available for transporting natural gas to these locations. Outages or operational issues on WEI's system or in the producing regions can result in supply shortages on FEI's system.

FEI is in competition with utilities in Alberta and the U.S. PNW for storage and transmission capacity. Shorter duration market storage facilities are largely owned by utilities in the U.S. PNW and they have been utilizing an increasing share of those resources for their own use. In addition, the pipeline capacity to the Alberta marketplace from NEBC production has expanded considerably in the recent past, which provides optionality for producers to bypass the BC and Station 2 marketplace altogether.

Another critical factor regarding FEI's access to cost effective supply relates to regulatory proceedings in other jurisdictions. There are currently several NGTL and WEI infrastructure and rate design applications that either are or will soon be before the National Energy Board (NEB). The decisions regarding these applications could have an impact on the market in western Canada and impact FEI's supply procurement activities. Toll increases on pipelines and competition for BC gas supply from the Alberta marketplace, or Asian markets for LNG, could all put upward pressure on the cost of natural gas for customers in BC.

The NGTL North Montney Project proceeding is an appropriate example for further elaboration on this issue. Although the primary purpose of NGTL's project is to move gas produced in NEBC to serve the LNG export market, NGTL seeks to have the project considered an extension of its Alberta system, including the application of its toll methodology. Potential NEB approval of this toll methodology for the proposed facilities would impact FEI's ability to continue to access natural gas supply for its customers at fair market prices, reduce liquidity at the Station 2 hub and increase FEI's cost of holding firm transportation capacity and storage resources. Shippers that today flow gas on T-North and move gas to the Station 2 or Alberta market could alternatively simply bypass the WEI system. Any reduction in the use of T-North and T-South systems will increase the costs to their captive shippers such as FEI[32].

Due to recent regional market changes, there is a new supply risk to customers that rely on Spectra's Westcoast T-South system. New demand from projects either announced or being considered in the Lower Mainland and U.S. PNW have the capability of filling up long term T-South firm capacity.

A significant volume of gas supply serving industrial customers in the Lower Mainland uses the T-South system to flow on an interruptible basis, which means their gas supply is at risk of being cut as less uncontracted capacity is available. Any major decrease in the future availability of transportation capacity risks leaving these customers without adequate gas supply or they will need to pay significantly higher commodity prices at Huntingdon before any infrastructure expansions can be completed. Given that these industrial customers may not generally have sufficient credit to secure long term firm transportation capacity, and have not made a commitment to hold transportation capacity in the past, FEI faces the potential that these industrial customers will seek to

32 Progress is currently the largest T-North shipper on Westcoast. If Progress were to transfer those volumes to NGTL it could have a significant impact on the utilization and tolls of the T-North and T-South systems.

return to it for bundled service. If T-South transportation capacity is not available, then FEI risks not being able to serve transportation customers seeking to return to the utility for bundled service. Without available T-South transportation capacity these customers have no means of accessing the gas supply they require, which could result in a permanent decrease in FEI's system throughput and higher rates for remaining customers.

The supply risk to FEI's customers and other PNW utilities increases if new demand is added and there continues to be a lack of new pipeline transportation capacity. At this time, the only new industrial demand that is committed is 35 TJ/day for FEI's Tilbury LNG facility expansion project. The potential new loads from other potential projects are still pending, so in the short term the risks in terms of physical supply to meet the physical demand remains the same. However, if new load is added to the existing regional pipeline infrastructure, then supply constraints will increase FEI's throughput risk.

Jurisdictional Comparison

The supply and infrastructure for natural gas in BC is significantly different from the Alberta and Ontario marketplaces. The key differences relate to overall marketplace liquidity, the number of storage facilities and pipeline companies that operate in the Alberta and Ontario regions compared to BC. In addition, the amount of gas that flows in the Alberta/Ontario systems compared to BC is different.

The Alberta marketplace is a very liquid marketplace on a year round basis as it consists of a wide range of suppliers and resellers who are available on a daily basis to buyers. In addition, gas supply is readily available to buyers and sellers on an intraday basis each day in order to manage gas demand within a utility's operating region. The high level of gas flow in the Alberta market combined with a variety of available storage facilities provides gas supply to customers with no service disruptions in the event of gas plant outages. The close proximity of gas production to market and load centers also reduces the risk of gas supply disruptions for consumers. Although conventional Alberta gas production is declining, the availability of shale gas from BC coupled with significant increases in pipeline connectivity between BC and Alberta is anticipated to maintain the strength and liquidity of the Alberta marketplace.

The natural gas marketplace in Ontario is experiencing change whereby that region has started to benefit from shale gas supply located in close proximity to its operating region from basins such as the Marcellus and Utica. In addition, Ontario has historically benefited from sizable storage and deliverability within close proximity to load and market centers. Furthermore, the large Ontario gas utilities, Union Gas and Enbridge Gas, are owners and operators of the storage facilities in the area. Ontario's primary trading hub, the Dawn Hub, can access natural gas from the WCSB as well as a number of U.S. supply basins through a variety of pipelines feeding into the Dawn Hub. With the expansion of pipeline capacity, this hub will be able to readily access gas from the Marcellus region. Unlike the BC and PNW marketplace, where storage is limited, approximately 265 PJ of underground gas storage owned and operated by utilities also connect into the Dawn Hub providing substantial operational flexibility for the region. These differences compared with BC are important because they provide the Alberta and Ontario marketplaces with much more secure access to gas supply and are thus lower risk than the circumstances faced in BC.

7.2 Security of Supply

Security of supply relates to FEI's ability to provide gas supply to its core customers under extreme conditions and emergency situations. Compared to the situation as set out in the 2012 GCOC Application where the benchmark utility FEI did not include the Vancouver Island and Whistler service areas, amalgamated FEI's supply interruption risks have increased somewhat. The Vancouver Island and Whistler service areas are exposed to greater supply security risk than the Mainland.

- Both Vancouver Island and Whistler service areas are downstream of the mainland Coastal Transmission System. They are dependent on a pipeline system that traverses challenging terrain.
- Vancouver Island is supplied with three twinned submarine crossings ranging from 10.9 to 23.7 km in length. While the probability of a total failure of a submarine crossing is small, there is some additional risk associated with the difficulty of repairing a submarine crossing to maintain uninterrupted service once the gas supply in held in the Mt. Hayes LNG facility has been depleted.
- Whistler is served by the pipeline lateral between Squamish and Whistler, which faces single point of failure risk. Whistler also does not have any on-system storage facilities that can be used to maintain service in emergency situations.

8. OPERATING RISK

Operational risk can be defined as the physical risks to the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography and weather. FEI has addressed operating risks in this section with reference to:

- infrastructure integrity,
- third party damages, and
- unexpected events.

There have been no changes to the operating risk facing the facilities on the mainland since 2012. The addition of FEVI and FEW to the amalgamated FEI has had no material impact on the risk associated with infrastructure integrity, third party damages and unexpected events because the nature of the risk in all three cases is the same as on the mainland.

8.1 Infrastructure Integrity

Nearly a quarter of distribution mains and approximately a third of intermediate and transmission pressure pipelines have been in service for more than 45 years. A growing percentage of assets have been in service for more than 45 years. FEI anticipates that over the next 40 years approximately two-thirds of current assets will need to be replaced.

The operating risk presented by assets relates to the ability of service providers to respond to long-term utility infrastructure replacement programs. There are many variables impacting the useful life of underground pipe including pipe material, pipe coating, soil conditions, external interference, corrosion, etc. FEI has several programs in place to monitor, inspect and assess pipe condition and as a result of these assessments has developed longer term capital programs to replace sections of pipe that are reaching the end of their useful life. The primary challenges in terms of executing on infrastructure replacement plans are, firstly, in obtaining regulatory approvals, and secondly, in obtaining project resources to perform the work. These would include a mix of project managers and engineers, planners and field resources, etc. Other natural gas companies in the country as well as other utilities in the province (particularly BC Hydro) are competing for the same resources over similar time periods potentially driving up service provider costs.

As the trends were understood in 2012, the Company has assessed infrastructure integrity risk facing the amalgamated FEI to be similar to the risk facing the benchmark utility in 2012.

8.2 Third Party Damages

Third party damage refers to a third party either accidentally or deliberately damaging gas assets below ground or above ground. Below ground damage is usually caused by a contractor, municipality or homeowner excavating in the vicinity of gas infrastructure, following unsafe excavation practices and damaging the gas main, service line, or meter which may result in the loss of gas, service interruptions and significant repair costs. The number of incidents of third party damage has been on a decreasing trend since 2006. Deliberate third party damage (vandalism, theft, sabotage, terrorism, etc. usually in relation to above ground facilities) remains a relatively low frequency event in FEI in comparison to excavator third party damage. As this trend was understood in 2012, the Company has assessed third party damage risk facing the amalgamated FEI to be similar to the risk facing the benchmark utility in 2012.

8.3 Unexpected Events

Amalgamated FEI has a large radial system through river, watersheds, mountainous and forested terrain, which is subject to more hazards than operating a natural gas system on the prairies, for example. Natural events contributing to operating risk in BC include floods, washouts, forest fires, land slippage and earthquakes. While the timing of these events is somewhat unpredictable and cyclical in nature, FEI has systems in place to mitigate the impacts of these natural forces. In many cases, proactive emergency planning can further reduce the impacts of these events. However, given that the extent of these natural events remains unpredictable, they pose one of the higher operating risks to FEI.

The magnitude of this risk has not changed materially since 2012. The Vancouver Island and Whistler service areas traverse broadly similar topography and conditions to the Mainland.

9. POLITICAL RISK

Political risk can be defined as the potential for government to intervene directly in the utility regulatory process or negatively impact utility operations through policy, legislation and/or regulations relating to such issues as tax, energy and environmental policies, industry structure, safety regulations and Aboriginal Rights[33]. The political landscape is a significant risk factor for FEI.

Based on the above definition, the subsections below focus on climate change policies and legislation, GHG emissions reductions requirements, carbon tax, and aboriginal rights. Similar to 2012 the BC government's energy policies and legislation continue to discourage the use of natural gas in FEI's traditional markets (space and water heating) while promoting the new initiatives such as NGT and LNG export. Further local governments and municipalities have intensified their efforts to promote "green" initiatives that hinder the development of natural gas in space and water heating sectors. A new development since 2012 was the Supreme Court of Canada's ("SCC") 2014 Decision in *Tsilhqot'in Nation v. British Columbia,* which highlighted the risks faced by companies such as FEI with regards to Aboriginal issues. These developments are discussed in more detail in the following sections.

Another recent decision of the BC Court of Appeal *(Saik'uz First Nation and Stellat'en First Nation v. Rio Tinto Alcan Inc., April 15, 2015)* opens up the potential that First Nations pursue claims of impacts to Aboriginal Title as against non-governmental parties prior to actually proving Aboriginal Title.

All things considered, it is assessed that the amalgamated FEI's political risk is similar to the risk level identified in 2012 for the benchmark utility FEI.

9.1 Provincial Government's Energy Policies and Legislation

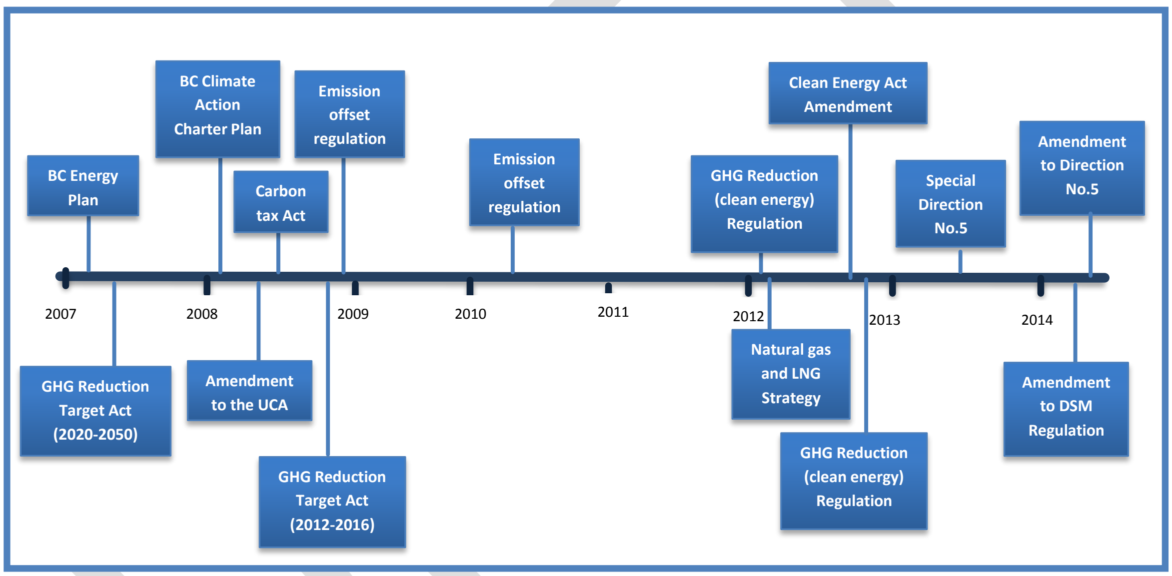
The BC government's energy policy and legislation has played a significant role in the risk assessment for FEI in the past. Similar to 2012, the role of natural gas in BC's Government energy policy continues to be focused on the role of natural gas in the transportation market and LNG export, as opposed to FEI's core business of space and water heating. FEI's core business will continue to be in the natural gas distribution for space and water heating for the foreseeable future, and it is within this market that FEI faces continuing challenges from policies and legislation that favour other energy sources.

[33] This is the definition provided by Ms.McShane in the last GCOC proceeding.

Since 2007, the BC provincial government has enacted a number of significant pieces of legislation in pursuit of its environmental and low carbon economy policies. These policies and related legislation have put substantial pressure on natural gas in its traditional role in providing heat for space and water heating, while creating some opportunities in non-traditional and less significant areas such as natural gas for transportation. The legislation includes ambitious greenhouse gas reduction targets, BC's Carbon Tax Act and the 2010 Clean Energy Act (CEA) which have focused on the role of clean and renewable energy, and energy conservation to meet the energy demands of the province, while at the same time reducing the competitiveness and ultimately the consumption of fossil fuels in BC.

Figure 31 provides a snapshot of all the recent energy and climate change policies and legislation developed in the Province, most of which were discussed in previous cost of capital proceedings[34].

Figure 31: Energy Policy and Legislation Timeline



Since the GCOC stage 1 filing, the BC government has introduced three new minor amendments to existing regulations and has issued a special direction to the BCUC for development of LNG facilities in BC. The three amendments are to the *Clean Energy Act* (CEA), the *Greenhouse Gas Reduction Regulation* (GGRR), and the *Demand-side Measures (DSM) Regulation*. Each of these developments are briefly discussed below. They do not represent a change in policy direction since 2012.

Amendment to the Clean Energy Act

In June 2012, BC's Energy Objectives Regulation modified[35] (in bold typeface) section 2(c) of the *CEA* to "generate at least 93 percent of the electricity in British Columbia,

[34] Please refer to 2009 ROE and capital structure proceeding as well as 2012 GCOC proceeding for detailed discussions.

other than electricity to serve demand from facilities that liquefy natural gas for export by ship, from clean or renewable resources and to build the infrastructure necessary to transmit that electricity." The change to the designation of natural gas as a source of clean energy for the purpose of LNG export enables production of electricity to fuel the LNG export market without compromising the requirements of the *CEA*. As a result, natural gas can be used for both liquefaction and as a power-generating fuel in LNG production, with the result of an increase in demand for natural gas in BC, and the potential for higher commodity prices. This amendment was giving effect to the BC LNG Strategy that had been discussed in the GCOC proceeding.

The power required for FEI's LNG facilities (Tilbury and Mt. Hayes), as well as the proposed Woodfibre LNG facility, is supplied by BC Hydro and therefore this amendment has no impact on natural gas demand in FEI's service territory in the short term.

Amendment to the Greenhouse Gas Reduction Regulation

On November 28, 2013, the BC government amended the GGRR to include mine haul trucks and locomotives as vehicles eligible for incentives, while increasing expenditure caps on items such as grants for safety practices or maintenance facilities, expenditures on stations and a tanker truck load-out facility. This amendment provides FEI with new opportunities in NGT markets; however, the market for the use of natural gas for locomotives and mine haul trucks is in its infancy and should have no significant impact on FEI's throughput in the short-term.

Amendment to the Demand-side Measures (DSM) Regulation

On July 10, 2014, the provincial government deposited BC Reg 141/2014 (the Amendment) which modified the prior *Demand-Side Measures Regulation*. The Amendment raised the low income program eligibility threshold and added a deemed list of eligible low income customers. Additionally, it changed the calculation of FEI's cost of energy for the modified total resource test. However, these changes do not result in an expansion of FEI's Energy Efficiency and Conservation spending and have no impact on FEI's risk profile.

Special Direction No. 5 to the BCUC

In November 2013, the BC Government issued BC Reg 245/2013, Special Direction No. 5 to the BCUC under Section 3 of the *UCA* (Direction No.5). Direction No.5, in its original form, exempted from review expenditures on an expansion of the Tilbury LNG facility up to $400 million, and effectively lowers the LNG dispensing rate to $4.35 per GJ. These developments represent a significant addition to rate base, which in isolation would place upward pressure on rates. It is expected, however, that the project will add throughput and generate counterbalancing benefits through the revenues from LNG sales. As the Tilbury LNG facility project is still in its early stages of development, FEI has assessed the project as currently having no material impact on the business risk of

[35] Deposited on July 25, 2012.

FEI Amalco, either favourable or unfavourable. Over the longer-term, the NGT and LNG market could help to mitigate rising business risk due to trends in the core business.

Amendments to Direction No.5 to BCUC

On December 22, 2014, the BC government deposited BC Reg 265/2014 (Order in Council No. 749) which amended Direction No.5. The amendment includes the following major components (each of which will be described in more detail below):

(i) Additional Expansion at Tilbury LNG facility (Phase 1B):

The Direction No. 5 amendments expand the Tilbury facility expansion project into two separate phases (1A and 1B) each of which is subject to a cap of $400 million plus AFUDC. Phase 1A is identified as the initial CPCN exemption of $400 million plus AFUDC for Tilbury LNG facility expansion project as defined in Direction No.5. Phase 1B includes an additional CPCN exemption for a second block of $400 million plus AFUDC for the Tilbury expansion project to provide additional liquefaction capacity (it does not include storage). The liquefaction capacity of Phase 1B must be 70 percent contracted (on average) over the first 15 years of operation before proceeding with construction. Contracts eligible for inclusion in the 70 percent average calculation must include take-or-pay obligations for at least 10 years and be 10 years or more in duration.

(ii) Rate Schedule (RS) 50 – Large Industrial Transportation Service Rate Schedule:

The amendment requires the BCUC to approve a new Rate Schedule (RS) 50, designed for large volume firm transportation service for large industrial customers. Among other things, the terms and conditions of this new RS include a minimum of 45 TJ firm daily demand and 15 year contract term. The RS 50 rate structure is designed to recover the costs of incremental capital investments required to serve RS 50 customers with incremental revenue providing additional contribution to existing natural gas rate payers that will offset the costs associated with the incremental capital.

(iii) Transmission project CPCN exemptions:

The amendment also exempts from the Commission's review the following transmission projects:

1. Coastal transmission system (CTS) capacity expansion projects: They include CPCN exemptions for the four Transmission pressure (TP) projects; namely three projects from the LMSU (Cape Horn to Coquitlam, Nichol to Port Mann, Nichol to Roebuck) and one on Tilbury Island to increase pipeline capacity into the LNG plant.

2. EGP Project: The Direction No.5 amendments further exempt from review, expenditures related to the potential EGP project.

(iv) FortisBC-BC Hydro Letter Agreement:

The FortisBC-BC Hydro letter agreement amends several agreements between BC Hydro and FEI and FEVI related to BC Hydro's capacity on the FEI and FEVI systems to deliver gas to Burrard Thermal and the Island Generation (IG) facility in Campbell River. The letter agreement deals with the BC Hydro's much-reduced need to transport gas across the FEI system after the impending permanent closure of Burrard Thermal takes place. After that occurs BC Hydro will only require transportation capacity to deliver gas to the Island Generation facility on Vancouver Island. In addition the letter agreement permits BC Hydro, under certain conditions to use its delivery capacity to deliver gas to the Woodfibre LNG facility if and when that facility goes into service.

9.2 GHG Emissions Reduction and Local Governments Initiatives

As has been the case for a number of years, BC continues to be at the forefront amongst those jurisdictions pursuing significant GHG reduction initiatives. The general implications of these policies for FEI's business risk remain consistent with FEI's characterization in the Stage 1 GCOC evidence. Local governments have also been assuming an increasingly important role in GHG emission reduction policy implementations and the codes and bylaws approved by these entities may have significant consequences on FEI's ability to attract new customers and retain existing ones (in some cases local governments have higher GHG emission reduction targets than the provincial government).

The measures put in place in BC, which include a focus on reducing the use of natural gas in heating applications, has a disproportionate impact on BC natural gas utilities. Each of the four provinces examined has instituted various measures to reduce GHG emissions within its jurisdiction. Table 9 shows GHG emissions reduction targets in British Columbia, Alberta, Ontario and Quebec. Compared to 2012, these targets have remained unchanged.

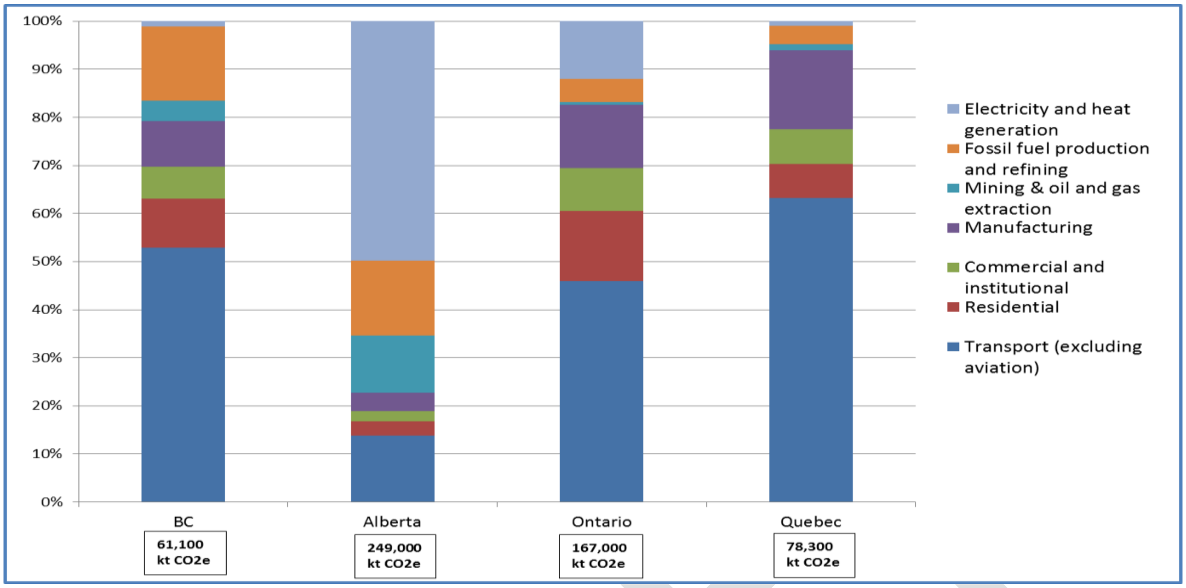
Table 9: GHG Emissions Reduction Targets in Four Jurisdictions across Canada

Province	GHG Emissions Reduction Targets
British Columbia	Reduce by 33% below 2007 level by 2020 Reduce by 80% below 2007 level by 2050
Alberta	Reduce by 50 megatonnes below business as usual by 2020 Reduce by 200 megatonnes below business as usual by 2050 (Reduce by 14% below 2005 levels by 2050)
Ontario	Reduce by 15% below 1990 levels by 2020 Reduce by 80% below 1990 levels by 2050
Quebec	Reduce by 20% below 1990 levels by 2020

Source : Environment Canada, 2014; Canada's Emission Trends

Furthermore, as Figure 32 demonstrates, the GHG emissions profile of each province is significantly different from the others.

Figure 32: GHG Emissions Profile for Major Energy Sector Categories Across Four Jurisdictions in Canada* (2012)



Source: Environment Canada National Inventory Report 1990-2012 data
* The values in boxes underneath each column represent the total GHG emissions in all sectors for 2012 rather than just the major selected categories included in the columns

Differences among the provinces in their GHG emissions profile can lead to different GHG emissions reduction solutions within each province. For instance, as demonstrated, close to 50 percent of Alberta's GHG emissions are related to power and heat generation which is caused by Alberta's traditional reliance on coal fired plants. This implies that a shift from coal to natural gas for electricity generation in Alberta will have the effect of reducing GHGs from electricity generation. On the other hand, in provinces such as British Columbia and Quebec with abundant hydro resources available, the GHG emissions in power and heat production sector are minimal and therefore in order to achieve the GHG emission targets the government must target other areas such as the transportation sector as well as the residential and commercial sectors.

Furthermore, legislation continues to require all BC local governments to set GHG reduction targets at the municipal and regional district level. The majority of BC's local governments have signed the Climate Action Charter, pledging to take action to significantly cut both corporate and community-wide greenhouse gas emissions. Local governments can achieve carbon neutrality by reducing emissions, by purchasing carbon offsets to compensate for their greenhouse gas emissions or by developing projects to offset emissions. Such projects may include improving the energy efficiency of local government-owned and operated buildings and vehicle fleets[36].

On September 24, 2008, the Province announced the Climate Action Revenue Incentive Program (CARIP) to offset the carbon tax for local governments who have signed the

[36] http://www.cscd.gov.bc.ca/lgd/greencommunities/climate_action_charter.htm.

B.C. Climate Action Charter. To be eligible for the program, municipalities will be required to report annually on the steps they are taking – and progress they have made – to become carbon neutral.

Based on a review of the corporate and community-wide actions[37] reported over 2010, 2011 and 2012, some overall trends regarding local governments' corporate and community-wide effort reduction efforts have emerged[38]. For instance, on the corporate side, the "building and lighting" category has encompassed over one third of the total direct actions[39] throughout the three reporting years. Further, on community-wide efforts, policy development actions such as update of building codes for emission reductions have been at the forefront of the "supportive actions"[40] taken by municipalities. The table below presents some of the types of actions in each of these major categories for corporate and community-wide efforts.

Table 10: Examples of GHG Reduction Direct and Supportive Actions Reported in Corporate and Community-Wide Spheres

	Community-Wide	Corporate
Direct Actions	Use of sustainability checklists for new buildings, Grants for improved residential energy efficiency, District energy and energy exchange systems, Geothermal, …	building retrofits to improve heating efficiency, …
Supportive Actions	Revised Official Community Plans (OCPs) to include GHG reduction targets, policies and actions, Development of Climate Action Plans, Community Energy and Emissions Plans, Development of policies related to buildings, transportation and waste (e.g. green building strategies), …	corporate climate action plans, corporate building policies, corporate fleet and energy use policies, …

The trends seen over the past number of years have solidified. Municipalities are making significant changes to their operations, policy, codes and regulations, which are having a direct negative impact on natural gas throughput. For instance:

- As part of the City of Vancouver's "Greenest City 2020 Action Plan", it is required that all new larger buildings – specifically, buildings classified in the building Bylaw as Part 3 and Part 9 non-residential buildings –be designed to strict

[37] Local government corporate actions refer to efforts by local governments to reduce their own emissions. Overall, through the purchase of offsets and by undertaking measurable emission reduction projects, in 2012 BC local governments reduced their reported corporate greenhouse gas emissions by over 91,000 tonnes. Community-wide actions refer to the efforts that require the support of the greater community.

[38] http://www.cscd.gov.bc.ca/lgd/library/CARIP_2012_Summary_Report.pdf.

[39] Direct actions are those that can be directly implemented and the impacts directly measured (e.g. installation of an energy efficient heating system).

[40] Supportive actions provide the framework to support implementation of direct action (e.g. development of policies, education programs, feasibility exploration). For clarity, the designation is not FEI's assessment of whether or not these initiatives are helpful or detrimental to its business.

energy standards. Energy reduction targets for new buildings are 20 percent below 2007 levels by 2020, and “carbon neutral” by 2030. The City also introduced Canada’s first energy code/bylaw for existing larger buildings classified as Part 3 and Part 9 non-residential. The 2020 energy reduction target for existing larger buildings is to reduce greenhouse gas emissions to 20 percent below 2007 levels[41].

- Further, under the City of Vancouver’s “Green Home Program”, new one and two-family homes are required to include a number of sustainable features that are focused on energy savings up to 33 percent by the year 2020. It is projected that the Vancouver Green Homes Program will be 14 percent more effective in reducing GHG’s in new dwellings than what has recently been introduced in the Provincial Building Code. For instance, the 2014 amendments to the Vancouver Building Bylaw include a number of new requirements for increasing natural gas fireplace efficiency through electronic ignition and direct-ventilation which directly affect natural gas consumption.[42] The recent amendments to Vancouver’s by-law also mandates that for the boiler or furnace upgrades of over $5000, the annual fuel utilization efficiency (AFUE) shall be equal or more than 90 percent. The AFUE of 90 percent requires a condensing system. Generally speaking with old homes, it is expensive to convert the existing venting system to accommodate the venting system that is required for a condensing unit which can lead to a migration of existing customers from natural gas condensing boiler/furnaces to electric ones.

- The recent amendment to the City of Richmond bylaws (amendment bylaw 9147) requires that new townhouses be designed (a) to score 82 or higher on the EnerGuide Rating System (this is higher than the EnerGuide score of 77 that is currently required by the BC Building Code) and (b) be solar hot water-ready. Alternatively, new townhouses will be exempt from the above if they connect to a district energy utility or install industry proven renewable energy systems (such as geo-exchange, solar water heating, photovoltaic energy) which provide the majority (at least 51 percent) of heating, cooling and/or electrical energy load requirements[43].

- In 2012, Surrey City Council approved the District Energy System By-law which includes the requirement for all City Centre developments of a certain size to be fully compatible for district energy connection. Most recently, Council approved the Policy on Utility Rate Setting and Regulation which sets out the principles and methodology by which customer rates will be established and regulated by

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41 http://vancouver.ca/home-property-development/large-building-energy-requirements-forms-checklists.aspx.
42 http://vancouver.ca/files/cov/green-homes-council-report.pdf.
43 http://www.richmond.ca/__shared/assets/_2_OCPAmendment_EnergyEfficiency39053.pdf.

Council. The City's new City Hall and City Centre Library are already serviced by a new geo-exchange system. In addition, the City's district energy utility, Surrey City Energy, is preparing to begin construction of new thermal energy plants and associated distribution piping in order to provide thermal energy for the various developments currently planned and under construction in the City Centre.

Similar programs can be found in most of the municipalities that have signed the Climate Action Charter. These actions by local governments promote moving away from natural gas (as the business as usual energy source) to other energy sources. They also encourage conservation and efficiency, which negatively impacts demand for natural gas (other things being equal).

In recent years, environmentalist and anti-pipeline activists have increased pressure on companies involved in BC's pipeline and LNG projects. These movements seek to influence public policy and the actions of government bodies, and can impede infrastructure projects. The focus to date has been on oil and LNG infrastructure; however, activism of this nature poses an increasing risk for FEI, primarily because FEI is entering a phase of significant infrastructure development and renewal.

9.3 Carbon Tax

The carbon tax is an example of legislative or political action that has had direct implications for the price competitiveness of natural gas as an energy source in BC. The essential features of BC's carbon tax have remained unchanged since the 2012 proceeding.

The following objectives are stated by the BC Government for implementation of carbon tax[44]:

- to encourage individuals, businesses, industry and others to use less fossil fuel and reduce their greenhouse gas emissions;
- to send a consistent price signal;
- to ensure those who produce emissions pay for them; and
- to make clean energy alternatives more attractive

As shown in Table 11, British Columbia and Quebec are the only two provinces in Canada that have implemented carbon tax policies on fossil fuels; however, British Columbia has a significantly higher carbon tax rate than Quebec. The BC carbon tax increased from $0.50 per GJ in 2008 to $1.49/GJ in 2012, where it has remained. This

[44] http://www.fin.gov.bc.ca/tbs/tp/climate/carbon_tax.htm.

increase in carbon tax since 2008 partly offset the decline in natural gas commodity prices over the same period.

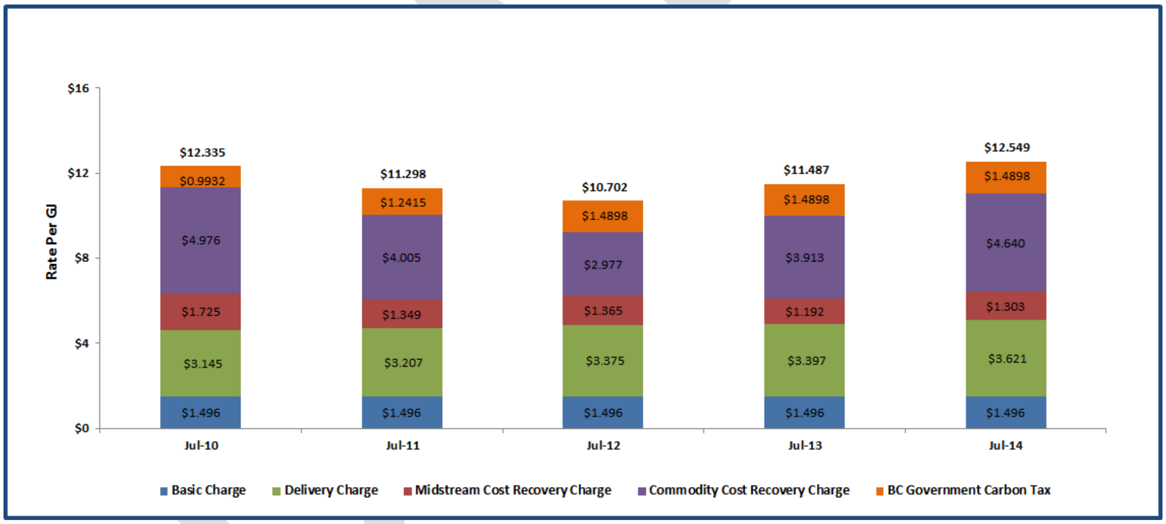
Table 11: Provincial Carbon Tax Rate

Province	Start Date	Carbon Tax Rate
British Columbia	2008	$10 per metric ton of CO2e emissions in 2008, increasing $5 annually to $30 in 2012
Quebec	2007	$3.50 per metric ton of CO2e emissions

Source: National Renewable Energy Laboratory

The carbon tax represents a competitive challenge for FEI as it is a discrete tax applicable to natural gas and other fossil fuels, but not to electricity (despite the fact that some of the electricity that is consumed in BC is generated by fossil fuels in neighboring jurisdictions). Figure 33 provides a historical look at gas prices from July 2010 to July 2014 for FEI Rate Schedule 1 customers in the Lower Mainland, which breaks out the carbon tax component.

Figure 33: Non-amalgamated FEI Lower Mainland Annual Residential Bill History (Rate Schedule 1)



Although no further carbon tax changes have been announced since the current rate took effect in 2012, the potential for carbon tax increases and the level of tax remain unknown at this time. The Government has stated that as other jurisdictions, especially within North America, introduce similar carbon taxes or carbon pricing, Government may again review and consider changes to the carbon tax. In the meantime, the competitive impacts of the carbon tax persist.

9.4 Aboriginal Rights and Title

FEI faces an elevated level of business risk related to relationships with First Nations in British Columbia relative to what existed at the time of the GCOC proceeding.

First Nations in British Columbia

Since FEI's activities span large parts of British Columbia, the Company comes in contact with a large number of aboriginal groups in British Columbia.

Aboriginal and treaty rights are expressly recognized and affirmed by section 35 of the Constitution Act, 1982. This poses risk to all utilities in Canada. However, two main factors differentiate BC from elsewhere:

1. First, there is a larger number of First Nations in BC compared to the rest of Canada. British Columbia recognizes 285 different First Nations, Bands and Tribal Councils, which is over one-third of all Aboriginal groups recognized in Canada.

2. Second, most First Nations in BC are not signatories or adherents to a treaty (historic or modern) and most land in British Columbia is not covered by a treaty, unlike in most other provinces. Treaties assist in delineating rights of the signatory First Nations. As a result, many First Nations in British Columbia hold outstanding claims to Aboriginal title and rights. In addition, there can be competing claims from different First Nations over the same piece of land, necessitating that utilities deal with multiple First Nations in respect of specific assets.

In contrast, all of the land in Ontario and Alberta is covered by treaties, as well as most of the land in Quebec. Each of those provinces recognizes far fewer aboriginal groups, most of which are signatories to treaties.

The area of aboriginal law is evolving, with new cases being heard by the courts on a regular basis that have potential implications for anyone proposing activities that may impact asserted Aboriginal rights or title, including FEI. Developments in case law have had, and may in the future have, a bearing on FEI's business by influencing Government policy and processes of permitting authorities.

The Crown has a constitutional duty to consult and, if appropriate, to accommodate unproven Aboriginal rights and title that are asserted by Aboriginal groups. In the majority of cases, the procedural aspects – that is, the actual on-the-ground work of information sharing, learning about the potential impacts and the planning for mitigation - is delegated to the project proponent. However, the duty rests ultimately with the Crown, and FEI is dependent on the Crown's level of commitment to fulfil its duty. The project proponent (FEI) is affected by the pace and nature of any dealings between the Crown and the First Nation, and any court decision that halts a project for lack of adequate consultation.

Aboriginal law issues are not new to FEI. FEI conducts its business in a manner influenced by, and in accordance with Aboriginal law. However, the recent SCC Decision in *Tsilhqot'in Nation v. British Columbia*, 2014 SCC 44 increases FEI's business risk. It has done so by emboldening Aboriginal groups and creating some uncertainty through several passages.

The *Tsilhqot'in* decision of the SCC represents the first time that a Canadian court has determined that Aboriginal title exists in respect of a particular tract of land. This has particular relevance in British Columbia where most land is subject to title claims by Aboriginal groups.

Where Aboriginal title has been established, the Crown must not only comply with its constitutional consultation obligation but also ensure that the proposed government action is consistent with Aboriginal title. Governments can only infringe proven Aboriginal title with consent of the title holder or, by meeting the established test for "justification". Prior to the establishment of title, the obligation on the Crown remains to consult and potentially accommodate Aboriginal groups asserting title. However, the SCC created some uncertainty by also stating (at para. 92) "if the Crown begins a project without consent prior to Aboriginal title being established, it may be required to cancel the project upon establishment of the title if continuation of the project would be unjustifiably infringing". These comments from the SCC have been interpreted broadly by First Nations as applying to facilities and projects that are already constructed and in place on lands subject to a declaration of Aboriginal title. The intent of these passages will likely be the subject of future litigation and interpretation.

The uncertainty described above together with differing views on the scope of adequate consultation and accommodation creates operational and regulatory complexity in British Columbia and a risk of litigation that is greater than other areas in Canada, and greater than it was in 2012.

The other notable development since 2012 has been the amalgamation of the FortisBC Energy Utilities. FEI has not attributed any increase in business risk to the amalgamation *per se* but it is relevant to note that with amalgamation fourteen First Nations located in the Vancouver Island and Whistler service areas have been added to FEI's service territory.

10. REGULATORY RISK

The degree to which FEI, as a regulated public utility, is dependent on the Commission for timely and fair approvals to earn its return on and of capital results in what FEI refers to in this section as regulatory risk. Although PBR has introduced additional risk in some respects, the broader regulatory constructs that supported FEI's characterization of regulatory risk in 2012 remain in place. FEI has thus assessed its overall regulatory risk as being similar to what it was in 2012 with the potential to be higher over the term of the PBR.

10.1 Uncertainty and Lag in Regulatory Approval

As a regulated public utility, FEI can only construct significant utility assets with a CPCN approval. It can only charge rates that have been approved by the Commission. The Commission sets the allowed return on equity and capital structure of the utility, and assesses depreciation rates that permit recovery of invested capital. The Commission, as a statutory entity, acts pursuant to its power under the *UCA* but within that framework has significant discretion in the exercise of those powers. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty. Regulatory oversight gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that does not provide FEI with an opportunity to earn its fair return on and of capital, or that necessary investments are not approved.

Regulatory Uncertainty

Regulatory uncertainty can be defined in different ways[45]. However for the sake of conciseness and for the purpose of this Application, FEI only considers the following three types of uncertainties:

1. Uncertainty raised due to the unpredictability of future decisions of the current regulator (and its successors) which may be exacerbated by regulatory inconsistency;

2. Uncertainty caused by vague decisions that are open to interpretation by the regulator (and its successors); and

3. Uncertainty regarding the future implications of the regulator's decisions.

The determinations regarding cost of capital have a direct and significant impact on FEI's ability to earn a return on and of its invested capital that meets the Fair Return Standard. In the GCOC Stage 1 Decision the Commission acknowledged that the "*BC regulatory framework has a significant influence on FEI's business and that individual decisions can have significant implications for FEI*.[46]"

The PBR Decision exemplifies how an individual Commission decision can have implications for FEI's ability to earn its fair return. Compared to cost of service regulation, performance-based rate-setting is subject to some additional risk associated with managing the controllable costs over a longer time horizon to a formulaic amount. This is particularly the case when the determined productivity improvement factor of the formula is higher than inflation and the expected industry productivity levels and therefore represents a risk to the balance between service quality, operating costs and capital costs under the PBR plan. In addition to this general risk inherent in all PBR plans, there are other specific aspects of the PBR Decision that have the potential to elevate regulatory risk for FEI during the pendency of the PBR term:

- Reduction of FEI's growth factors by 50 percent: A major shift from previous PBR decisions in BC and other Canadian jurisdictions relates to the 50 percent reduction of growth factors in the PBR formulas. Considering that this is a new approach to PBR design in Canada and also in light of the fact that the

[45] For a comprehensive review of the definitions and taxonomy of regulatory risk please refer to the paper by Bastian Schwark titled "Influence of regulatory uncertainty on capacity investments – Are investments in new technologies a risk mitigation measure?", Retrieved from: http://infoscience.epfl.ch/record/153004/files/15d_schwark_paper.pdf.

[46] BCUC GCOC Stage-1 Decision, p.40.

determination of a 50 percent reduction was subjective, the effect of this change may only be known after the pendency of the PBR term. This is particularly important for the PBR formula related to capital expenditures for service line additions, where the relationship between service line additions and spending is relatively linear and therefore the growth factor reduction may be considered a form of cost disallowance of prudently incurred costs.

- Potential disallowance of prudently incurred costs for exogenous events: The determination of the materiality threshold for exogenous events is another example of inconsistency between 2014 PBR Decision and FEI's extensive history with PBR design. As explained in responses to information requests and discussed during the oral hearing, a materiality limit gives rise to the potential for denial of prudently incurred costs and increases the underlying risk to the Companies.

- Backward-looking vs. forward-looking rate-setting elements of the PBR formula: Despite acknowledging some of FEI's reasoning for forecasting the formula drivers, the Commission determined that the inflation and growth factors of the PBR formula should be set based on backward looking historical data. This is analogous to cost of service regulation using a historical test year rather than a future test year. Forward test years have been a fundamental element of BC's regulatory framework and PBR formulas have always been determined based on forecast data. The Commission's decision to distance from this principle introduces some additional regulatory uncertainty.

- The PBR Decision replaced a number of important and long-standing deferral accounts with one more comprehensive deferral mechanisms that is only approved for the term of the PBR plan. This raises the prospect of how these costs will be treated when FEI emerges from PBR term.

Regulatory Lag

Regulatory lag is defined as a delay between incurring a cost and the implementation of the rates that recover these costs. The growing complexity of FEI's operating environment can also lead to delays (regulatory lag) in system investments, or the delivery of service offerings. Regulatory lag can present a risk for FEI's return on and of capital.

One aspect of regulatory lag is the time between application filings and final approvals. Given the complexity of the regulatory process, there is going to be an inherent delay between the time an application is filed and the final order related to that application. While the need to conduct regulatory reviews of utility operations is an integral part of being a public utility, the resulting delay does create risk for the utility. Risk arises in part because it is necessary for the utility to conduct its operations based on interim rates, with no assurance that the interim rate will be confirmed in the final decision, or that the projects contemplated and required to be undertaken will ultimately be approved.

Significant regulatory processes for FEI applications have recently been lengthy, resulting in extensive periods during which the utility is operating on interim rates. For instance, FEI's 2014 PBR application was filed in June 2013 while the Commission's Decision was released in mid-September 2014, clarification of certain items was not received until mid-October and a reconsideration of one component was received in February 2015. This 15+ month regulatory lag period is much longer than the regulatory lag period for previous PBR proceedings. Three quarters of the first test year was finished before FEI was aware of the approximate final rates for 2014, making execution of capital plans and setting of O&M targets challenging.

10.2 Deferral Accounts

Deferral accounts can help to reduce the rate impact and rate volatility for customers. The Commission determined in the 2009 ROE Decision that "…the effect of deferral accounts in reducing the risk of [FEI] as reducing the short-term, and not the long-term, business risk of [FEI]...".[47]

The majority of FEI's deferral accounts have been put in place to ensure forecast variances do not result in costs being inappropriately borne by customers or the Company. In the recent PBR Decision, the Commission directed FEI to discontinue the usage of a number of deferral accounts;[48] however, the discontinuance did not, in and of itself, materially change FEI's short-term risk profile since the Commission also directed FEI to true-up those costs each year through a flow-through mechanism[49] for the term of the PBR. The rest of key deferral accounts remained unchanged. The discontinuation of long-standing deferral accounts in favour of PBR specific mechanism has increased regulatory risk over the longer term because it is unknown how these costs will be addressed once FEI emerges from PBR. Table 12 summarizes the general categories of FEI's deferral accounts.

[47] Order No. G-158-09, page 19.

[48] Tax variance deferral account, the property tax variance deferral account, the insurance expense variance deferral account and the interest expense variance deferral account.

[49] The flow-through deferral account also include items such as interest expense related to changes in debt balances, customer variances for residential and commercial customers as well as the industrial margin variance.

Table 12: Deferral Accounts

Deferral Account Category	General Purpose & Description
Margin Related	• Decreasing the volatility in rates caused by such factors as fluctuations in commodity prices and the significant impacts of weather on use rates • Deferring the cost of gas and delivery margin impacts arising from un-forecast variations in these types of factors and recovering them from/refunding them to customers over a longer period of time to reduce rate volatility <u>Examples:</u> Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (MCRA) and Revenue Stabilization Adjustment Mechanism (RSAM)
Energy Policy	• Capturing costs associated with changing energy policies that focus on energy efficiency, conservation and the environment • Deferring and amortizing these costs matches the costs of the programs with a reasonable period of time over which the benefits are expected to be realized by customers <u>Examples:</u> Energy Efficiency and Conservation Account (EEC), Compliance with Emissions Regulations, NGV Incentives
Non-Controllable Items	• Items which are either outside of the Company's control or where the Company has limited ability to influence the costs • Deferring the variances from the forecast level of costs for these activities reduces the exposure for both the Utility and customers due to significant variances in these amounts, and serves to avoid windfall gains or losses to the Company or to customers <u>Examples:</u> Flow-through deferral account, Pension and OPEB Variances, BCUC Levies Variance
Costs of BCUC Applications	• Captures costs required to support regulatory applications, such as intervener and participant funding costs, Commission costs, costs for expert witnesses and consultants, costs related to independent validation of study results, legal fees, required public notifications, and miscellaneous other costs <u>Example:</u> 2014–2019 PBR Application Costs deferral account
Other	• Various accounts that provide benefits to customers and the Company, often for items that are non-recurring in nature <u>Examples:</u> Whistler Pipeline and Conversion Costs, BCOneCall Project, Gas Asset Records Project

10.3 Administrative Penalties

On May 31, 2012, Bill 30 – *Energy and Mines Statutes Amendment Act, 2012* – received Royal Assent. Bill 30 amends several statutes, including the *Clean Energy Act*, *Oil and Gas Activities Act* (*OGAA*) and *UCA*. In the GCOC proceeding, FEI had identified the new administrative penalties as a change in its regulatory environment since 2009. There has been no change in status of administrative penalty framework since its implementation. FEI also recognizes that administrative penalties can only be issued if FEI is found to have breached legislation or a Commission order. This discussion is included for the sake of completeness only, and FEI has not assessed any change in business risk associated with administrative penalties.

FEI and FBC 2014-2018 PBR Decision Summary
PBR 2014-2019 Plan

PBR Plan Elements:

- Term:
    - Applied for 5 years (2014-2018); Approved 6 years (2014-2019) given late Decision

- O&M and Capital Formula Calculation Components:
- I-Factor:
    - Weighting of 55% labour using BC AWE index/45% non labour using CPI (as applied for)
    - Use actual index results of the previous year (applied to use forecast)
- X-Factors:
    - Following X-Factors approved (applied for 0.5% for FBC and FEI):

Utility	TFP	Stretch Factor	X-Factor
FBC	0.93	0.1	1.03
FEI	0.90	0.2	1.10

- Growth Factor:
    - Formula only incorporates half of customer growth (applied for 100% of growth)
    - Calculation is prior year actual customer adds/two year prior customer adds (applied to use forecast)

- Exogenous Factors
    - Commission imposed criteria on qualifying for exogenous factor treatment
    - Primary qualification is Costs/Savings for a single event must exceed the Commission-defined materiality threshold of 0.5% of each companies 2013 Base O&M (approx. $1.1M for FEI and $300K for FBC)

- Earnings Sharing Mechanism (ESM):
    - Approved as filed – 50/50 symmetric sharing for earnings above or below the approved ROE
    - Can be impacted by failure to meet SQIs (see SQI section below)

- Earnings Carryover Mechanism (ECM):
    - Denied
    - Fortis can apply, on a case-by-case basis, for approval of an ECM initiative

- Off-Ramps:
    - Financial Triggers:
        - Earnings in any one year varies from approved ROE by more than +/- 200 bps (post sharing)
        - Earnings vary from approved ROE by more than +/- 150 bps (post sharing) in two consecutive years

- Non-Financial Triggers to be finalized in consultation with stakeholders

- <u>Deadband for Capital Formula:</u>
  - 10% deadband approved as applied for
  - Additional criteria of a 15% deadband for two years cumulative

- <u>Exclusions from the Capital Formula:</u>
  - For 2014 and 2015, exclude CPCNs from the formula
  - Process to determine what is excluded for subsequent years, and also discuss appropriateness of current CPCN thresholds

- <u>Annual/Mid-term Review:</u>
  - More extensive Annual Review process is necessary with a list of items
  - No requirement for mid-term review

- <u>SQIs</u>
  - Approved as filed except that informational SQIs require benchmarks – benchmark will be three year average 2010 to 2012
  - Added SQIs (2 gas and 3 electric) that will be informational only
  - Increased Emergency Response benchmark
  - Penalty for not achieving SQI within a range (Maximum penalty a reduction of ESM to 40% shareholder/60% customer)
  - Process to work with stakeholders to determine the acceptable range

O&M Base:

- FEI reduced by $1M for vacancies, $1.034M for high carbon fuel switching, $600K for LTRP, $120K for biomethane program manager (transferred to BVA), $50K for political donations, and an amount to be calculated for a portion of executive STIP to be borne by the shareholder
- FBC reduced by $200K for vacancies, and also the executive STIP
- FBC base increased by $140K for insurance expense not related to premiums (reclassification only between base and flow-through)
- Increase base for both gas and electric for denial of the capitalization of software upgrade costs ($1.8M in FEI and undetermined in FBC)

Capital Base:

- Approved as filed

FEI and FBC 2014-2018 PBR Decision Summary
PBR 2014-2019 Plan

Demand Forecast

- Approved as filed except FEI RS 22 which is to be increased by 21%

Deferral Accounts:

- Specific accounts denied but actuals to be flowed through each year
- Other accounts generally approved except as follows:
  - The change in amortization of pension/OPEB variances to EARSL from 3 years
  - Biomethane costs to go to the BVA
  - FEI Asset loss deferral to be discontinued with 10 year amortization of balance (revert to prior treatment which aligns with FBC)
  - WACC return denied for FBC only but further submissions
  - FBC Rate stabilization (RSDM) approved only as it related to WAX CAPA loss

Accounting Changes:

- All approved except:
  - Capitalization of software upgrade costs (discussed above)
  - Capitalized overhead rates will now be 12% for gas (currently 14%) and 15% for electric (currently 20%)
- Corporate and shared services approved as applied for
- Uniform System of Accounts to be adopted by FEI for O&M starting 2016
- Non rate base deferrals for FEI to be included in financial schedules

EEC/DSM:

- Amounts and accounting treatment approved as requested except the FBC DSM deferral 10 year amortization instead of 15
- Deny FEU's request to place the actual expenditures from PWC's administration of EEC funds for projects with a thermal energy component in the EEC non-rate base deferral account that attracts AFUDC
- Other details available in a separate document

Compliance/Future Filing Requirements:

- Calculation of Materiality threshold for Exogenous Factors (0.5% of 2013 calculated Base O&M)
- FBC update flow-through expenses so that only Insurance Premiums are included in the Insurance Expense flow-through
- FEVI/FEW adjustments to O&M and capital base filed within 60 days
- Consultation process with stakeholders on SQI ranges
- FEI mechanism for RS22 demand forecasting

- FBC explanation as to why the historic load information from the City of Kelowna for past years is unavailable
- Requirements re biomethane cost details
- Executive STIP amounts spent vs. target

Future Filing Requirements:

- TFP Benchmarking Study – (after consultation with parties and Commission staff regarding engaging a mutually acceptable consultant, and reporting to Commission staff) FEI and FBC each to prepare a benchmarking study to be completed no later than December 31, 2018

Rating Report

FortisBC Energy Inc.

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DBRS

Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
MTNs & Unsecured Debentures	A	Confirmed	Stable
Purchase Money Mortgages	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On January 6, 2015, DBRS Limited (DBRS) confirmed the Issuer Rating as well as the MTNs & Unsecured Debentures and Purchase Money Mortgages ratings of FortisBC Energy Inc. (FEI or the Company) at "A" and its Commercial Paper rating at R-1 (low). All trends are Stable. The rating confirmation follows the completion of the amalgamation of FEI, FortisBC Energy (Vancouver Island) Inc. (FEVI), FortisBC Energy (Whistler) Inc. (FEW) and Terasen Gas Holdings Inc. (the Amalgamation) on December 31, 2014. The amalgamated entity is known as FortisBC Energy Inc. (FEI). The confirmation is based on DBRS's view that the Amalgamation will not have a material impact on FEI's credit profile, reflecting the following factors:

(1) The business risk profile of the amalgamated entity would not be materially different from FEI's pre-amalgamation business risk level. The amalgamated entity will have a larger customer base than FEI's pre-amalgamation customer base, and the risk previously attributable to FEVI's and FEW's competitive position and smaller size is eliminated.

(2) The British Columbia Utilities Commission (BCUC) has approved the adoption of common rates to be phased in over a three-year period for natural gas delivery to all customers of the amalgamated entity except those in the Fort Nelson, British Columbia, service area.

(3) The BCUC issued its decision on FEI's multi-year Performance Based Ratemaking Plan Application in September 2014 (the multi-year PBR). The term of the multi-year PBR was extended to 2019. The multi-year PBR incorporates a mechanism for improving operating efficiencies, with operation and maintenance costs as well as base capital expenditures (capex) being subject to a formula during the PBR period. The BCUC also approved a 50/50 sharing of variances from the formula-driven expenditures over the PBR period.

(4) Starting in 2015, the new amalgamated entity will have a return on equity (ROE) of 8.75% and a deemed equity component of the capital structure of 38.5%, which is unchanged from 2014 for FEI. As a result, FEI's financial metrics are expected to remain within DBRS's "A" rating guidelines.

Financial Information (DOES NOT RECOGNIZE THE RETROACTIVE EFFECT OF THE AMALGAMATION)

FortisBC Energy Inc.	9 months	9 months	12 months	For the year ended December 31st		
(CA$ millions)	**Sep. 30. 14**	**Sep. 30. 13**	**Sep. 30. 14**	**2013**	**2012**	**2011**
EBIT gross interest coverage 1	1.82	1.74	2.05	1.99	2.03	2.08
% debt in capital structure 1	61.4%	59.7%	61.4%	60.3%	58.9%	62.6%
Cash flow/Total debt	12.9%	12.9%	14.3%	14.3%	13.9%	11.1%
Cash flow/Capex	1.20	1.66	1.27	1.58	1.49	1.14
Net income before extra. items	59	57	106	104	112	110
Cash flow from operations	177	166	262	251	237	193

1 Adjusted for operating leases.

Issuer Description

FortisBC Energy Inc. (FEI or the Company) is the largest natural gas distributor in British Columbia, serving approximately 960,000 customers. The Company is a 100% indirectly owned subsidiary of Fortis Inc. (rated A (low)).

Rating Considerations

Strengths

1. Relatively low business risk.
FEI's business risk is viewed as relatively low, supported by the following factors: (a) FEI generates virtually all of its earnings from its regulated natural gas distribution and transportation operations, where competition is limited to other forms of energy (electricity); (b) FEI is not exposed to commodity price risk, as natural gas costs are passed on to the customers, with adjustments made through quarterly review and application to the BCUC; and (c) volatility in usage by residential and commercial customers caused by the impact of weather is mitigated through a deferral account (see Regulation Section).

2. Economically strong service territory.
FEI, post-amalgamation, operates in the Greater Vancouver, Fraser Valley, Thompson, Okanagan, Kootenay, North Central Interior, Vancouver Island, Sunshine Coast and Whistler regions.

3. Good financial profile.
FEI has maintained its capital structure in line with the approved regulatory capital structure. All of the Company's credit metrics as of September 30, 2014, were indicative of the "A" rating category. These metrics are expected to remain stable following the Amalgamation, as the Company is expected to continue to finance its future capex and maintain its balance-sheet leverage in line with the regulatory approved capital structure.

4. Larger customer base.
Following the amalgamation completed on December 31, 2014, FEI has a larger customer base of approximately 960,000 customers compared with the FEI pre-amalgamation customer base of 852,000 customers (as at September 30, 2014). The customer mix is weighted toward residential and commercial customers, whose consumption is less sensitive to economic conditions.

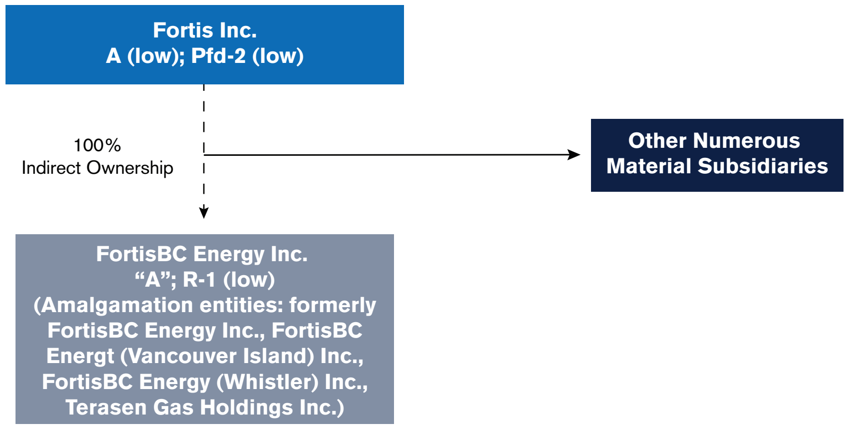
Challenges

1. Tilbury Expansion Project execution risk.
The Company started construction on the expansion of its Tilbury LNG facility (the Tilbury Project) in October 2014. The capital cost of the Tilbury Project is estimated to be approximately $400 million, which is the upper limit set by the Province of British Columbia (the Province) through an Order in Council. Any significant cost overruns above the upper limit may not be recovered through customer rates. The Tilbury Project is expected to be in service in the second half of 2016.

2. Indirect access to the public equity market.
FEI has no direct access to the public equity market. As a result, it finances cash flow deficits by managing its dividend payouts and equity issuances to the parent as well as through debt issuances. The Company's current rating incorporates DBRS's expectation that the parent will continue to provide equity financing support in a timely manner if required.

3. Competition from electricity.
FEI faces more intense competition from electricity in British Columbia than other provinces in Canada (except Québec) because of the low power costs in the Province. DBRS notes that the electricity retail rates in the Province are expected to increase considerably over the next few years, thereby potentially reducing the competition.

Simplified Organization Chart as of January 1, 2015



Amalgamation Update

On December 31, 2014, the amalgamation of FEI, FEVI, FEW and Terasen Gas Holdings Inc. was completed. As part of the approval of the Amalgamation, the BCUC approved the adoption of common rates to be phased in over a three-year period for natural gas delivery to all customers of the new amalgamated entity (known as FEI) except those in the Fort Nelson service area. The ROE and the deemed equity component of the capital structure for the new amalgamated entity is 8.75% and 38.5%, respectively.

The Tilbury LNG Facility Expansion Project

In November 2013, an Order in Council (Special Direction) was signed by the Province to allow FEI to expand its LNG facilities at Tilbury Island, British Columbia. The Special Direction set out a number of requirements for the BCUC as follows:

1. The Tilbury Project is exempt from a Certificate of Public Convenience and Necessity (CPCN) process;
2. The upper limit for the costs related to the expansion project is $400 million; and
3. FEI is allowed to recover the cost of the Tilbury Project from customers.

In October 2014, FEI started construction of the Tilbury Project. The Company will add a second LNG tank and a new liquefier, both expected to be in service in the second half of 2016.

Earnings and Outlook (DOES NOT RECOGNIZE THE RETROACTIVE EFFECT OF THE AMALGAMATION)

Consolidated Income Statement	9 months	9 months	12 months	For the year ended December 31st		
(CA$ millions)	Sep. 30. 14	Sep. 30. 13	Sep. 30. 14	2013	2012	2011
EBITDA 1	280	264	398	382	369	333
EBIT 1	161	154	241	234	241	241
Gross interest expense 1	89	89	118	118	119	118
Pre-tax income	74	66	126	118	123	126
Income tax	15	9	20	14	11	16
Net income before extra. items	59	57	106	104	112	110
Reported net income	59	57	106	104	112	110
Rate base	N/A	N/A	2,765	2,777	2,725	2,636
Approved common equity	38.5%	38.5%	38.5%	38.5%	40.0%	40.0%
Allowed ROE	8.75%	8.75%	8.75%	8.75%	9.50%	9.50%

1 Less inter-company interest payments.

2014 Summary

- In general, earnings in 2014 largely reflected (1) ROE (8.75% in 2014), (2) the deemed equity component of capital structure (38.5% in 2014) and (3) the size of the average rate base for the year (approximately $2,765 million for 2014).
- During the PBR period (2014–2019), earnings will also reflect a 50/50 sharing of variances from the formula-driven operation and maintenance costs, and base capex.

2015 Outlook

- Earnings for 2015 are expected to increase after the Amalgamation as a result of the consolidation of FEI's rate base with FEVI and FEW, while the ROE and deemed equity component of the amalgamated entity will remain the same as FEI's in 2014.

Financial Profile (DOES NOT RECOGNIZE THE RETROACTIVE EFFECT OF THE AMALGAMATION)

Consolidated Cash Flow Statement	9 months	9 months	12 months	For the year ended December 31st		
(CA$ millions)	**Sep. 30. 14**	**Sep. 30. 13**	**Sep. 30. 14**	**2013**	**2012**	**2011**
Net income before extra. items	59	57	106	104	112	110
Depreciation & amortization	119	110	157	148	128	92
Deferred income taxes/Other	(1)	(1)	(1)	(1)	(3)	(9)
Cash flow from operations	177	166	262	251	237	193
Dividends paid	(57)	(84)	(104)	(131)	(85)	(85)
Capex	(159)	(124)	(194)	(159)	(159)	(169)
Free cash flow before WC	(39)	(42)	(36)	(39)	(7)	(61)
Changes in working capital (WC)	23	49	(18)	8	14	84
Changes in regulatory assets & liabilities	(61)	(56)	(34)	(29)	(17)	(10)
Net free cash flow	(77)	(49)	(88)	(60)	(10)	13
Acquisitions	0	0	0	0	0	0
Assets sales/Divestitures	0	0	0	0	0	0
Net changes in equity	0	0	0	0	65	0
Net changes in debt	78	13	115	50	(36)	(15)
Other/Adjustments by DBRS	3	17	(26)	(12)	(14)	4
Change in cash	4	(19)	1	(22)	5	2
Total debt	1,829	1,713	1,829	1,751	1,701	1,737
Total debt in capital structure	49.5%	47.9%	49.5%	48.4%	47.4%	49.1%
Total debt in capital structure 1	61.4%	59.7%	61.4%	60.3%	58.9%	62.6%
Cash flow/Total debt	12.9%	12.9%	14.3%	14.3%	13.9%	11.1%
EBIT gross interest coverage 1	1.82	1.74	2.05	1.99	2.03	2.08
Total debt/EBITDA	6.53	6.49	4.60	4.58	4.61	5.22
Dividend payout ratio	96.6%	147.4%	98.1%	126.0%	75.9%	77.3%

1 Adjusted for operating leases.

2014 Summary

- FEI's financial profile remained relatively stable in 2014 compared with 2013, with a slightly higher debt leverage and a modestly stronger interest coverage ratio.
- All credit metrics for the 12 months ended September 30, 2014, remained within DBRS's "A" rating category.
- Cash deficit was considerably higher than 2013 as a result of higher capex for the year. The increase in capex was largely due to the Tilbury Project.
- The Company financed its 2014 capex program primarily by issuing short-term notes.

2015 Outlook

- Capex in 2015 is expected to be higher than 2014 due to the Tilbury Project and the impact of the Amalgamation.
- DBRS expects FEI's cash flow metrics to be under pressure until the Tilbury Project is in service (expected in the second half of 2016), as free cash flow deficits are expected to persist. However, DBRS expects FEI to maintain its capital structure within the range set by the regulator.

Long-Term Debt and Liquidity (PRIOR TO RECOGNIZING THE IMPACT OF THE AMALGAMATION)

Liquidity

Credit Facilities (As at September 30, 2014)

(CA$ millions)	Committed	Short-Term Notes	Letters of Credit	Available	Expiry
Syndicated unsecured credit facility	500	170	50	280	Aug-2016
Total	**500**	**170**	**50**	**280**	

- The unsecured credit facility is primarily used to support FEI's $500 million commercial paper program. In July 2014, the credit facility maturity was extended to August 2016 with substantially similar terms.
- Due to the seasonal nature of the business, liquidity requirements peak in the fall and winter.
- As at September 30, 2014, FEI had $280 million available under its credit facility. FEI's liquidity should be sufficient to finance the Company's short-term operating needs.

Long-Term Debt, Capital Lease & Finance Obligations Schedule

As of September 30, 2014 (CA$ millions)	Due within 1 Year	Due in Year 2	Due in Year 3	Due in Year 4	Due in Year 5	Thereafter	Total
Amount due	82	206	6	7	33	1,325	1,659
% of total	5%	12%	0%	0%	2%	80%	100%

- The Company's near-term refinancing risk remains modest with $206 million of debt due in 2016.
- DBRS believes that refinancing of the debt maturity is manageable, given the Company's strong credit profile.

Debt Instruments

(CA$ millions)	Sep. 30, 2014	2013
Secured Purchase Money Mortgages (PMMs)	275	275
Unsecured Debentures and MTNs	1,270	1,270
Capital lease and finance obligations	114	119
Total	**1,659**	**1,664**
Credit facilities	170	87
Less: Current portion	(252)	(94)
Total	**1,577**	**1,657**

- MTNs and Unsecured Debentures have the same rating as PMMs based on the following: (1) The outstanding amount of the PMMs is viewed as not significant; and (2) DBRS does not expect FEI to issue new PMMs in the future.
- The PMMs consist of $75 million of Series A notes and $200 million of Series B notes. Series A will mature in September 2015, and Series B will mature in September 2016.

Regulation

Regulation Update

FEI currently operates under a Performance Based Ratemaking (PBR) plan through 2019. FEI had previously operated under a traditional cost-of-service (COS) methodology, which ended December 31, 2013.

- The approved PBR plan incorporates an incentive mechanism for improving operating efficiencies. During the PBR period, operation and maintenance costs and base capex are subject to a formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity improvement factor of 1.1% each year. It also includes a 50/50 sharing of variances from the formula-driven expenditures over the PBR period, and a number of service quality measures.
- In September 2014, the BCUC issued the PBR Decision on FEI's PBR Application. The term of the PBR was extended to 2019. In October 2014, FEI filed a PBR Decision Compliance filing. The 2014 average rate base was updated to approximately $2,765 million, and the 2014 delivery rate increased to 1.8% as compared with the interim delivery rate increase of 1.4%. FEI implemented permanent 2014 delivery rates in November 2014 to reflect the additional delivery rate increase compared with the interim rates and will recover the January 2014 to October 2014 revenue deficiency through a deferral mechanism.

Deferral Accounts

FEI has a number of deferral accounts that are used to ameliorate unanticipated changes in certain forecast items, including the following two mechanisms:

1. Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA):

- Any differences between actual and forecast gas costs are captured and recorded in these deferral accounts to be recovered or refunded in future rates. Forecast gas prices are adjusted on a quarterly basis for commodity rates, mitigating the impact of recovery lag.

2. Revenue Stabilization Adjustment Mechanism (RSAM):

- The RSAM seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in forecast versus actual customer usage throughout the year to recover them in rates over the following two years. This reduces FEI's earnings volatility.
- Volume variances from large-volume industrial, transportation and other customers are not included in this deferral account. However, they are also recovered through a deferral mechanism starting in 2014 as part of the PBR Decision.
- The RSAM and MCRA accounts are currently recovered/refunded in rates over two years. The CCRA is anticipated to be fully recovered within the next fiscal year.

Generic Cost of Capital Proceeding (GCOC Proceeding)

- In May 2013, the BCUC issued a decision on the first stage of the GCOC Proceeding, which determined that FEI's ROE and deemed equity would be set at 8.75% and 38.5%, respectively, both in effect until December 31, 2015.
- Effective January 2014, the BCUC introduced an Automatic Adjustment Mechanism (AAM) to set the ROE on an annual basis. The AAM will be in effect if the actual long-term Government of Canada (GOC) bond yield exceeds 3.8%. The AAM will be in effect until December 31, 2015. The AAM did not take effect in 2014, since the GOC bond yield in October 2013 did not exceed the 3.8% threshold. As a result, the ROE for FEI in 2014 remained at 8.75%.

Regulatory Ring-Fencing

- The regulatory ring-fencing imposed on FEI by the BCUC at the time of Fortis Inc.'s 2007 acquisition of FEI (a continuation of the ring-fencing imposed upon acquisition of the former Terasen Inc. by Kinder Morgan Inc. in 2005) is intended to ensure that public interest is protected and that FEI will continue to operate as a separate, stand-alone entity without undue parental influence. One of these conditions is that FEI must maintain its debt-to-capital ratio in line with the regulatory capital structure.

FortisBC Energy Inc.

Balance Sheet (Does not recognize the retroactive effect of the Amalgamation)

(CA$ millions)	Sep. 30	Dec. 31	Dec. 31		Sep. 30	Dec. 31	Dec. 31
Assets	**2014**	**2013**	**2012**	**Liabilities & Equity**	**2014**	**2013**	**2012**
Cash & equivalents	4	0	22	S.T. borrowings	170	87	33
Accounts receivable	96	228	205	Current portion of debt	82	7	7
Inventories	129	81	95	Accounts payable	284	221	226
Current regulatory assets	15	18	28	Current regulatory liabilities	14	39	35
Others	20	13	16	Others	0	40	32
Total Current Assets	**264**	**340**	**366**	**Total Current Liabilities**	**550**	**394**	**333**
Net fixed assets	2,766	2,651	2,604	Long-term debt	1,577	1,657	1,661
Intangible assets	121	122	121	Deferred income taxes	334	327	309
Goodwill	769	769	769	Regulatory liabilities	41	55	55
Regulatory assets	596	560	561	Other L.T. liabilities	170	167	194
Others	22	22	22	Shareholders equity	1,866	1,864	1,891
Total Assets	**4,538**	**4,464**	**4,443**	**Total Liab. & SE**	**4,538**	**4,464**	**4,443**

FortisBC Energy Inc.

Balance Sheet & Liquidity & Capital Ratios	9 months	9 months	12 months	For the year ended December 31st		
(Does not recognize the retroactive effect of the Amalgamation)	**Sep. 30. 14**	**Sep. 30. 13**	**Sep. 30. 14**	**2013**	**2012**	**2011**
Current ratio	0.48	0.80	0.48	0.86	1.10	1.01
Total debt in capital structure	49.5%	47.9%	49.5%	48.4%	47.4%	49.1%
Total debt in capital structure 1	61.4%	59.7%	61.4%	60.3%	58.9%	62.6%
Cash flow/Total debt	12.9%	12.9%	14.3%	14.3%	13.9%	11.1%
Cash flow/Total debt 1	12.8%	12.8%	14.2%	14.2%	13.8%	10.5%
Cash flow/Capex	1.20	1.66	1.27	1.58	1.49	1.14
(Cash flow - Dividends)/Capex	0.82	0.82	0.77	0.75	0.96	0.64
Approved common equity	38.5%	38.5%	38.5%	38.5%	40.0%	40.0%
Dividend payout ratio	96.6%	147.4%	98.1%	126.0%	75.9%	77.3%
Coverage Ratios (times)						
EBIT gross interest coverage	1.81	1.73	2.04	1.98	2.03	2.04
EBITDA gross interest coverage	3.15	2.97	3.37	3.24	3.10	2.82
Fixed-charges coverage	1.81	1.73	2.04	1.98	2.03	2.04
Debt/EBITDA	6.53	6.49	4.60	4.58	4.61	5.22
EBIT gross interest coverage 1	1.82	1.74	2.05	1.99	2.03	2.08
Profitability Ratios						
EBITDA margin	61.0%	60.0%	61.0%	60.3%	60.0%	56.5%
EBIT margin	35.1%	35.0%	37.0%	37.0%	39.2%	40.9%
Profit margin	12.9%	13.0%	16.3%	16.4%	18.2%	18.7%
Return on avg. common equity	7.2%	6.9%	9.7%	9.4%	10.4%	10.7%
Return on capital	5.9%	6.0%	6.9%	6.9%	7.3%	7.1%
Allowed ROE	8.75%	8.75%	8.75%	8.75%	9.5%	9.5%

1 Adjusted for operating leases.

Rating History

Debt Rated	Current	2014	2013	2012	2011	2010	2009
Issuer Rating	A	A	A	A	NR	NR	NR
MTNs & Unsecured Debentures	A	A	A	A	A	A	A
Purchase Money Mortgages	A	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Commercial Paper Limit

- $500 million.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

MOODY'S
INVESTORS SERVICE

Credit Opinion: FortisBC Energy Inc.

Global Credit Research - 20 Jul 2015

Vancouver, British Columbia, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Secured -Dom Curr	A1
Senior Unsecured -Dom Curr	A3

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Key Indicators

[1]**FortisBC Energy Inc.**

	3/31/2015(L)	12/31/2014	12/31/2013	12/31/2012	12/31/2011
CFO pre-WC + Interest / Interest	**2.8x**	**2.8x**	**2.7x**	**2.5x**	**2.3x**
CFO pre-WC / Debt	**15.0%**	**14.4%**	**15.1%**	**14.5%**	**11.2%**
CFO pre-WC - Dividends / Debt	**9.1%**	**10.3%**	**8.0%**	**9.6%**	**6.6%**
Debt / Capitalization	**44.8%**	**45.2%**	**43.6%**	**44.0%**	**47.4%**

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Credit supportive regulatory environment

PBR marginally increases risk

Stable cash flow and weak financial metrics

FEI is independent of ultimate parent, Fortis Inc

Corporate Profile

FortisBC Energy Inc. (FEI), headquartered in Vancouver, is the largest gas local distribution company (LDC) in British Columbia serving about 967,000 customers, around 90% of which are residential. As the result of the amalgamation on December 31, 2014, FEI began to consolidate results of FortisBC Energy (Vancouver Island) Inc. (FEVI; A3 prior to consolidation), FortisBC Energy (Whistler) Inc. (FEW, not rated) and Terasen Gas Holdings Inc. (TGHI; not rated). FEI is regulated by the British Columbia Utilities Commission (BCUC). From 2010 to 2013, FEI's revenue requirement was determined under cost of service regulation. For the 2014-2019 period, FEI is subject to performance based regulation (PBR), which was previously in effect from 2004 to 2009. FEI is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI not rated) which, in turn, is wholly owned by Fortis Inc. (FTS, not rated), a diversified electric and gas utility holding company.

SUMMARY RATING RATIONALE

FEI's credit quality is driven by its credit supportive regulatory environment and its monopoly position. The company has a long term track record of earning its allowed return on equity and its cash flow continues to be highly predictable. This is offset by the company's weak financial metrics, with limited headroom at the current rating level, that are primarily a product of the allowed return on equity and the equity component of its capital structure.

DETAILED RATING CONSIDERATIONS

CREDIT SUPPORTIVE REGUALTORY ENVIRONMENT

FEI's investment grade rating has been primarily driven by its credit supportive regulatory environment and its monopoly position. Rates have typically set using a cost of service framework and a forward test year that has enabled the company to recover its costs and earn an allowed return established bythe regulator, resulting in stable cash flow. The company has a track record of passing through its commodity costs in rates and has no direct exposure to commodity price risk and limited volume risk. To the extent that these and many other costs differ from forecast values, deferral or true up mechanisms limit exposure to forecast error. As a result the company has a long track record of earning the return on equity (ROE) established by the regulator.

For capital projects in excess of $5 million the company requires a certificate of public convenience and necessity (CPCN) that reduces the probability of cost disallowances, a credit positive. For large capital projects, the company receives a weighted average cost of capital in rates for financing costs incurred during construction; however, depreciation charges only begin once projects are complete and added to rate base. We do not believe the company has experienced any material cost disallowances. Decisions from the regulator tend to be reasonably predictable, consistent and transparent with a consultative approach. We have noted regulatory lag in some recent decisions, but the company has generally received interim rates as requested, mitigating some lag effects. Generally, when utility or other stakeholders materially disagree with some aspects of decisions, they have been successful in asking the regulator to review and vary its decisions with final outcomes acceptable to all parties as evidenced by a lack of court challenges. The company has access to the courts to challenge regulatory decisions, although we do not believe this has happened since the utility was acquired by Fortis Inc. The legislative and judicial underpinnings of the regulatory framework continue to be stable. We view debt-financed deferral accounts as a credit negative, however the balances remain small.

The company benefits from a monopoly position. We believe that its customers, who are primarily residential, continue to have the capacity and willingness to pay their bills.

PBR MARGINALLY INCREASES RISK

The shift to PBR marginally increases risk because of the potential for increased cash flow volatility compared to cost of service regulation. However, we believe that management will be successful in achieving the challenges inherent in its PBR plan and continue to earn the allowed return on equity established by the regulator. While there is some increased regulatory risk pending resolution of some outstanding issues, particularly capital spending, once a precedent is established it will reduce regulatory risk for the PBR term. Performance based regulation utilizes a formula based approach to rate making. Revenues associated with controllable operating expenses and capital expenditure are adjusted on an annual basis during the 6 year period of the plan, from 2014-2019. Each year they are adjusted for inflation, a productivity or X-factor of 1.1% (FBC 1.03%), while initial rates were based on 2013 cost of service based rates with some adjustments. Many costs remain pass through items; for example, interest expenses and taxes limiting risk to the utility. The PBR plan has a symmetrical earnings sharing mechanism that is partially subject to service quality indicators. An annual review process forms part of the PBR plan to mitigate the risk of the plan failing to achieve its objectives. CPCN capital has been excluded from the PBR plan on a temporary basis, while different options are evaluated.

STABLE CASH FLOW AND WEAK FINANCIAL METRICS

We expect the company to continue to generate stable cash flow, a key credit strength. Underpinning this stability, cash flow from operations is generally a function of the company's rate base, its deemed capital structure (38.5%

equity layer effective 1/1/2013 - 12/31/2015), the allowed return on equity (currently 8.75%) and depreciation. The ROE contains an automatic adjustment mechanism for 2014 and 2015 that increases rates in case of rising interest rates; however, because of ongoing low interest rates neither 2014 nor 2015 qualified for an adjustment. Our analysis assumes that the company continues to earn its allowed ROE. We expect the company's dividend policy net of any equity injections will maintain the deemed capital structure. The company is forecast to have limited financial metric headroom at the current rating. Planned large capital projects are expected to place some downward pressure on credit metrics; for example, the Tilbury LNG Expansion Project (Tilbury 1A) with a capital cost of about C$440 million because depreciation cash flow will not begin until this project is in operation. In addition, the amalgamation will place some modest downward pressure on financial metrics as the company unwinds a regulated liability in 2015 and 2016. As a result, we forecast that credit metrics will decline somewhat in 2015 and improve as capital projects are completed in 2016-17. This forecasted weakness is incorporated in the current rating.

FEI IS INDEPENDENT OF ULTIMATE PARENT FORTIS INC

We consider FEI to be operationally and financially independent of ultimate parent Fortis Inc, although the company may periodically rely on its parent for equity injections to maintain its capital structure in line with the regulator's established parameters. We expect that Fortis Inc. would provide extraordinary support to FEI, if required, provided that the parent had the economic incentive to do so. We believe that the parent will continue to have sufficient resources to provide support, if required. At FYE 2014, FTS had a $1 billion committed revolving credit facility at the FTS corporate level, of which $509 million was unused. Ring fencing provisions at FEI limit the ability of Fortis Inc to upstream cash, although we do not believe the parent would seek to increase leverage above levels established by the regulator.

Liquidity Profile

FEI has adequate liquidity. For LTM 1Q15, FEI had negative free cash flow of $203 million as a result of $321 million CFO, $136 million dividends and $388 million capex. We estimate annual negative free cash flow at $300-350 million in 2015 on the basis of about $450 million capex and increased annual dividends from the 2014 level. We expect FEI to manage dividend payouts and parent equity injections to maintain the equity layer close to the approved level of 38.5% along with its capex spending and borrowing profile.

FEI has $700 million in two syndicated credit facilities that support a commercial paper program. The $500 million and $200 million credit facilities mature in August 2016 and December 2015, respectively. Our liquidity analysis incorporates the expectation that the company will extend the maturities of these facilities well in advance of their expiration. The company is currently well below the debt to total capitalization ratio covenant (maximum 75%) in the credit agreements. At March 31, 2015, $352 million was available under these facilities.

FEI has limited short-term debt obligations in the next 12 months: $75 million of debt maturity in September 2015, $10 million government loan and $6 million capital lease obligation. The next material maturity is in September 2016 when $200 million of debt matures.

Rating Outlook

The stable outlook is based on our expectation of a continuing supportive regulatory environment and stable, albeit weak financial metrics with ongoing limited headroom at the current rating level.

What Could Change the Rating - Up

Given the ongoing forecasted weakness in credit metrics an upgrade is unlikely. We could upgrade the company with a material sustained improvement in financial metrics, including CFO pre W/C to debt in the mid to high teens.

What Could Change the Rating - Down

While we don't expect it several factors could lead to a downgrade. For example, an unexpected, material adverse regulatory decision or a forecast of a sustained deterioration in credit metrics including CFO/pre-W/C to debt of less than 11%.

Rating Factors

FortisBC Energy Inc.

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2015		[3]Moody's 12-18 Month Forward ViewAs of 7/16/2015	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	2.7x	Ba	2.4x - 2.8x	Ba
b) CFO pre-WC / Debt (3 Year Avg)	16.7%	Baa	11% - 13%	Baa
c) CFO pre-WC - Dividends / Debt (3 Year Avg)	10.3%	Baa	5% - 8%	Ba
d) Debt / Capitalization (3 Year Avg)	43.4%	A	46% - 49%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. [2] As of 3/31/2015(L); Source: Moody's Financial Metrics [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.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on http://www.moodys.com for the most updated credit rating action information and rating history.

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Appendix B Evidence of Mr. James Coyne, Concentric Energy Advisors Inc., regarding the cost of capital estimation

Appendix C Evidence of FEI regarding business risk for FEI

1. INTRODUCTION AND OVERVIEW

1.1 INTRODUCTION

On May 10, 2013, the British Columbia Utilities Commission (the "Commission") issued Order No. G-75-13 for Stage 1 of the Generic Cost of Capital (GCOC) proceeding, establishing FortisBC Energy Inc. (FEI or the Company) as the benchmark utility with a return on equity (ROE) of 8.75 percent and common equity ratio of 38.5 percent. The Commission Order directed FEI to file an application for the review of the common equity component and the ROE by no later than November 30, 2015.

In accordance with the Commission's Order and pursuant to sections 59 to 61 of the *Utilities Commission Act,* R.S.B.C. 1996, c.473 (*Act*), FEI applies for approval of a capital structure consisting of 40 percent equity and 60 percent debt, and a return on common equity of <@> percent. FEI respectfully submits that the accompanying evidence on FEI's business risk, financial market conditions, and return on equity and capital structure considerations demonstrates that FEI's proposals meet the Fair Return Standard, and should be approved.

1.2 EXECUTIVE SUMMARY

Fair Return Standard

The Fair Return Standard is a fundamental element of the regulatory compact and is captured in section 59(5) of the *Act*. The Commission has confirmed[1] that the Fair Return Standard requires that a fair or reasonable overall return (including a return on and of capital) is one that meets all three of the following requirements:

- is comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
- enables the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and

[1] 2009 Decision, at page 15, citing p.8 of RH-1-2008 in respect of TQM.

- permits incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement).

The application of the Fair Return Standard to FEI must account for the ongoing challenges that FEI faces in attracting capital on reasonable terms and conditions. It must reflect the business risks facing FEI that define the risk that the Company faces in achieving a fair return on and of invested capital in both the short and long-term. In addition, it must account for the risks associated with continued volatility and uncertainty in the financial markets and economic environment. It is the combination of all of these factors that justifies a capital structure consisting of 40 percent equity and 60 percent debt, and a return on common equity of <@> percent.

Business Risk Since 2012

Business risk analysis is an important factor in investors' decision-making process. A key reference point for assessing FEI's business risk is the GCOC Stage 1 proceeding. Since the Commission considered FEI's cost of capital relatively recently, there is a significant amount of continuity in the underlying business conditions applicable to FEI. However, there have been developments that are important for understanding why FEI considers that FEI's required return on equity and equity component of capital structure is higher than what the Commission approved in the GCOC Stage 1 Decision.

Amalgamation

One notable change since the GCOC Stage 1 proceeding is the amalgamation of FEI with FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW). The Commission approved the amalgamation of FEI, FEVI and FEW on February 26, 2014, by Order G-21-14. On May 23, 2014, the Lieutenant Governor in Council (LGIC) issued Order in Council No. 300 consenting to the amalgamation. The amalgamated entity is carrying on business as FEI, and in this proceeding may be referred to as "FEI", "the amalgamated FEI" or "FEI Amalco" as the context requires.

At the time of the amalgamation, both FEW and FEVI had a higher ROE and thicker equity than FEI, commensurate with their relatively higher business risk. On March 25, 2014, the Commission issued its Decision on the Stage 2 GCOC proceeding (Order No. G-47-14). The GCOC Stage 2 Decision set a common equity ratio of 41.5 percent for both FEVI and FEW and equity premiums over the benchmark utility's ROE of 50 and 75 basis points for FEVI and FEW, respectively.

In the GCOC Stage 2 Decision, the Commission acknowledged that the evidence in the GCOC proceedings treated FEI, FEVI and FEW as separate entities and that it did not contemplate the potential impact of an amalgamated entity.[2] The Commission decided that once the amalgamation has been effected, the ROE and capital structure should remain "*the same for the amalgamated entity as for FEI as the benchmark utility*"; however, the Commission also indicated that, if FEI considers the cost of capital for the amalgamated entity is not indicative of current circumstances, then it may apply to the Commission on behalf of the amalgamated FEI.[3]

In this filing, FEI has considered the extent to which FEI's risk profile has changed as a result of amalgamating with FEVI and FEW. While amalgamation is a factor affecting FEI's business risk that should be considered, it is not the primary justification for FEI's request to increase FEI's equity thickness or ROE. FEI Amalco remains a large natural gas distribution utility, regulated by the BCUC, whose core business is to serve space and water heating load to its customers. As before, the core market is experiencing declining use per customer and low customer growth while facing the same competitive challenges as FEI did, pre-amalgamation. The addition of Vancouver Island and Whistler service territories to FEI's service area has increased amalgamated FEI's supply interruption risk as both areas are exposed to greater security of supply risk. As such, FEI Amalco is now exposed to certain factors as a result of amalgamation that contribute to a slight increase in overall business risk.

<u>Changes in FEI's Business Risk Apart from Amalgamation</u>

Amalgamated FEI's business risk, independent of the effect of amalgamation noted above, is also broadly similar to what it was in 2012; however, there are some differences that point to a somewhat higher business risk than what is reflected in the capital structure and ROE determined in the GCOC Stage 1 Decision.

[2] GCOC Stage 2 Decision, P.138
[3] ditto

FEI business risk is closely related to its ability to attract new customers (add new load to the system) and retain its existing customer base in its various customer segments (maintain or increase the throughput levels of its existing customers). Key indicators such as total throughput, use per customer or natural gas capture rates in various sectors can be used, in conjunction with other considerations, to assess the change in a utility's risk status. For instance, all else equal, if throughput levels decline for whatever reason, FEI's business risk in effect increases because the invested capital must be recovered over fewer GJs. These indicators are affected by various exogenous factors, including customer preference, price competitiveness of natural gas versus other alternatives, macro-economic environment as well as provincial and local governments' energy policies and regulations. Closely related to business risk is the risk faced by utilities, termed regulatory risk, associated with having to obtain approval from a regulator for rates (and therefore revenues), the cost of capital, as well as new utility investments.

FEI has performed its business risk analysis using the same risk categorization that it had used in the GCOC Stage 1 proceeding, so as to facilitate the Commission's review of how business risk has evolved over time. FEI's assessment of risk can be summarized as follows:

- For the majority of the risk categories identified, the risk status has remained relatively stable compared to 2012.

- The primary difference is in the political risk category. Most notably, FEI faces greater risk now due to recent local government policies and intensified initiatives to promote mandatory connection to neighbourhood energy systems or installing renewable or higher efficiency energy systems that will hinder FEI's ability to attract new customers and/or retain existing ones. In addition, the recent legal developments related to Aboriginal and title issues have led to a slight increase in Aboriginal and title issues risks.

- The adoption of PBR in 2014 has given rise to some additional regulatory uncertainty and risk compared to previous periods, although the broader regulatory constructs that supported FEI's characterization of regulatory risk in 2012 remain substantially the same.

Therefore the amalgamated FEI's overall business risk is best characterized as being similar to that of the 2012, and is trending higher.

Evidence on Cost of Capital, Financial Market Conditions and Credit Metrics

FEI retained Mr. James Coyne of Concentric Energy Advisors Inc. (CEA or Concentric), a cost of capital expert with many years of experience regarding the North American utility industry, to provide an expert opinion on FEI's cost of capital. Mr. Coyne's report is attached as Appendix B. Mr. Coyne's evidence, among other things:

- Discusses capital market conditions in the U.S. and Canada, concluding that U.S. and Canadian capital markets are highly integrated and that it is appropriate to use the U.S. proxy group data for ROE and capital structure determination.

- Conducts Capital Asset Pricing Model and Discounted Cash Flow analyses, with alternative inputs and model specifications, to determine an appropriate ROE.

- Assesses FEI's operating and financial profile and conducts a comparative risk analysis to support the proposed capital structure.

Mr. Coyne concludes, based on his analysis, that the proposed minimum equity component for the amalgamated FEI at 40% should be combined with a ROE of @% to meet the Fair Return Standard in the current market conditions and in light of FEI's overall business and financial risk.

In addition, FEI has presented information regarding capital structure considerations, including debt issuance capacity and debt rating agency concerns. FEIs analysis demonstrates that an increase in the common equity component of its capital structure to 40% is warranted, considering the upward trend in FEI's business risk, the need to strengthen the Company's weak credit metrics to support the ongoing access to capital investment and potential constraints in issuing new debt under the Company's Trust Indenture Agreement during a period of high capital expenditure requirements.

Automatic Adjustment Mechanism

FEI continues to believe that the appropriate approach to set the allowed ROE and capital structure is through a traditional cost of capital application process. However, if the Commission determines to maintain an Automatic Adjustment Mechanism (AAM), it should continue to use the two factor model approved by the Commission in its GCOC Stage 1 Decision.

Benchmark Utility

As cited earlier in this section, the GCOC Stage 2 Decision stated that the amalgamated FEI shall remain the benchmark utility[4]. FEI believes that Amalgamated FEI continues to be the logical choice to serve as the benchmark utility. FEI Amalco is engaged in the same businesses as pre-amalgamation FEI. The Commission should consider the business and risk profile of the amalgamated FEI and continue to treat FEI as the benchmark utility. This view has been confirmed by FEI's cost of capital expert. However, it should be noted that a determination in this regard does not impact the determination of FEI's cost of capital. The benchmark is used in setting the ROE for other utilities in their own cost of capital applications.

1.3 OUTLINE OF THE FILING

This Filing, including the appended materials, provides the necessary evidentiary basis, upon which the Commission can determine a fair return for the amalgamated FEI.

The Appendices are:

- Appendix A – Company-Specific Information for FEI.
- Appendix B – Evidence of Concentric Energy Advisors Inc., regarding the appropriate cost of capital for amalgamated FEI.
- Appendix C - Evidence of FEI regarding business risk facing amalgamated FEI.

[4] ditto

In the following sections, FEI set out its position and evidence on the following matters:

- The Fair Return Standard and its implications for setting the cost of capital for a benchmark utility;
- The appropriate approach to assessing business risk for amalgamated FEI;
- The appropriate ROE for amalgamated FEI;
- The appropriate capital structure for FEI;
- The Automatic Adjustment Mechanism; and
- FEI as a benchmark for other utilities.

1.4 APPLICATION OF THE FAIR RETURN STANDARD TO THE BENCHMARK

In this section, we provide an overview of the Fair Return Standard, which the Commission has repeatedly confirmed applies in determining a utility's cost of capital for ratemaking purposes. The application of the Fair Return Standard in practice is addressed in detail in Mr. Coyne's expert evidence.

The Obligation to Fix a Fair Return for Ratemaking Purposes is Absolute

The Commission's obligation to determine, in respect of every utility, a cost of capital for ratemaking purposes that meets the Fair Return Standard is expressed in the *UCA*. The obligation is absolute, and is not an exercise in balancing shareholder and ratepayer interests.

Section 59(5) of the *UCA* provides that a rate is "unjust" or "unreasonable" if it is:

> (a) more than a fair and reasonable charge for service of the nature and quality provided by the utility;
>
> (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; or

(c) unjust and unreasonable for any other reason.

There is a substantial body of judicial case law that deals with the principles that utility rate regulators must apply in determining a fair and reasonable return for the utility shareholder. The following passage from the Commission's 2006 Decision articulates the Commission's duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital:

> *The Commission Panel does not accept that the reference by Martland J. [in British Columbia Electric Railway Co. v. British Columbia Public Utilities Commission[5]] to a "balancing of interests" to mean that the exercise of determining a fair return is an exercise of balancing the customers' interests in low rates, assuming no detrimental effects on the quality of service, with the shareholders' interest in a fair return. In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital*.[6]

Similarly, in the GCOC Stage 1 Decision, the Commission reiterated the principles articulated in 2006 and 2009 ROE Decisions and confirmed that it has a duty to provide a reasonable opportunity to the utility to earn a fair return on and of invested capital consistent with the previous decisions[7].

This articulation is consistent with prior court decisions, including the concurring reasons of Locke J. in *British Columbia Electric Railway,* in which Locke J. stated in part: "The Commission is directed by s.16(1)(a) [of the old legislation] to consider all matters which it deems proper as affecting the rate but that consideration is to be given in the light of the fact that the obligation to approve rates which will give a fair and reasonable return is absolute."[8]

The application of the Fair Return Standard ensures that utilities are in a position to: meet their customers' service needs at a reasonable cost; attract investment capital at reasonable cost under all market conditions; earn a fair and reasonable return on

5 [1960] S.C.R. 837
6 2006 ROE Decision, p.8.
7 GCOC Stage 1 Decision, Page 12
8 [1960] S.C.R. 837 at 848

previously invested capital; support the energy and environmental policy objectives of the BC Government; pursue investments in efficiency; and, be sustainable in the face of ongoing and changing business risks. In addition to being fair to the utility, adhering to the Fair Return Standard is beneficial for customers who can continue to obtain utility service from a utility operating on a financially strong and sustainable basis.

Adhering to the Fair Return Standard Involves Satisfying Three Tests

The Commission has endorsed[9] the National Energy Board's ("NEB") articulation of the Fair Return Standard in NEB Decision RH-1-2008. The NEB had stated:

> "The Fair Return Standard requires that a fair or reasonable overall return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement)."

Each of the three requirements of the Fair Return Standard is separate and distinct and all three must be satisfied. None of the three requirements is given priority over the others. In other words, the Fair Return Standard is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained and the return allowed is comparable to the returns of enterprises of similar risk.

1.5 FEI BUSINESS RISKS

FEI's business risk informs its cost of capital because it impacts the likelihood that the Company will be able to earn a fair return on and of its invested capital. The section below provides a high level summary of factors affecting FEI's risk profile. FEI's complete evidence regarding its business risks is found in Appendix C. In addition, Mr. Coyne has reviewed FEI's business risk evidence and has conducted a comparative risk

[9] 2009 Decision, at page 15, citing p.8 of RH-1-2008 in respect of TQM.

analysis of FEI's business and financial risks relative to Canadian and U.S. proxy groups. Mr. Coyne's analysis is included in his report (Appendix B).

In the GCOC Stage 1 Decision, the Commission defined risk "*as the probability that the future cash flows will not be realized or will be variable resulting in a failure to meet investors' expectation*" and asserted that the investment risk comprises of the sum of business risk, financial risk and regulatory risk[10]. The Commission also reaffirmed its previous statement in 2009 Decision that "*the assessment of the risks has a significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes*."

A business risk assessment is by its very nature a qualitative assessment. In general, however, there is a positive relationship between business risk and cost of capital, i.e., the higher the business risk, the higher return required by investors and therefore higher cost of capital.

Business risk can be categorized in different forms. However for the sake of consistency and continuity of risk assessment, FEI adopts the same eight business risk categories that were identified in the GCOC proceedings. These eight categories conform to the Commission's definition of risk as each one of these risk categories and their sub-sections can potentially limit FEI's ability to realize its future cash flows and/or meet investors' expectations[11]. The risk categories are:

<u>Regulatory risk</u>: Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty. It gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that does not provide FEI with an opportunity to earn its fair return, or that necessary investments are not approved. The broader regulatory constructs that supported FEI's characterization of regulatory risk in 2012 remain in place, although the 2014 PBR Decision resulted in some additional regulatory uncertainty. FEI has thus assessed its overall regulatory risk

[10] GCOC Stage 1 Decision, P.24. Note that the pertinent risk as far as a return on capital is concerned is not the risk of *losing money*, but that investors will not earn a fair return on investment, which they are entitled to expect when investing.

[11] The difference is that some these risk categories can impact investor's expectation in a short period of time while others are more long-term risk factors.

as being similar to what it was in 2012, with the potential to be higher over the term of PBR.

Market shift risk: This risk category considers the various market elements that influence FEI's ability to attract new customers and retain its existing customer base and throughput. Similar to 2012, the trend in FEI's throughput level, particularly for the residential sector is characterized by: (a) weak capture rates in new construction market in the growing multi-family dwelling sector, and (b) declining use per customer from existing and new customers which are caused by factors such as smaller average dwelling size, higher capital costs for natural gas appliances versus electric appliances, changes in customers' preference and improvements in energy efficiency and conservation efforts supported by provincial and local governments' policies.

Political risk: This risk category addresses the impact of provincial and local government policies, as well as aboriginal rights and title issues, on FEI's operations and its ability to attract new customers and/or retain existing ones. Government policies in particular have a direct influence on FEI's growth potential. As in 2012, the provincial government continues to discourage the use of natural gas in FEI's core space heating and water heating markets while promoting the role of natural gas in the transportation sector and LNG export. The intensity of local government green initiatives, and their potential to significantly impact FEI's operations has increased since 2012. For instance, FEI's capture rate is threatened by the recent updates to certain municipality bylaws proposing the mandatory connection of new buildings and developments of entire neighborhoods to district energy systems. In addition, FEI may fail to retain some of its existing customers due to the amendments to certain bylaws that require higher efficiency appliances that are not easily installed in older homes. On the subject of Aboriginal rights and title issues, the 2014 Supreme Court of Canada Decision in *Tsilhqot'in Nation v. British Columbia* introduced new uncertainties. As such, political risk is assessed as higher.

Energy price risk: This risk category consists of natural gas commodity price risk, natural gas commodity price volatility risk and price competitiveness of natural gas (including the upfront and installation costs). These risk factors incorporate elements of both long-term and short-term risk. While actual spot market prices are currently similar to where they were at this time in 2012, medium and long term commodity price forecasts are lower than what was expected in 2012. However, market prices continue to remain volatile, despite the abundance of gas supply driven by shale gas production growth. In terms of competitiveness, the current price competitiveness of natural gas versus electricity has improved on an operating cost basis as electricity rates have increased relative to FEI natural gas rates. However, the upfront and installation costs have not changed significantly for natural gas versus electricity and this, along with other non-price factors, continues to add to the challenge of maintaining FEI system throughput. All things considered, FEI assesses that the overall risk associated with energy price is similar to that of 2012 levels.

Business profile: FEI's business profile is characterized by a large service territory and a relatively large customer base. The business profile of the FEI as a result of the amalgamation is not materially different from FEI's pre-amalgamated business profile.

Economic conditions: Economic conditions shape companies' and households' consumption and investment decisions which in turn could impact FEI's throughput and growth potential. The current Canadian economic environment continues to be dominated by uncertainty. A combination of factors from the significant drop in oil prices and a slow-down in economic growth in Europe and China, to a weaker Canadian dollar and U.S. recovery leads to the assessment that while the overall Canadian economy has fell technically into recession in the first half of the 2015, the impact of the overall economic condition on BC economy is not materially different from 2012 levels.

Operating risk: This risk category includes the assessment of FEI's system integrity and the possibility of third party damages and the unexpected events. All things considered, the overall operating risk is assessed to be similar to 2012.

Energy supply risk: Compared to 2012, the natural gas transportation infrastructure in FEI's service territory has remained relatively unchanged. As discussed in the GCOC proceeding the development of several significant gas transmission infrastructure projects connecting BC deposits with Alberta and eastern markets in the coming years could alter the amount of gas available to FEI and the historical pricing relationship of BC supply in relation to Alberta production. This could have a negative impact on the price that consumers pay for natural gas in BC in the coming years. The addition of FEVI and FEW to amalgamated FEI's service territory has slightly increased FEI's exposure to security of supply risk, as those two utilities were downstream of FEI on a radial system that crosses challenging terrain and the Strait of Georgia. As such, the overall risk is considered to be slightly higher than 2012 levels.

Considered together, amalgamated FEI's overall business risk is best characterized as being similar to that of the 2012 benchmark utility (non-amalgamated FEI) and trending higher.

1.6 Proposed ROE for FEI

FEI submits that the appropriate allowed ROE is @%, based on a minimum of 40% common equity. These proposals are supported by the expert evidence of Mr. Coyne. Mr. Coyne's methodology for estimating the appropriate ROE is consistent with the key elements of how the Commission approached ROE in the previous proceedings.

In the previous proceedings, the Commission has supported the application of discounted cash flow (DCF) and Capital Asset Pricing Model (CAPM) as the main methodologies to calculate a utility's cost of equity. The Commission has also consistently supported the use of U.S. proxy group of comparable companies' data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results.

For instance, in the 2009 cost of capital Decision, the Commission accorded the primary weight to the DCF approach stating that DCF model has "*more appeal in that it is based on a sound theoretical base, it is forward looking and can be utility specific*"[12]. The Commission also concluded that "*given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics*"[13].

In the 2012 GCOC stage-1 Decision, the Commission reiterated its support for the DCF and CAPM models however gave equal weights to the two methodologies:

[12] 2009 Cost of Capital Decision, P.45
[13] 2009 Cost of Capital Decision, P.16

> *The Panel finds that the two most compelling frameworks for assessing the cost of equity are the DCF model and the CAPM. These models have well understood theoretical bases and explicitly recognize the opportunity cost of capital. Accordingly, these two models are given equal weight in determining the allowed ROE.*

Similar to the Commission's approach in past decisions, Mr. Coyne's view is that more than one test should be used to determine the fair ROE. He uses both DCF and CAPM methodologies, with alternative inputs and model specifications, to calculate a range for ROE estimation. Consistent with the Commission's past approach, Mr. Coyne only used authorized returns in other jurisdictions as a check on his ROE range, not as part of a formal comparable earnings test *per se*.

The results produced by his various methods and inputs cover a broad spectrum from @ percent to @ percent for U.S. gas distribution utility proxy group to @ percent to @ percent for Canadian utility proxy groups (all results include the standard 50 bps flotation costs approved by the Commission previously). Relying on the estimated ROE ranges and the comparison of FEI's business and financial risk with other utilities in proxy groups Concentric concludes that a reasonable ROE for FEI is between @ percent and @ percent. Mr. Coyne's complete evidence can be found in Appendix B.

1.7 CAPITAL STRUCTURE FOR FEI SHOULD INCLUDE 40% EQUITY

Utilities are large consumers of both equity and debt capital. Their fundamentals are watched carefully and scrutinized thoroughly by the financial analyst community for equity investors and by the credit rating agencies for debt holders. The latter are especially sensitive to the proportion of common equity in a utility's capital structure as it provides security for investors lending money to a utility, and to the cash generated by the allowed returns to ensure that the interest on the debt of the utility can be serviced.

FEI's financial flexibility and financial integrity depend on its ability to access the capital markets on reasonable terms and pricing in all economic conditions. A stand-alone investment grade debt rating in the A category ensures FEI's ability to access capital markets and gives FEI the required flexibility to finance its large capital plan on reasonable terms.

FEI's increasing business risks, its relatively weak financial metrics and potential constraints in debt issuance capacity demonstrate that the common equity ratio should be increased to 40%. FEI's continued weak credit metrics impact the credit rating agencies' assessments of the Company's ratings, which impact the financing terms and flexibility when accessing debt capital markets. This is particularly important currently, considering the Company's high capital expenditure requirements and the ongoing access to debt capital that will be necessary. The requested increase in the common equity ratio is further supported by a comparison of FEI's credit metrics to its Canadian utility peers and the continued upward trend in FEI business risk. Additionally, the increase in the common equity component of the capital structure will reduce pressure on the Company's debt issuance capacity under the Trust Indenture, which may become constrained due to the expiration of Purchase Money Mortgages (PMMs) and increasing debt issuance requirements.

As such, FEI respectfully submits that the equity component of FEI's capital structure should be increased from the current 38.5% to 40% to adequately reflect FEI's business risk, and appropriately address the requirements that meet the Fair Return Standard from a capital structure perspective, ensuring that financial integrity and flexibility is maintained as well as allow FEI to attract capital on a comparable basis with its North American peers.

Mr. Coyne conducted a comparative risk analysis of FEI's risk with the Canadian and U.S. proxy groups and reviewed FEI's credit metrics. In his expert opinion, a 40% equity thickness is appropriate, but at the low end of the range of reasonableness because of FEI's higher risks relative to the proxy companies especially with regards to long-term business risk and financial risk. For more information regarding Mr. Coyne's evidence on this matter please refer to Appendix B.

<u>Business Risk Assessment Supports Requested Capital Structure</u>

In the GCOC Stage-1 Decision, the Commission panel recognized that business risk, particularly long-term business risk, should be reflected in the capital structure of the utility, considering the investors' ability to recover their invested capital. The Commission further explained the link between business risk and capital structure as follows:

> *"This is because if the underlying risk decreases, more debt can be issued; if it increases, the common equity ratio would increase resulting in less debt"[14].*

FEI is not any less risky than 2012 and there are number of factors as explained in FEI's risk analysis evidence (Appendix C) that indicate FEI's business risk and particularly long-term business risk continues with an upward trend.

FEI is operating in a more challenging competitive environment than the majority of utilities included in Mr. Coyne's proxy groups. On both provincial and local levels, FEI is subject to more political risk than the majority of utilities in U.S. and Canadian proxy groups. For instance, the recently published U.S. Government's Clean Power Plan regulation recognized the importance of natural gas in reducing the greenhouse gas emissions so much so that substituting natural gas combined cycle power plants for reduced generation from higher emitting generation units is defined as one of the building blocks of the plan's implementation process[15.] In contrast, around 95 percent of BC's electricity is produced by relatively low cost hydroelectric generating stations and therefore natural gas is not viewed as an environmentally friendly solution for power generation. Detailed explanation of FEI's more challenging competitive environment can be found in FEI's business risk evidence (Appendix C).

In addition, Mr. Coyne has assessed FEI's competitive environment and has compared FEI's business and financial risk with that of U.S. and Canadian proxy groups. In his expert opinion, FEI has higher long-term business risk than the majority of utilities in his U.S. and Canadian proxy groups.

Given FEI's higher long-term business risk and lower equity ratio compared to the majority of utilities in Mr. Coyne's proxy groups and based on above mentioned Commission's definition of the link between debt issuance and long-term business risk, it is reasonable to increase FEI's current equity ratio.

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[14] GCOC Stage 1 Decision, Page 24
[15] Clean Power Plan Final Rule, at Page 27; http://www.epa.gov/airquality/cpp/cpp-final-rule.pdf

Maintaining FEI's Credit Rating in the A Category

As discussed below, maintaining a credit rating in the A category carries with it important benefits, notably in terms of the cost of borrowing, access to capital markets, and FEI's credit with its counterparties. One of the primary determinants of FEI's credit rating are its financial credit metrics, which are currently viewed by the rating agencies to be below the range acceptable for an A rating. This is driven by having a common equity ratio and allowed ROE that are both at the lower end of the range of comparable utilities. An increase in FEI's deemed common equity component will improve FEI's financial credit metrics and support the likelihood of FEI maintaining its A-category credit rating.

Securities issued by FEI are rated by DBRS and Moody's. DBRS rates debt instruments by rating categories ranging from AAA which represents the highest quality of securities, to D which represents the lowest quality of securities rated. Moody's rates debt instruments by rating categories ranging from Aaa which represents the highest quality of securities to C which represents the lowest quality of rated securities.

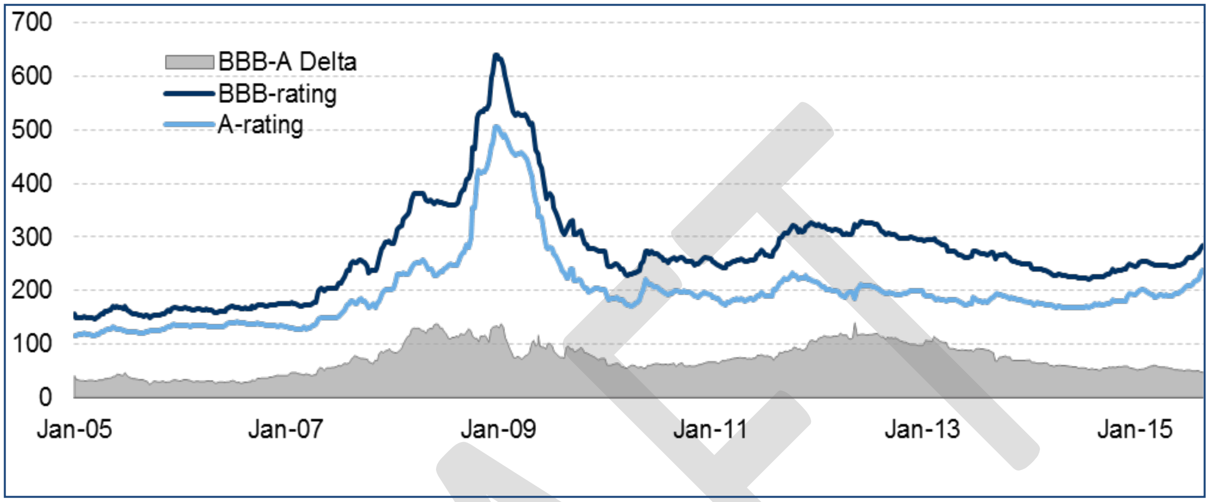
The ratings assigned to securities issued by FEI are reviewed by these agencies on an ongoing basis. Currently FEI's unsecured long-term debt is rated as "A3" by Moody's (the lowest level of the A category) and "A" by DBRS (the middle level of the A category).

As FEI carries an A3 rating from Moody's, which is one notch above a Baa1 rating and lower than its DBRS rating, a downgrade would put FEI into the BBB category for Moody's. This would result in a split-rating for FEI (that is, one debt rating in the A category and one rating in the Baa/BBB category). Investors typically focus on the lowest rating and as such would give predominant weight to the Moody's rating and consider FEI a BBB rated entity, which would have an adverse impact on FEI's cost of debt (both short-term and long-term), access to capital markets and credit with its counterparties.

i. Credit rating and cost of debt

With respect to cost of debt, the credit spread associated with a BBB credit rating category is higher than that associated with an A credit rating category. Figure XX below shows the new issue credit spreads of BBB and A-rated corporate issuers, and the difference between them, from January 2005 to August 2015. During this period, the average credit spread differential was approximately 70 basis points, with the pricing difference more pronounced during periods of market disruption (see 2008 and 2009).

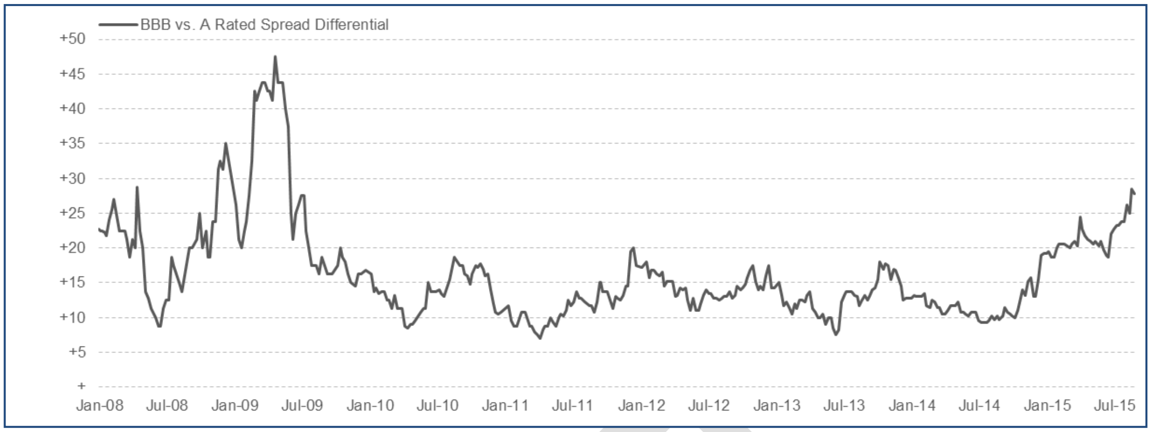
Figure xx – Indicative 30 year credit spreads of BBB-rated and A-rated new issuances



Source: RBC Capital Markets

A similar trend can be seen in the Canadian utility sector. Figure XX below, shows the incremental credit spread between the average indicative new issue spreads, on a weekly basis, of four Canadian utilities (FortisBC, Union Gas, Westcoast Energy and Nova Scotia Power) with, at a minimum a split rating, or a majority of their ratings in the BBB category and four Canadian utilities (Enbridge Gas, FortisAlberta, Gaz Metro, FEI) with all or a majority of their ratings in the A category. From January 2008 to July 2015, it can be seen that there is a significant range in credit spreads between rating categories, and this is more so during periods of market disruption, as seen in 2008/09.

Figure xx – Indicative 30 year credit spread between selected BBB/split rating and A-rated utilities

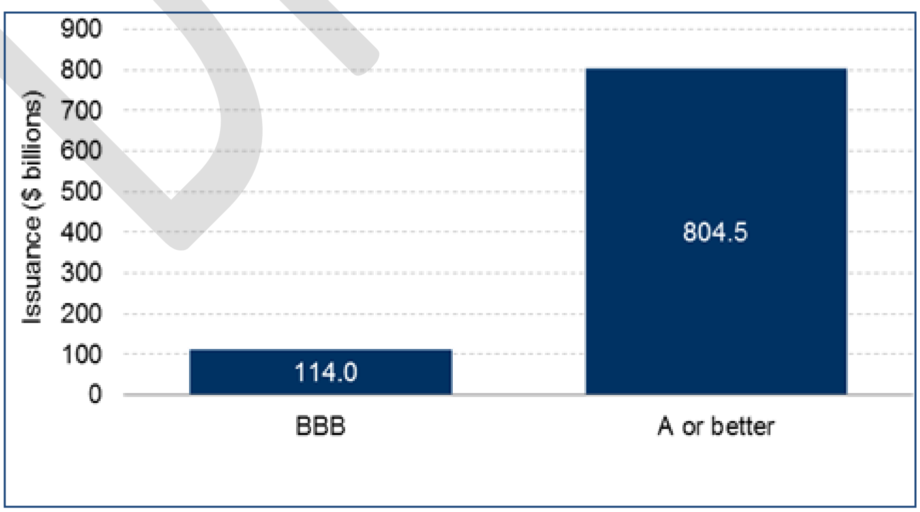


Source: Scotiabank Debt Capital Markets

ii. Credit Rating and Access to Capital Markets

In the context of debt capital markets, as illustrated in Figure xx, there is a deeper, more liquid market for A-rated bonds compared to BBB-rated bonds, with a large majority of bonds issued in the A-rating category. Many institutional investors face limits on the proportion of Baa/BBB rated debt they are allowed to hold in their portfolios. Based on research from RBC Capital Markets, approximately 88 percent of all long-term domestic corporate bonds issued from 2005 to August 31, 2015 are A-rated or higher.

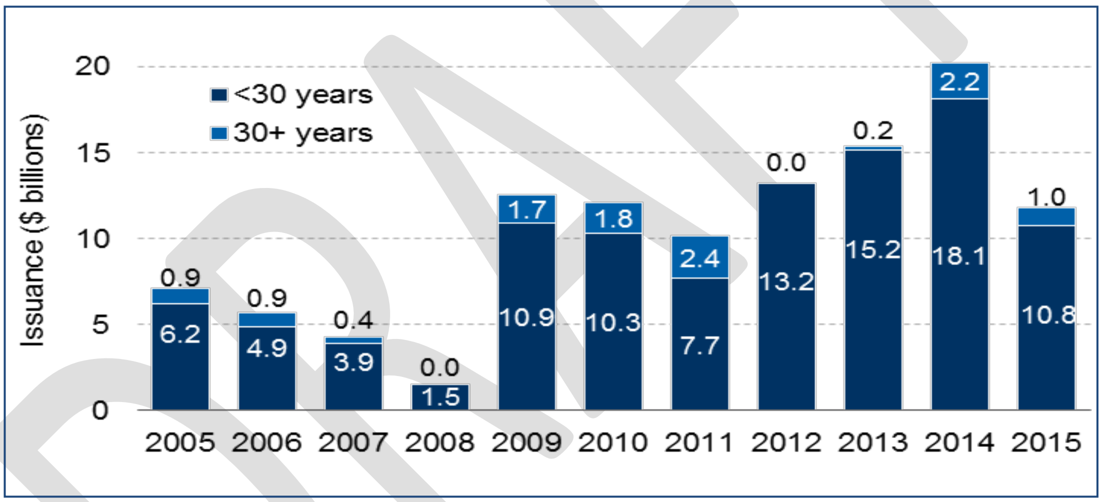
Figure xx – Corporate Bonds Issuance Volumes by Rating from 2005 to August 2015



(Source: RBC Capital Markets)

In order to match the long term nature of its regulated assets, FEI typically finances the debt portion of its capital structure with debt at terms of 30 years and longer. Issuers with Baa/BBB category ratings can be shut out of the Canadian bond markets at times, particularly during periods of market distress and for longer tenor issuances. As a regulated utility, maintaining the flexibility to access debt capital under various market conditions, and in particular for longer duration bonds, is critical. Figure XX below illustrates the limited access to 30 year and longer term bonds in the Baa/BBB category, and how access to debt capital for this category can be even more challenged in distressed markets like the one that existed in 2008.

Figure xx – BBB-rated Corporate Bonds Issuances by Year and Term from 2005 to August 2015



(Source: RBC Capital Markets)

iii.Credit Rating and FEI's credit with its counterparties

FEI's credit ratings also have significance for FEI's operations. Currently, counterparties to FEI do not require collateral in the form of letters of credit, nor has FEI experienced any restrictions on the amount of unsecured credit the counterparties have extended to FEI. This lack of restrictions to date is due in part to the FEI's A credit rating designation. A credit rating downgrade below the A rating category could lead to FEI being required to post letters of credit with its counterparties, which would add direct costs in the form of letter of credit fees and lead to a higher utilization of its debt facilities, reducing capacity on its credit facilities available to fund ongoing operations, including capital requirements.

In previous proceedings, the Commission has recognized the importance of an “A” category credit rating. For instance in 2009 Decision, the Commission panel agreed with FEI that “the combination of the equity ratio and the allowed return thereon should be adequate to attract capital on reasonable terms and conditions and allow TGI to maintain the A3 rating on its debt and unsecured debt from Moody’s.” Similarly, in the GCOC Stage 1 Decision, the Commission restated its support for an “A” category rating to the extent that is required by the Fair Return Standard:

> *“The Commission Panel is supportive of maintaining an “A” category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard.”*

FEI believes that maintaining an “A” category credit rating is essential to meet the Fair Return Standard criteria as it will help with FEI’s financial integrity and will enable FEI to satisfy its significant capital needs on reasonable terms and conditions, even under challenging economic conditions.

The capital structure and ROE are key determinants of the credit metrics that support FEI’s rating in the A category.

Table xx show Moody’s four key financial metrics and the relative position of these metrics compared to Moody’s guidelines for an A3-rated entity[16]. In the event of a decrease to deemed equity and allowed ROE, financial ratios that are weak at equity levels of 38.5% and allowed ROE of 8.75% would be further weakened and may risk a downgrade, while an increase in deemed equity and allowed ROE would alleviate some of the pressure on weak financial metrics relative to current ratings. It is worth noting that when the current rates were set as a result of the GCOC Stage 1 decision, FEI was initially placed on negative watch by Moody’s due to expected deterioration of credit metrics. The subsequent removal of the negative watch was based on Moody’s expectation of a stable regulatory environment and stable, albeit weak financial metrics. Reductions in either allowed ROE or equity thickness, while weakening metrics, may

[16] The reason for focus on Moody’s metric was articulated earlier in this section.

also lead to a reconsideration of the qualitative evaluation of regulatory support and stability of financial metrics, putting pressure on FEI ratings. The proposed increase in allowed equity thickness will lessen the risk of a credit rating action. The reaction of Moodys to the GCOC Stage 1 decision highlights the risk of the current rating, which is influenced by FEI's relatively weak credit metrics.

Table XX – FEI Key Financial Indicator Scores Compared to minimum A3 rating per Moody's Utility Rating Methodology[1,2]

	A3 - Rating Threshold[2]	2011	2012	2013	2014
CFO pre-WC + Interest / Interest	4.5x	2.3x	2.5x	2.7x	2.8x
CFO pre-WC / Debt	19.0%	11.2%	14.5%	15.1%	14.4%
CFO pre-WC - Dividends / Debt	15.0%	6.6%	9.6%	8.0%	10.3%
Debt / Capitalization[3]	50.0%	47.4%	44.0%	43.6%	45.2%

1 - Financial Metrics per Moody's Credit Opinion on July 20, 2015.

2 - Threshold between Baa-rating and A-rating per Moodys Rating Methodology for low Business Risk Entities. Source: Moody's Investors Service Rating Methodology for Regulated Electric and Gas Utilities December 23, 2013.

3 - For Debt/Capitalization %, lower scores denote higher creditworthiness.

Table XX below compares the approved capital structure and other credit metrics of a sample of Canadian utilities with those of FEI.

Table XX - Comparative analysis of utilities' credit metrics, allowed ROE and equity thickness (Source: DBRS Research)

	DBRS Rating	EBIT Interest Coverage			Debt to Total Capital			Allowed ROE			Equity Thickness		
Fiscal Year		**12**	**13**	**14**	**12**	**13**	**14**	**12**	**13**	**14**	**12**	**13**	**14**
		x	**x**	**x**	**%**	**%**	**%**	**%**	**%**	**%**	**%**	**%**	**%**
Enbridge Gas Distribution Inc.	A	2.05	2.58	2.37	55.5	55.5	60.9	8.4	8.9	9.4	36.0	36.0	36.0
Gaz Métro inc.[2]	A	2.11	1.83	1.85	63.7	65.3	67.9	8.9	8.9	8.9	38.5	38.5	38.5
Union Gas Limited[6]	A	2.35	2.48	2.59	64.2	65.1	63.7	8.5	8.9	8.9	36.0	36.0	36.0
TransCanada Pipelines Limited[5]	A	2.36	2.63	2.74	51.7	53.9	54.0	11.5	11.5	11.5	40.0	40.0	40.0
Average Natural Gas Distribution and Transportation		**2.22**	**2.38**	**2.39**	**58.8**	**60.0**	**61.6**	**9.3**	**9.6**	**9.7**	**37.6**	**37.6**	**37.6**
FortisBC Energy Inc.		**2.03**	**1.99**	**2.05**	**58.9**	**60.3**	**61.4**	**9.5**	**8.8**	**8.8**	**40.0**	**38.5**	**38.5**
FortisAlberta Inc.[1]	A(low)	2.34	2.19	2.19	57.9	57.6	56.7	8.8	8.3	8.3	41.0	40.0	40.0
FortisBC Inc.	A(low)	2.43	2.54	2.44	58.5	59.0	58.4	9.9	9.2	9.2	40.0	40.0	40.0
Hydro One Inc.[3]	A(high)	2.91	2.95	2.92	55.5	55.1	52.9	9.4	8.9	9.4	40.0	40.0	40.0
Newfoundland Power[4]	A	2.74	2.95	3.10	55.2	54.6	55.1	8.1	8.8	8.8	45.0	45.0	45.0
Toronto Hydro Corporation	A	2.44	2.50	2.64	57.2	57.6	61.2	9.6	9.6	9.6	40.0	40.0	40.0
AltaLink L.P.[7]	A	2.54	2.84	2.89	57.4	60.3	60.5	8.8	8.3	8.3	37.0	36.0	36.0
Average Electric Distribution and Transmission		**2.57**	**2.66**	**2.70**	**57.0**	**57.4**	**57.5**	**9.1**	**8.8**	**8.9**	**40.5**	**40.2**	**40.2**
FortisBC Energy Inc.		**2.03**	**1.99**	**2.05**	**58.9**	**60.3**	**61.4**	**9.5**	**8.8**	**8.8**	**40.0**	**38.5**	**38.5**

1 For assets not being funded by capital tracker revenue, Allowed ROE and Equity Thickness were set at 8.75% and 41%, respectively, for 2013 and 2014 .

2 Financials based on Gaz Métro Limited Partnership. Regulatory ratios based on Gaz Métro-QDA.

3 Allowed ROE is for transmission segment.

4 '14 data is for the 12 mos. ended June 30, 2014.

5 Allowed ROE and Equity Thickness based on Canadian Mainline. '14 data is for the 12 mos. ended March 31, 2014.

6 '14 data is for the 12 mos. ended September 30, 2014.

7 '14 data is for the 12 mos. ended March 31, 2014.

As can be seen in the above table, FEIs credit metrics are generally weaker than its Canadian peer groups. For instance, FEI's 2014 EBIT interest coverage at 2.05 is lower than the average of both the natural gas and electric distribution and transportation peer group of companies. In addition, Mr. Coyne's evidence indicates that FEI and Canadian utilities in general, have more financial risk and weaker credit metrics than the U.S. proxy group companies.

FEI's Debt Issuance Capacity Could Be Constrained

As a regulated distribution utility that is required to continually invest in its gas distribution system to serve its customers, ongoing access to capital is imperative. This is particularly the case for FEI currently, considering the capital projects underway or planned in the near future.

FEI's debt issuance capacity is mainly dependent on the Commission's approved ROE and capital structure as well as market-driven cost of debt, which itself is affected by the allowed ROE and common equity ratio. The analysis below demonstrates that FEI's long-term debt issuance capacity is becoming more constrained under its Trust Indenture. In order to protect the Company's ability to issue debt in this period of high growth, the requested increase in common equity is appropriate.

FEI's Trust Indenture governs FEI's debentures including the ability to issue new debt. The debt issuance coverage test as set out in FEI's Trust Indenture provides that FEI will not issue debentures or other debt instruments (other than First Mortgage Bonds or Purchased Money Mortgages maturing 18 months or more after the date of issue) unless Consolidated Available Net Earnings (CANE)[17] are at least 2.0 times the annual interest expense on debentures, excluding interest related to Purchase Money Mortgages (PMMs) and including the annual interest requirements on additional debt being issued. Failure to meet this test would limit FEI's ability to issue long-term debt.

For 2015, considering FEI's deemed equity component of 38.5%, ROE of 8.75% and the exclusion of interest related to PMMs, the Company's level of CANE is sufficient to allow FEI to issue long-term debt as required. The exclusion of PMM interest provides significant support for the test, as it allows FEI to finance approximately $275 million of

[17] CANE is calculated by starting with net income, and adding back income taxes, as well as interest on Funded Obligation (which is effectively interest on debt in excess of 18 months, excluding interest on PMM's and short term debt)

its total debt structure without impacting the new issuance test coverage threshold of 2.0 times.

However, FEI will begin to lose the benefit of the PMM interest exclusion as $275 million in PMMs will mature in 2015 and 2016. These maturing PMMs will be refinanced with senior unsecured debentures under the FEI Trust Indenture, whose interest, unlike the PMMs, must be included in the issuance test. The loss of PMM exclusion benefit will significantly reduce FEI's debt issuance capacity. In addition to other factors raised in this evidence, it is prudent to increase the allowed common equity component to 40% in order to mitigate the impact of the maturing PMMs on the debt issuance test and provide more certainty of access to necessary debt capital when required.

As shown in Table XX, the expiration and refinancing of PMMs will reduce FEI's issuance capacity by an estimated $137.5 million. This structural loss of issuance capacity due to PMM expiry will take place during a period when FEI is expected to undertake a number of large projects, and will be required to finance a significant amount of net capital expenditures (capital expenditures net of depreciation) partially through additional debt issuances. The table below shows the Company's debt issuance capacity compared to its debt requirements based on anticipated capital projects, taking into account the maturity and refinancing of the PMMs.

Table XX – Impact of PMMs refinancing and New Issuances on Issuance Capacity at current allowed ROE and capital structure

(CAD$ 000s)	
Status Quo Issuance Capacity[1]	733,200
Refinancing of $275 million of PMMs[2]	(137,500)
Net Status Quo Issuance Capacity before Net Capex Growth Issuances	595,700
Average Annual Debt Financing Required[3]	(358,333)
Issuance Capacity Surplus (Deficit)	**237,367**

1- Issuance Capacity in 2015 based on 2014 actual financial results, with post- amalgamation adjustments to amalgamated FEI, FEVI and FEW. Assumes allowed ROE of 8.75% and deemed equity of 38.5% for all entities

2- Refinancing of PMM maturities of $75 million in 2015 and $200 million in 2016. New issuance yield of 5.0% on refinanced debt.

3 - Expected financing requirements from 2016 to 2018 of $1.075 billion. New issuance yield of 5%. Excludes issuances related to refinancing of PMMs.

As explained earlier, the issuance capacity calculation is sensitive to the level of allowed and achieved ROE, the capital structure and the cost of debt for new issuances. Any change in ROE and/or equity ratio and/or any increase in issuance rate will further impact the ability to the Company to issue new debt when required. The impact of changes in ROE and deemed equity on issuance capacity is presented in Table XX while the issuance rate sensitivity analysis is shown in Table XX.

Table XX – Impact of Changes to ROE and Deemed Equity Levels on Issuance Capacity

(CAD$ 000s)	
Increased ROE and Deemed Equity Levels[2]	420,528
Current ROE and Deemed Equity Levels[1,2]	237,367
Decreased ROE and Deemed Equity Levels[2]	129,279

1 - Annual Issuance Capacity Surplus per Exhibit xx

2- ROE and Deemed Equity Levels of the 3 scenarios are as follows:

	Decrease	Unchanged	Increase
Deemed Equity	37.0%	38.5%	40.0%
ROE	8.50%	8.75%	9.50%

As illustrated in Table XX above, at a 5.0% percent issuance rate, an ROE reduction of 25 bps and an equity ratio reduction of 1.5 percentage points would reduce FEI's issuance capacity by approximately $108 million.

Similarly, Table XX demonstrates that an increase in new debt issuance rates has a significant impact on issuance capacity. Based on a potentially high debt issuance forecast over the next four years, FEI could be in a position of constrained issuance capacity.

Table XX – Sensitivity of Issuance Capacity to Cost of Debt (issuance rate)

(CAD$ 000s)	
Issuance Capacity Surplus[1] at 5.0%	129,279
Issuance Capacity Surplus at 6.0%	20,571
Issuance Capacity Surplus at 7.0%	(57,092)

1 - Based on a decreased ROE and Deemed Equity of 8.50% and 37.0% respectively per Figure xx.

From reviewing these results, it is evident that the loss of the PMM exclusion benefit along with the required need to finance additional debt issuances will have a significant impact on FEI's debt issuance capacity going forward. The requested changes in allowed capital structure and ROE levels would mitigate this and provide protection from capital market volatility, while any decrease in deemed equity and ROE will constrain capacity and make FEI more vulnerable to an environment of increasing debt costs.

An increase in deemed equity and/or allowed ROE in consideration of this loss of benefit would be prudent, mitigating the negative impact in issuance capacity going forward.

Conclusion of Capital Structure Discussions

As recognized previously by Commission's decisions, Canadian utilities need to compete for capital in the global market place and it is important that the regulatory agencies in Canada ensure that utilities subject to their jurisdiction are allowed a return and capital structure that enable them to do so. FEI respectfully submits that a 40 percent equity thickness is warranted considering the upward trend in FEI's business risk, the need to strengthen the Company's weak credit metrics to support the ongoing access to capital investment and potential constraints in issuing new debt under the Company's Trust Indenture Agreement and decrease in FEI's debt issuance buffer caused by refinancing the maturing PMMs with senior unsecured debentures during a capital intensive period. A 40 percent equity thickness will help FEI to remain an A-rated utility with access to capital markets under reasonable terms and conditions in all economic environments and improve FEI's ability to compete for capital with its peer companies on an equal footing.

1.8 AUTOMATIC ADJUSTMENT MECHANISM

As put forth in the 2009 Application and again in the GCOC Stage 1 Proceeding, FEI continues to believe that the use of an Automatic Adjustment Mechanism is not preferred in setting the allowed ROE for a utility, instead, a regulatory proceeding is more appropriate.

In the GCOC Stage 1 Decision, the Commission reinstituted the AAM that was eliminated by Order G-158-09 issued concurrently with the 2009 Cost of Capital Decision. In developing the parameters of the mechanism, the Commission agreed with FBCU's argument that an AAM with limited inputs cannot capture all of the complex factors affecting ROE and acknowledged that a single variable formula similar to the one used prior to 2009 does not satisfy the Fair Return Standard in a low interest rate environment. The Commission panel adopted a two variable formula similar to those adopted at the time by Ontario's and Quebec's regulators that considers the changes in both Long Term Canadian Bond Forecast (LCBF) and the changes to the utility bond spread as follows:

$$ROE = BaseROE + 0.5*(LCBF_t - BaseLCBF) + 0.5*(UtilBondSpread_t - BaseUtilBondSpread)$$

To avoid the downward bias inherent in the formula, the Commission also decided to make the application of the formula conditional upon the actual long term Canadian bond yield meeting or exceeding the 3.8 percent threshold. So far, the Canadian long term bond yield has remained well below the 3.8 percent threshold and therefore the AAM has not applied to FEI's ROE.

At the time, the Commission sought comfort in the applicability of AAMs in Quebec and Ontario and stated that "*application of similar models within both Ontario and Quebec supports it usefulness and acceptance".*

Since the GCOC proceedings, Quebec, one of the jurisdictions referred to in the Commission Decision as a successful model, has also suspended application of its own formula[18]. FEI believes that the Commission should suspend the application of the AAM in BC, instead reviewing the cost of capital for the benchmark utility in a three to five year time frame. Nevertheless, if the Commission continues to believe that an AAM is appropriate then it should continue with the two factor model approved in the GCOC proceeding, including the 3.8 percent threshold to account for the low interest rate environment.

[18] D-2013-036, D-2013-085, D-2014-078 and D-2015-076

1.9 RATIONALE FOR THE SELECTION OF FEI AS BENCHMARK

FEI has been the benchmark utility for the purposes of determining the allowed rate of return for BC utilities since 1994. In each cost of capital application since 1994, the Commission has re-examined FEI's business profile and business risk as it existed at the time, thus updating the profile of the benchmark utility. The use of a benchmark utility, and FEI's suitability for serving as the benchmark utility, were most recently re-affirmed in the GCOC Stage 1 proceeding . FEI believes that the same approach that has been used for two decades remains appropriate today. The Commission should consider the business profile and business risk of FEI as it exists today, post amalgamation, and continue to treat FEI as the benchmark utility.

Designating a benchmark utility for the purpose of establishing the cost of capital for BC utilities is efficient and encourages consistency in decisions, while still permitting the application of the Fair Return Standard. Using a real utility, rather than a hypothetical construct, permits greater understanding of the characteristics of the benchmark utility and thus permits more efficient and transparent comparisons. FEI has always been considered to be the best suited among all of the BC utilities to serve as the benchmark utility.

The Commission most recently affirmed FEI as the benchmark utility in the GCOC Stage 1 proceeding, citing similar reasons. Procedural Order G-148-12 from the GCOC Stage 1 proceeding stated:[19]

> *The Commission Panel notes that there was general agreement among the parties with respect to FEI in 2012 being made the benchmark for the GCOC proceeding. FEI is well established, of sufficient size and has a diverse customer and asset base. In addition, FEI is well understood as a utility by all the participants as it has traditionally been used as the benchmark utility in British Columbia. This and the fact that there is a substantial body of FEI related evidence already on the record in this proceeding makes FEI a reasonable candidate for the benchmark utility. Therefore, notwithstanding the various positions of the participants as to whether FEI can be described as a pure play gas distribution utility, the Commission Panel agrees with the participants and accepts FEI, in the*

[19] Order G-148-12, Reasons or Decision, p.4. The Commission affirmed this in the final Stage 1 Decision (p.114), stating: "The common equity component and the approved ROE in this Decision will serve as the benchmark cost of capital for any other utility in British Columbia that uses the benchmark utility to set rates."

present time frame, as the most appropriate choice for the benchmark utility.

FEI continues to be the logical choice to serve as the benchmark utility based on the above criteria. In particular, as was the case in 2012:

- FEI is the largest investor-owned utility in British Columbia, remains one of the largest gas distribution utilities in the country, and continues to have a relatively diverse geographic, customer and asset base.

- FEI remains representative of the general business risk characteristics facing BC utilities, facilitating comparisons with other BC utilities.

- Although FEI's equity is not publicly traded, its debt is rated by two debt rating agencies, providing some independent capital market assessment of its overall business and financial risks, albeit from a bondholder's perspective.

- The Commission, interveners and other utilities are familiar with FEI as the benchmark. Past proceedings have examined the business profile and business, regulatory and financial risks of FEI. It is more efficient to utilize the record from those proceedings as necessary, and supplement it, rather than to start over with a new benchmark. The continued use of FEI as the benchmark also allows for analysis of the changes to business risk over time, for both FEI as the benchmark as well as for each utility that benchmarks to FEI. The corporate amalgamation of the three FortisBC natural gas utilities, effective January 1, 2015, resulted in changes to certain financial and operating metrics of FEI, but did not fundamentally alter FEI's business profile. For instance, the number of customers increased, rate base increased and the constituent utilities had different customer profiles. However, FEI Amalco is fundamentally engaged in the same business as FEI had been involved in before the amalgamation. The same categories of risk or risk factors that had been applicable to FEI pre-amalgamation remain relevant for FEI Amalco. Changes in the risk assessment can all be accounted for in the business risk analysis, and do not affect the suitability of FEI to serve as a benchmark utility.

- FEI Amalco remains, and will remain for the foreseeable future, primarily a "pure play" gas distribution utility as it had been in 2012. On any objective measure, FEI's traditional customer base remains the overwhelmingly dominant component of FEI's business. Moreover, all services provided by FEI, including Natural Gas for Transportation and biomethane, represent the distribution of natural gas to residential, commercial and industrial end users.

- Pacific Northern Gas Inc. (PNG) and FortisBC Inc. are the only other sizable investor-owned utilities in the Province. FBC and PNG both lack the broad geographic scope and large customer base of FEI. There would be regulatory inefficiencies associated with moving away from a long-established benchmark utility and designating PNG or FBC as the benchmark utility.

The approach of benchmarking BC utilities to "FEI as it exists at the time of a cost of capital proceeding" has worked for almost two decades. There is every reason for the Commission to continue using that approach, and no compelling reason to change.

2. COMPANY SPECIFIC DOCUMENTS

FEI has included a number of company specific documents in Appendix A.

3. CONCLUSION

The materials filed in this Application provide the necessary evidence on which to determine the key matters at issue in the Proceeding. In determining an ROE and capital structure for amalgamated FEI that meets the Fair Return Standard, the Commission should give recognition to the current assessment of FEI's business risks, which in the view of FEI are trending higher, consideration of the need for higher equity thickness to support ongoing debt issuance and credit ratings and the ongoing challenges posed by uncertainty in financial markets.

Based on the evidence before the Commission, FEI submit that the Fair Return Standard is met in this Proceeding by having a capital structure that includes a 40% equity ratio, and a ROE of @%.

FORTISBC ENERGY INC.

Business Risk Assessment

Appendix C

FORTIS BC

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1. INTRODUCTION

The assessment of a utility's risk profile is an essential element of its cost of capital estimation process. The FortisBC Utilities (FBCU) provided a detailed description of FEI's business risk profile as Appendix H of its evidence in the Generic Cost of Capital Proceeding – Stage 1 (GCOC Stage 1). Further, a comparison of FEI's business risk profile with that of FEVI and FEW was provided as Appendix A of its evidence in the Generic Cost of Capital Proceeding – Stage 2 (GCOC Stage 2). The Companies described their overall competitive, operating, policy and regulatory environment using specific categories of business risk and risk factors.

Since the filing of evidence in GCOC Stage 1 and GCOC Stage 2, on February 26, 2014 by Order G-21-14, the Commission approved the amalgamation of FEI, FEVI and FEW. On May 23, 2014, the Lieutenant Governor in Council issued Order in Council No. 300 consenting to the amalgamation. The amalgamated entity is carrying on business as FEI, and in this appendix will be referred to as "FEI", "the amalgamated FEI" or "FEI Amalco", as appropriate.

This Appendix describes amalgamated FEI's overall competitive, operating, policy and regulatory environment using the same categories of business risk and risk factors that had been used in the Companies' GCOC filings. FEI assesses any changes to its risk profile from two perspectives:

1. FEI has assessed how its risk profile has changed in comparison to risks defined in GCOC Stage 1 as a result of factors other than the amalgamation itself. The analysis addresses, for instance, changes in commodity prices or regulatory and political developments since 2012.

2. FEI has also considered the extent to which FEI's risk profile has changed as a result of amalgamating with FEVI and FEW. In GCOC Stage 2, the FBCU stated that FEVI's and FEW's risk profiles were higher than that of FEI due primarily to (a) greater concentration of assets within a small service area, (b) less diverse customer and economic base, (c) greater challenge in terms of price competitiveness and (d) greater supply security risk due to regional infrastructure constraints and dependency on a single pipeline system that traverses challenging terrain. Amalgamation has addressed items (a), (b) and (c), for the most part[1]; however, item (d) represents an incremental risk for the amalgamated FEI in comparison with GCOC Stage 1. In addition, the effect of amalgamation on other elements of FEI's business risks will be considered in this section.

Amalgamated FEI's overall business risk is best characterized as being similar to that of the 2012 benchmark utility (pre-amalgamation FEI) and trending higher.

[1] Until January 1st 2018 when the phase-in period will be completed, the Vancouver Island and Whistler service areas continue to have higher delivery rates than the Mainland.

2. OVERVIEW OF BUSINESS RISK

2.1 Generic Business Risk Categories and Factors

In the GCOC Application, FEI identified eight business risk categories, as presented in Table 1 below. FEVI and FEW used the same categories in Stage 2 of the GCOC proceeding. Other risk factors and categorizations are possible, and some risk factors could be captured under a different risk category.[2] However, using the same categories as in the GCOC proceeding facilitates the comparison of the amalgamated FEI risk profile with business risk information presented during the GCOC proceeding.

Table 1: Business Risk Categories and Risk Factors Addressed in this Appendix

Business Risk Category	Risk Factors
Business Profile	• Type and size of utility • Energy product offering • Service area and 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 capture rates
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 uncertainty and lag • Deferral accounts • Administrative penalties

[2] For example, availability of energy supply could also be included as a risk factor under Energy Price because the availability of supply of an energy form can impact its price.

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2.2 Summary Assessment of Amalgamated FEI's Business Risk

Table 2 ranks the business risk categories as they apply to the amalgamated FEI and by providing a summary assessment of whether the risks to amalgamated FEI associated with particular risk factors is higher/lower/same as it was for the benchmark utility (FEI prior to amalgamation). The ranking of the risk categories provided below is identical to what was provided in GCOC Stage 1, with regulatory risk being the highest risk, followed by the risk categories most directly influencing throughput, and then other risk categories relating to operations and supply.

Table 2: Amalgamated FEI's Business Risk as Compared to 2012 Benchmark Utility

Business Risk Category	Risk Factor	Total Risk status since 2012, (all business changes incl. amalg.)	Risk status change due to amalgamation alone	Ranking of risk
Regulatory		**Same**		**1**
	Regulatory uncertainty and lag	Same	Same	
	Deferral accounting	Same	Same	
	Administrative penalties	Same	Same	
Energy Prices		**Same**		**2**
	Commodity prices	Lower	Same	
	Commodity price volatility	Higher	Same	
	Upfront and installation cost	Same	Same	
Market Shifts		**Same**		**2**
	New technology and Energy forms	Same	Same	
	Perception of energy	Same	Same	
	Housing types	Same	Same	
	Changes in energy use	Same	Same	
	Changes in the capture rates	Same	Same	
Political		**Higher**		**2**
	Energy policy and legislation	Same	Same	
	GHG emissions reductions initiatives and local governments policies	Higher	Same	
	Carbon tax	Same	Same	
	Aboriginal rights	Higher	Same	
Business Profile		**Same**		**2**
	Type and size of the utility	Same	Same	
	Energy product offering	Same	Same	
	Service area and customer profile	Same	Same	
Economic Conditions		**Same**		**2**
	Overall economic conditions	Same	Same	
Operating		**Same**		**3**
	Infrastructure integrity	Same	Same	
	Third party damages	Same	Same	
	Unexpected events	Same	Same	

Business Risk Category	Risk Factor	Total Risk status since 2012, (all business changes incl. amalg.)	Risk status change due to amalgamation alone	Ranking of risk
Energy Supply		**Higher**		**4**
	Availability of supply	Same	Same	
	Security of supply	Higher	Higher	

The key points from this "snapshot" regarding the relative risk of amalgamated FEI compared to 2012, which are discussed throughout this Appendix, are:

- The Commission's jurisdiction is confined to what is conferred by the *UCA,* but within that framework has significant discretion in the exercise of those powers. FEI is dependent on regulatory approvals of rates that determine its revenues and cost recoveries. The Commission establishes the level of return that is allowed to be included in rates, and establishes depreciation rates that determine a utility's ability to recover invested capital. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty which in itself gives rise to the risk that the allowed return does not accord with the fair return standard, that rates are set at a level that does not provide FEI with an opportunity to earn its fair return, or that necessary investments are not approved. Compared to previous periods, the 2014 PBR Decision included some additional regulatory uncertainty and risk, although the broader regulatory constructs that supported FEI's characterization of regulatory risk in 2012 remain in place. FEI has thus assessed its overall regulatory risk as being similar to what it was in 2012, with the potential to be higher over the term of PBR.

- The risk relating to energy prices overall remains similar to how it was characterized by FEI in 2012. While market prices are currently similar to where they were at this time in 2012, medium and long term commodity price forecasts are lower than what was expected in 2012 due to higher reserve expectations and lower production costs However, market prices continue to remain very volatile, despite the abundance of gas supply driven by shale gas production growth. In its 2013 decision, the Commission concluded that the forward price curve at that time indicated some level of stability over the next few years.[3] This has not been the case, as was highlighted by the price spikes and volatility that occurred during winter 2013/14 and subsequent fall in gas prices in 2015. In terms of competitiveness, the current price competitiveness of natural gas versus electricity has improved on an operating costs basis as electricity rates have increased relative to FEI natural gas rates. However, the upfront and installation costs have not changed significantly for natural gas versus electricity and this,

[3] BCUC Decision regarding Generic Cost of Capital (Stage 1), May 10, 2013, page 32.

along with other non-price factors, continues to add to the challenge of maintaining FEI system throughput levels. All things considered, overall FEI assesses that the risks associated with energy price as similar to that of its 2012 assessment levels.

- The market shift in energy demand caused by the continued support for the new energy forms and technologies that produce energy closer to the point of consumption, along with rate of change in housing mix and customer perception of energy, all continue to represent challenges to retaining and attracting customers even in the current energy price environment. Similar to 2012, the declining trend in FEI's throughput level, particularly for residential sector can be explained twofold: (a) weak capture rates in new construction market in the growing multi-family dwelling sector and (b) declining use per customer from existing and new customers caused by smaller average dwelling size as well as improvements in energy efficiency and conservation efforts supported by the provincial and local governments' policies.

- Government policies and regulations have a significant impact on FEI's operations and competitiveness. The overall thrust of climate change and energy policies remains similar to that articulated in 2012. With the passage of time, these policies have been implemented to a greater extent. Similar to 2012 provincial government's policies continue to discourage the use of natural gas in FEI's traditional markets of space heating and water heating while promoting the role of natural gas in transportation sector and LNG export. Further local governments and municipalities have intensified their "green initiatives" and in some instances have introduced updates to their bylaws and codes or have supported development of projects that can substantially hinder FEI's ability to attract new customers and/or retain existing ones. For instance, FEI's capture rates (in both commercial and residential sectors) are particularly threatened by the recent City of Vancouver decision to support mandatory connection for entire neighbourhoods to district energy systems such as the case of the active endorsement of Creative Energy CPCN. On the subject of Aboriginal rights and title issues, the recent Supreme Court of Canada Decision in *Tsilhqot'in Nation v. British Columbia* introduced new uncertainties. Overall, political risk is assessed as higher.

- The amalgamated FEI has a larger customer base and service territory than the 2012 benchmark utility. The business profile of the amalgamated entity is not materially different from FEI's pre-amalgamated business risk profile level. This viewpoint has been confirmed by credit agencies such as DBRS[4].

[4] Please refer to DBRS's January 2015 FEI's rating report.

- The current Canadian economic environment continues to be dominated by uncertainty. A combination of factors from the recent drop in oil prices and a slow-down in economic growth in Europe and China to weaker Canadian dollar and a strong U.S. recovery lead to the assessment that the overall economic condition is not materially different from 2012 levels.
- Operating risk factors include infrastructure integrity, third party damages and unexpected events. All things considered, the overall operating risk is assessed to be similar to 2012.
- Despite the abundance of supply associated with the development of tight and shale gas resources, the underlying infrastructure to move this natural gas to FEI's service territory (accessibility of supply) remains unchanged as compared to 2012. The development of several significant gas transmission infrastructure projects connecting BC deposits with Alberta and eastern markets in the coming years could alter the amount of gas available to FEI and the historical pricing relationship of BC supply in relation to Alberta production. This could have a negative impact to the price that consumers pay for natural gas in BC in the coming years. The addition of FEVI and FEW to amalgamated FEI's service territory has slightly increased FEI's exposure to security of supply risk. As such, the overall risk is considered to be slightly higher than 2012 levels.

Considered together, amalgamated FEI's overall business risk is best characterized as being similar to that of the 2012 benchmark utility (non-amalgamated FEI) and trending higher.

3. BUSINESS PROFILE

As business risk is specific to a particular utility, it is important to understand the fundamental characteristics (or business profile) of the utility being assessed. Discussed below is a high level overview of amalgamated FEI's business profile.

In 2012, the benchmark utility FEI was a large natural gas distribution utility whose core business was serving space and water heating load in the residential and commercial sectors. FEI also served industrial load. The core market was experiencing declining throughput levels and slow customer growth, while facing continued competitive challenges, which were central to its overall business risk.

Following the amalgamation of FEI, FEVI and FEW on December 31, 2014, the amalgamated FEI remains a large natural gas distribution utility. Its operations now extend to three service areas of the Mainland, Vancouver Island and Whistler, serving more than 970,000 customers throughout the province. However, its core business remains serving space and water heating load in the residential and commercial sectors. As before, the core market is experiencing declining throughput levels and slow customer growth, while facing continued competitive challenges, which are central to its overall business risk.

For comparability and presentation purposes, the FEI amounts shown for the years prior to 2015 have been restated to include FEVI and FEW, unless otherwise noted.

Table 3 summarizes FEI Amalco's overall business profile.

Table 3: Amalgamated FEI's Business Profile[5]

Type of Utility	Local Distribution Company
Energy Product Offering	Natural gas, biomethane, propane[6]
Service Area	Mainland, Vancouver Island and Whistler
Rate Base	$3,665 million
Sales/Transportation Volumes	176,035 TJ
Average Number of Customers	970,389
Net Customer Additions	10,739
Customer Growth Rate	~1%
Customer Profile by Demand	
Residential	42%
Commercial	32%
Industrial	26%
Customer Profile by Sales Revenue	
Residential	60%
Commercial	33%
Industrial	7%

- Residential includes Rate Schedule 1. Commercial includes Rate Schedules 2, 3, 23
- Industrial includes Rate Schedules 4, 5, 6, 7, 16, 22, 25, 27, 46
- With exception of rate base amount, all the numbers are presented for non-bypass customers only. Bypass Transportation volume equals 31,352 TJs and Revenue equals $29,802 thousand

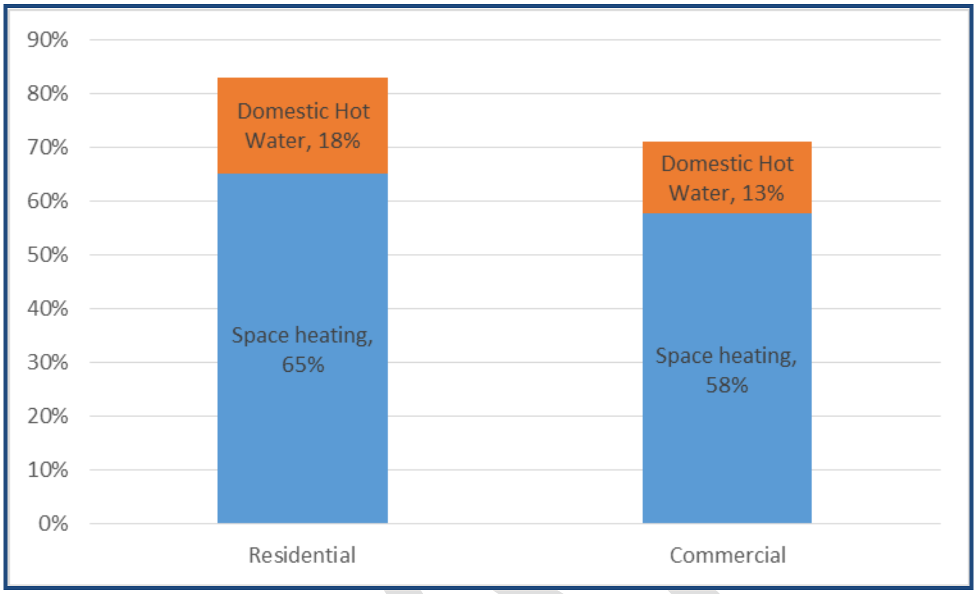
The fact that the majority of FEI's delivery margin revenue is generated from residential customers (i.e. Rate Schedule 1) is significant because FEI faces its greatest challenges[7] in the residential market.

Figure 1 below demonstrates that in FEI's residential and commercial sectors, space and water heating are the dominant end uses, accounting for about 83 percent and 71 percent of the energy consumption respectively for each sector. The most recent information is from 2011 and consolidated information for FEI, FEVI and FEW

[5] Based on FEI's 2015 Annual Review Compliance Filing dated June 30, 2015
[6] FEI also serves propane customers in Revelstoke.
[7] For instance the impact of the provincial and local governments' policies on the gradual decline of the natural gas share in the water and space heating markets is more pronounced for residential sector.

(collectively, the "FEU") has been presented (as opposed to FEI separately) to provide a better indication of FEI Amalco's profile today.

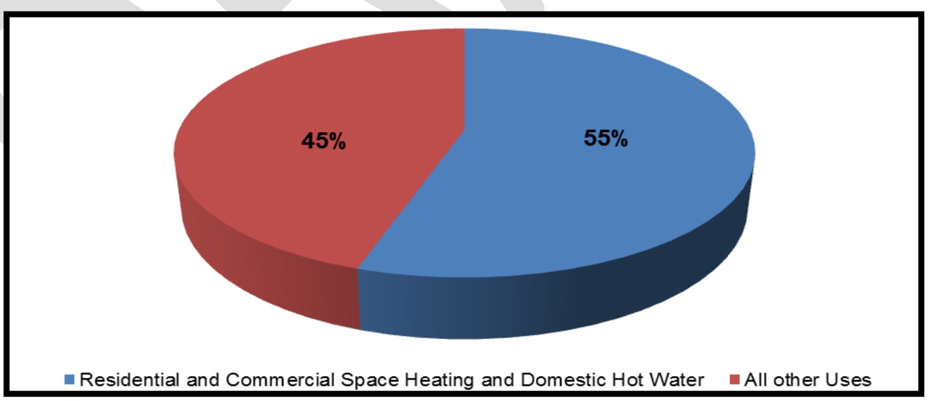
Figure 1: Residential and Commercial Consumption by End Use (2011 – Consolidated FEU Data)



Source: 2014 LTRP

Thus, the space and water heating market in residential and commercial applications is FEI Amalco's largest market for natural gas, as shown in Figure 2 below.

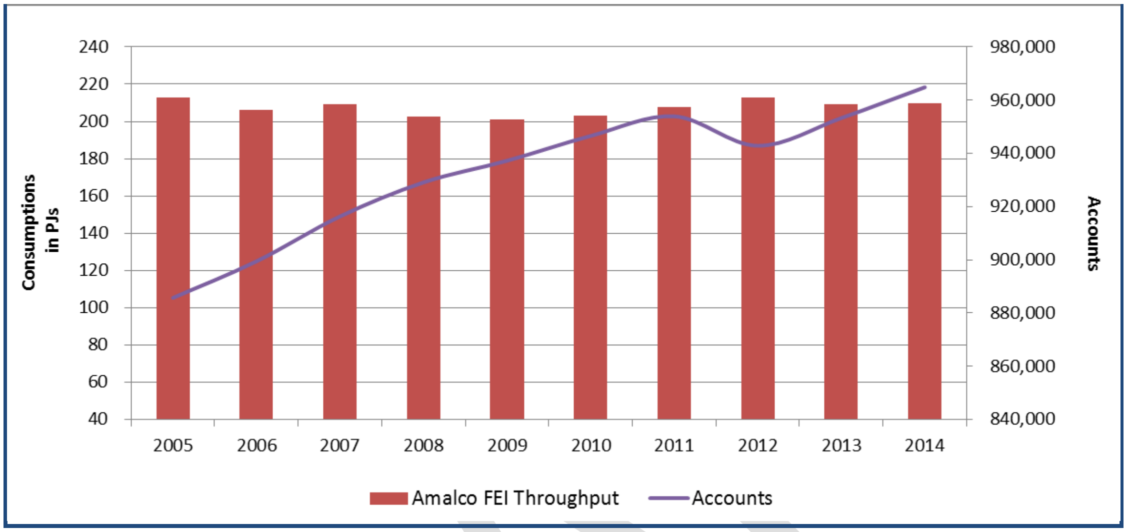
Figure 2: Total Consumption by End Use (2011 – Consolidated FEI, FEVI and FEW Data)



Source: 2014 LTRP Scenario zero

As demonstrated in Figure 3, despite adding a modest number of residential customers in recent years, the amalgamated FEI's total throughput has remained almost the same as in 2005. Indeed, in 2014, amalgamated FEI's normalized demand has experienced a modest decrease compared to the 2012 levels. Industrial throughput variations are one of the large contributors to the annual variations in total normalized throughput. This arises from industrial customers' price sensitivity and the effects of business cycles as well as continuing efforts by industrial customers to improve the energy efficiency of their operations[8]. In the long-run the direction of industrial demand will be dependent on competitiveness of natural gas to alternatives for each industrial customer and the economic conditions of specific industries.

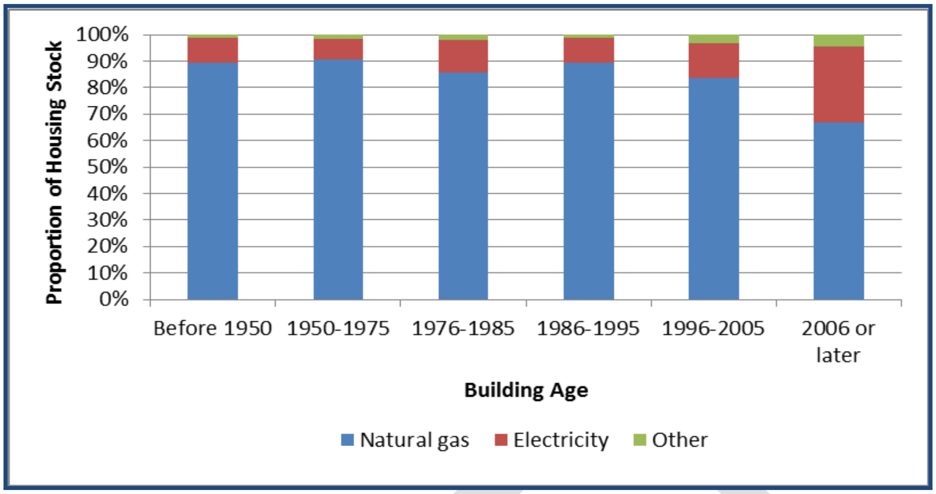
Figure 3: Amalgamated FEI's Total Throughput (Normalized Demand vs. Customer Accounts)



The use of natural gas as a main space heating fuel is diminishing while the use of electricity as a main heating fuel is on the increase. According to the 2012 Residential End-use study (REUS), new homes with gas service are less likely to use natural gas as a main space heating fuel and more likely to use electricity when compared to the stock of natural gas connected homes built prior to 2006. Figure 4 below illustrates the main space heating fuel trend by dwelling age.

[8] BC's cement industry illustrates these factors. Cement manufacturers exhibit positive cross-price elasticity of demand between natural gas and coal, meaning if the price of natural gas goes up, the demand for coal will increase. For instance a major cement manufacturer in Delta, BC, decreased its consumption from 1.719 PJs in 2012 to only 0.244 PJ in 2014 partly due to the increase in natural gas prices between 2012 and 2014. This same customer is now forecasting an increase in usage for 2016. Canadian cement manufacturers are signatories to the Cement Sustainability Initiative of the World Business Council for Sustainable Development, which aims at curbing carbon emissions from its existing production and companies, are increasing their use of alternative fuels to hit BC's goal of 40 per cent alternative fuels.

Figure 4: Natural Gas Use for Residential Space Heating

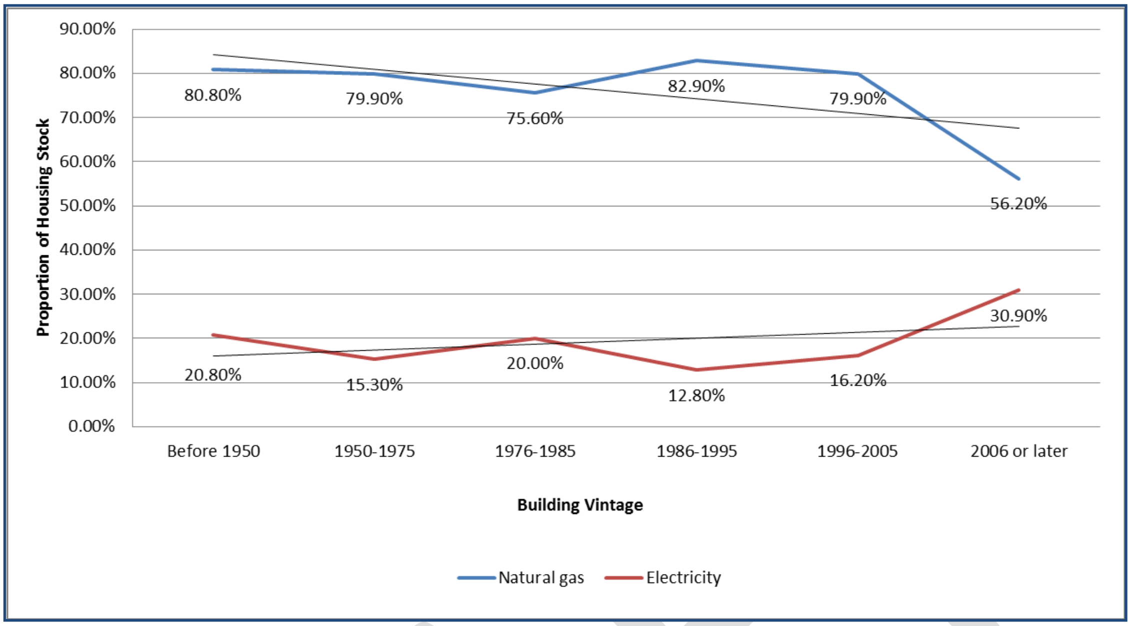


Source: 2012 Residential End-use study

The above trend regarding the energy source used for space heating in housing stock of newer vintages is significant because the share of natural gas heated homes with respect to homes built since 2005 has eroded in light of increasing use of other energy forms, primarily electricity. The percentage of new homes using electricity for space heating in the surveyed population has increased which is consistent with FEI's conclusions in the market shift risk section, that FEI continues to lose market share to electricity in the space heating sector. The increasing share of electricity use in space heating is also validated by BC Hydro's 2012 residential end-use study.

The same trend is occurring for Domestic Water Heating (DWH), which constitutes the second largest share of natural gas use for residential customers (accounting for approximately 18 percent of total residential natural gas use). According to the 2012 REUS, new homes with gas service are less likely to use natural gas fired DWH and more likely to use electricity compared to the stock of homes built prior to 2006. Figure 5 below illustrates the trend in DWH fuel by dwelling age. Natural gas use for domestic water heating in new homes has continued to decrease compared to the 2010 data which demonstrates FEI's continuing challenges in capturing new customers in this sector.

Figure 5: Trend in Residential Domestic Water Heating Fuel by Dwelling Vintage

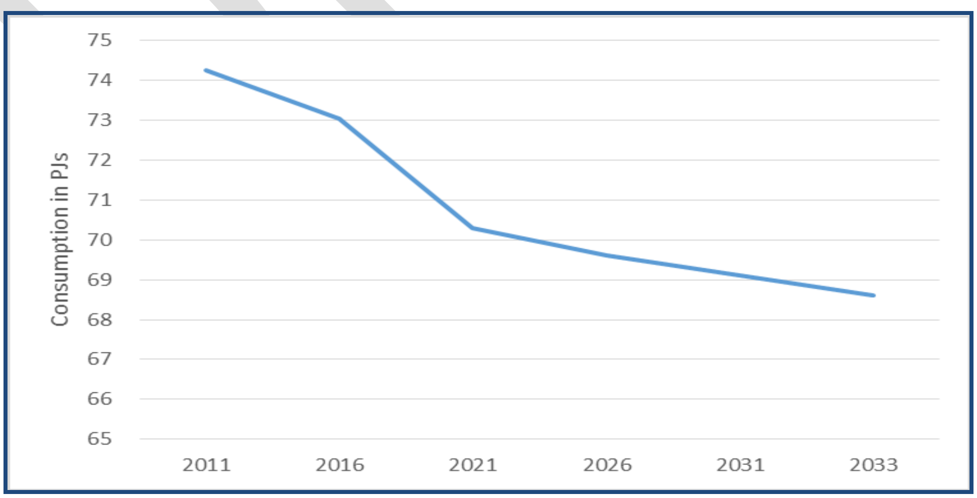


Note: Numbers not additive because some homes may have more than one DWH fuel. Don't knows (DKs) and no responses (NR) are excluded.

The underlying reasons for the declining trend in natural gas use in residential water and space heating sectors will be further explained in market shift risk and political risk sections of this appendix.

As space heating and domestic hot water heating together account for over 80 percent of total residential natural gas consumption, the declining trends discussed above will negatively impact throughput and load growth. Figure 6 shows the most likely scenario for throughput levels in the residential sector in the years to come.

Figure 6: Outlook of Amalgamated FEI Residential Throughput Levels



Source: 2014 LTRP – Residential Sector

FEI has, in recent years, responded to the changing energy environment in BC and declining throughput in its core business by undertaking new initiatives. One of those initiatives, Natural Gas for Transportation (NGT), has been identified as a potential new source of load outside of FEI's core market. Table 4 provides an estimate of the additional volumes forecast to be added to the system as a result of Greenhouse Gas Reduction (Clean Energy) Regulation incentive funding and overall efforts to add NGT load to the system.

Table 4: FEI's NGT Demand Forecast (2015-2017)

Demand Volumes (GJ)	2015	2016	2017
CNG Demand	480,000	586,000	616,000
NGT - LNG Demand	435,000	1,560,000	3,847,000
Total NGT Demand	915,000	2,146,000	4,463,000

A continuation of the current low oil prices may hinder FEI's efforts to expand the NGT demand in its service territory.

NGT volumes are a favourable development for customers in terms of representing a revenue stream. However, they do not materially affect FEI's overall risk profile. For instance, FEI's NGT demand for 2015 is forecast to be around 0.917 PJ which represents less than 1 percent of amalgamated FEI's total throughput. Even if NGT expands to its potential over the next few years, its share of total throughput would remain relatively small.

In addition to the NGT initiative, FEI is also exploring the possibilities of expanding its LNG business for regional export markets, remote communities and power generation[9]. For 2015, this mainly includes the LNG transported from Tilbury to Yukon and Northwest Territories for power generation as an alternative to diesel-fuel with a forecasted annual demand of 87,000 GJ.

Along with the above mentioned initiatives, FEI has also been active in advocating for establishment of appropriate frameworks for addition of potentially large new industrial loads from the Tilbury phase 1B expansion project and Woodfibre project for LNG export. The amendments to Direction No.5 provided some clarity regarding the rates and tariffs for these potential large industrial clients. Nevertheless, there is still uncertainty as to whether some of the proposed projects will proceed. FEI expects that these new initiatives and the investment in new infrastructure to serve them would bring some benefits to existing customers, but will not fundamentally change the core business of FEI.

In summary, FEI remains a natural gas transmission and distribution company with its current core business continuing to be natural gas distribution for space and water heating and will remain so for the foreseeable future even with additions of forecasted

[9] The incremental LNG load for both NGT-related and other LNG demand will be supplied from the Tilbury phase 1A expansion project which will add an additional 1.1 PJ of LNG storage and about 34,000 GJ per day of liquefaction capacity. For more information regarding the Tilbury expansion project please refer to the political risk section.

NGT and other LNG load that may occur. Attracting and retaining customers in the traditional heating markets remain a critical undertaking, and a key challenge, for FEI.

4. ECONOMIC CONDITIONS

Economic conditions can impact the ability of utilities like FEI to attach new customers and retain customers or maintain throughput levels, in addition to affecting utility access to capital in the manner discussed in Appendix B. The current Canadian economic environment continues to be dominated by uncertainty. The recent drop in global oil prices has negatively impacted GDP growth in oil-producing regions. Other provinces are also impacted indirectly through reduced trade with the oil-producing provinces. Further, economic and financial conditions external to both Canada and BC (i.e. slowdown in economic growth in China, re-emergence of Eurozone crisis) have the potential to affect Canada's and BC's economic outlook. Nevertheless, the weaker Canadian dollar and a relatively strong U.S. recovery have the potential to improve export opportunities and partially mitigate some of these challenges. Therefore, compared to 2012, FEI assesses the risk related to economic conditions as similar.

Table 5 summarizes the changes in leading economic indicators for four jurisdictions across Canada.

Table 5: Economic Indicators for Four Jurisdictions in Canada (2012 to 2016)

	2012	2013	2014	2015	2016
British Columbia					
Real GDP (% change)	2.4	1.9	2.7	2.2	2.5
Unemployment (%)	6.8	6.6	6.1	6.0	5.8
Housing starts (1000 of units)	27.5	27.1	28.3	26.7	27.1
Alberta					
Real GDP (% change)	4.5	3.8	4.5	-0.9	2.0
Unemployment (%)	4.6	4.6	4.7	5.9	6.1
Housing starts (1000 of units)	33.3	36.1	40.5	36.5	35.9
Ontario					
Real GDP (% change)	1.7	1.3	2.2	2.1	2.5
Unemployment (%)	7.9	7.6	7.3	6.8	6.5
Housing starts (1000 of units)	77.4	60.9	58.3	66.4	68.8
Quebec					
Real GDP (% change)	1.5	1.0	1.4	1.7	2.1
Unemployment (%)	7.7	7.6	7.7	7.5	7.4
Housing starts (1000 of units)	47.2	37.6	38.9	38.2	38.2

Shaded area represents forecast data (2014 real GDP numbers are estimates).
TD Economics, July 2015, retrieved from:
http://www.td.com/document/PDF/economics/qef/ProvincialEconomicForecast_July2015.pdf

Focusing on BC, the real GDP gains in BC are forecast to remain close to the 2012 level. Further, compared to 2012, BC's unemployment rate has slightly improved and is forecast to be around the six percent mark.

Housing starts are an important variable in determining residential customer additions. As seen in Table 5, BC is expected to be faced with a continued period of lower housing starts with a forecast of a close to 6.0 percent decline in housing starts in 2015. Lower projected housing starts can be expected to make it more difficult for FEI to add new customers and throughput.

5. ENERGY PRICE RISK

Energy prices impact utility business risk because price is among the factors that can influence consumer energy choices. Electricity remains the primary alternative available in British Columbia for space and water heating.[10] There are a number of factors that impact the price competitiveness of natural gas in BC relative to electricity.[11] They include:

- natural gas commodity cost;
- natural gas price volatility; and
- relative installation costs of gas appliances compared to electric appliances.[12]

While energy price remains a driver of business risk, recent experience suggests that other non-price considerations such as GHG emissions, type of housing mix and the size of new dwellings, customer perceptions and government policy, particularly local governments' support for non-fossil fuel alternatives through updates to building codes and bylaws, (discussed in subsequent sections) are taking on greater importance in the decisions of energy consumers.

FEI's assessment is that the overall energy price risk is similar to 2012 levels. While the commodity price risk is slightly lower, price volatility risk is higher than FEI's assessment in 2012 and significantly higher than the level assessed by the Commission in the GCOC Stage 1 proceeding. The risk associated with upfront and installation cost is considered to be similar. Amalgamation had no material impact on energy price risks.

[10] In this document, the references to electricity as an energy source in British Columbia mainly relate to BC Hydro, which delivers nearly 95 percent of electricity within the province.

[11] This was recognized by the Commission in its 2009 ROE and Capital Structure Decision, page 36, where the Commission stated: "…natural gas' competitive edge over electricity is dependent on too many significant variables, such as the level of the carbon tax, the volatility of natural gas prices and the impact of government policy on BC Hydro's rates, to be considered permanent".

[12] Builders and developers surveyed in the 2010 RNHS study have attributed the decline of gas water heating to regulation (i.e. changes in building codes) for gas furnaces such as the requirement to install more costly high efficiency units.

5.1 Commodity Price

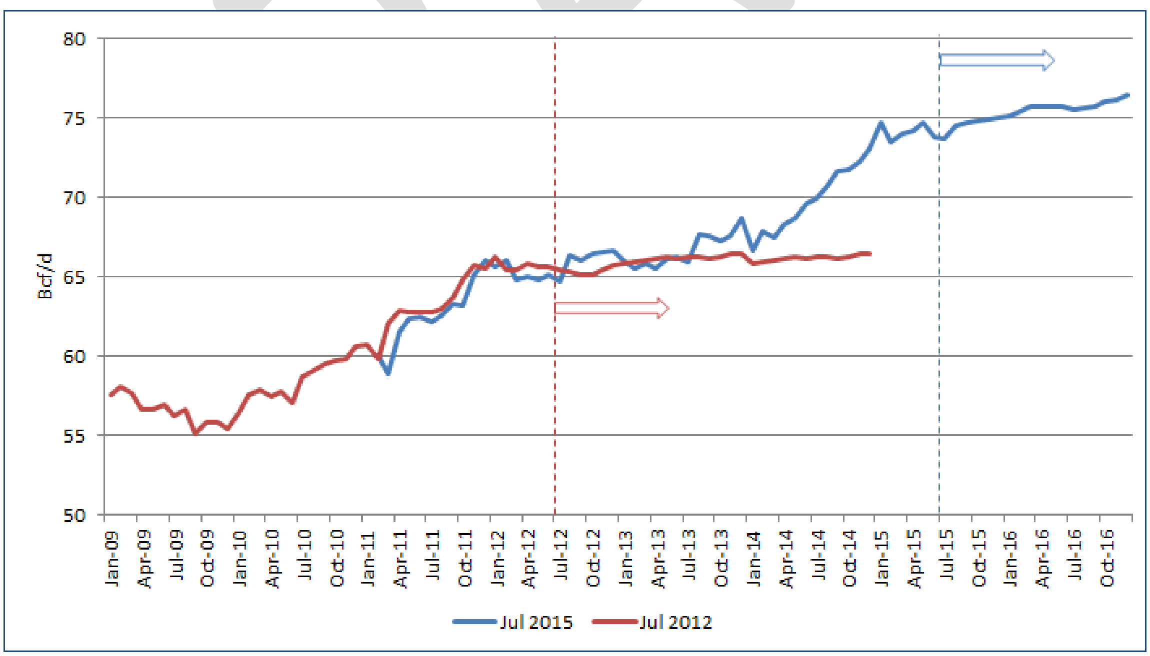
This section addresses the commodity price of natural gas and how it affects FEI's competitive position. While natural gas commodity prices are set by the market, electricity prices are heavily influenced by BC Hydro's low embedded costs, making it more difficult for FEI to compete against electricity than gas utilities in some other provinces. Natural gas competitiveness in BC is further challenged by the implementation of the BC carbon tax as well as other non-price factors.

Natural Gas Commodity Prices

In general, commodity rates in the natural gas utility sector reflect the utility's cost of purchasing the gas on behalf of its customers, without mark-up. Natural gas prices are set in an open and competitive market and are influenced by many variables throughout North America, as well as each utility's operating region. Commodity rates will therefore fluctuate in response to changes in supply and demand conditions for natural gas.

As in 2012, the current North American natural gas marketplace continues to be heavily influenced by the abundance of shale gas supply. Continued advances in drilling technology associated with shale gas and the upsurge in associated natural gas supply from increased oil production in the past few years have resulted in an oversupplied natural gas market. U.S. dry gas production has increased significantly since 2012 and reached 73.6 Bcf/d in June 2015 compared to 64.8 Bcf/d in June 2012. The figure below compares the U.S. dry gas production forecasts from July 2012 and July 2015.

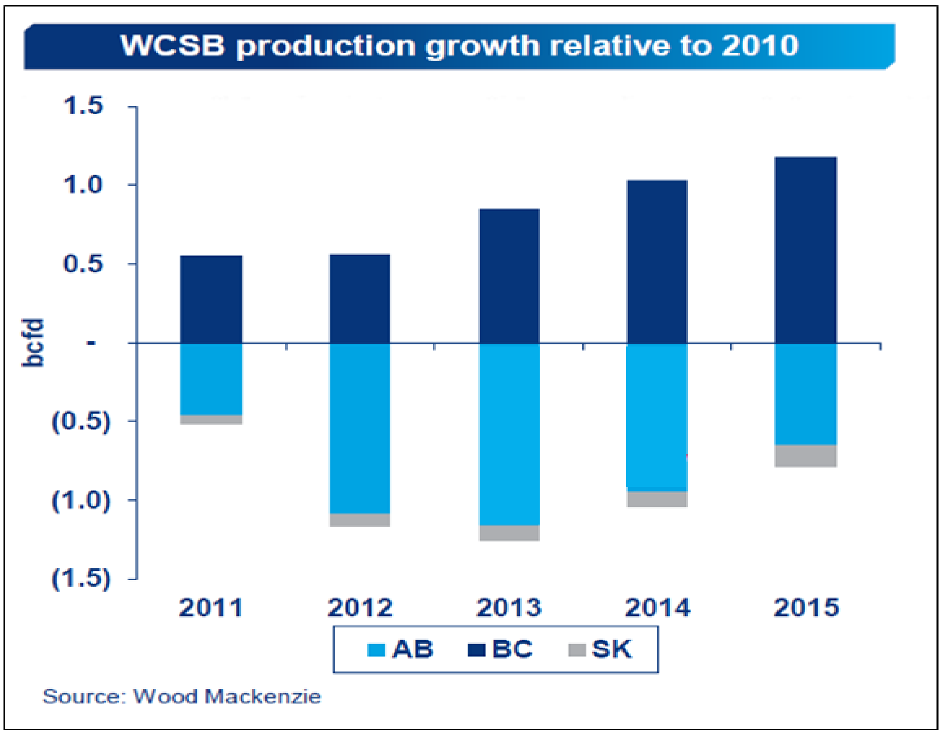
Figure 7: U.S. Dry Gas Production (Actual and Forecast)[13]



[13] EIA - Short-Term Energy Outlook – July 2012 and July 2015

This supply growth has also occurred in BC as natural gas producers have ramped up production to prove up reserves and ensure that supply is confirmed ahead of any potential LNG export demand or other projects that may come online in the future. However, overall the production in the Western Canadian Sedimentary Basin (WCSB) has been flat as declines in Alberta and Saskatchewan production levels have more than offset the increases in BC production. The following figure shows the recent growth in BC, Alberta and Saskatchewan gas supply within the Western Canadian Sedimentary Basin (WCSB)[14] over the last five years.

Figure 8: WCSB Production Growth[15]



The continued growth has helped contribute to low market prices for natural gas on a North American basis. In Northeastern BC, infrastructure development to connect new supply to markets has lagged behind the supply growth resulting in even greater downward pressure on prices at Station 2[16]. Figure 9 below illustrates the AECO/NIT[17]

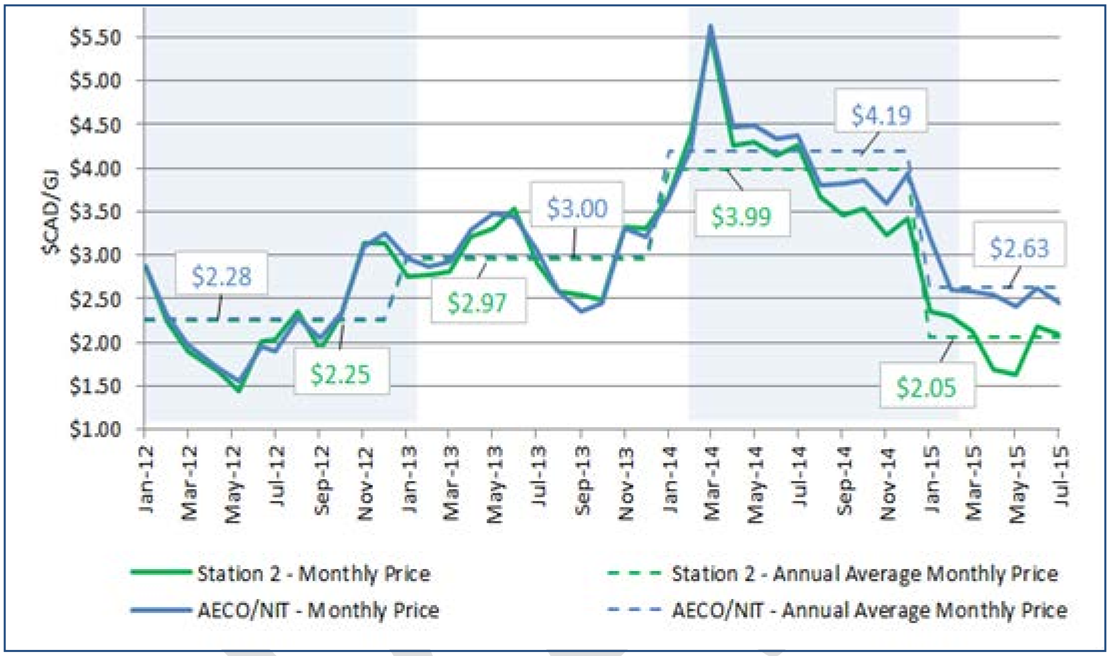
[14] Wood Mackenzie North American Gas Markets Annual Update, December 9, 2014, slide 20,[15] The National Energy Board Short-term Canadian Natural Gas Deliverability 2015-2017 - Energy Market Assessment, Figure C1, Appendix C, June 2015.

[15] The National Energy Board Short-term Canadian Natural Gas Deliverability 2015-2017 - Energy Market Assessment, Figure C1, Appendix C, June 2015.

[16] Station 2 is the main natural gas trading hub in northern BC. Natural gas produced in northern BC is traded here and then moved to markets further south or east into Alberta and US markets.

and Station 2 monthly prices from January 2012 to July 2015. While AECO/NIT prices are higher than they were in 2012, Station 2 prices are currently lower than they averaged in 2012 as the basis differential between AECO/NIT and Station 2 has widened. As discussed in Section 7, as the market rebalances (e.g. through greater pipeline connectivity) the differential between Station 2 and AECO/NIT will tighten again.

Figure 9: AECO/NIT and Station 2 Natural Gas Monthly and Annual Average Prices

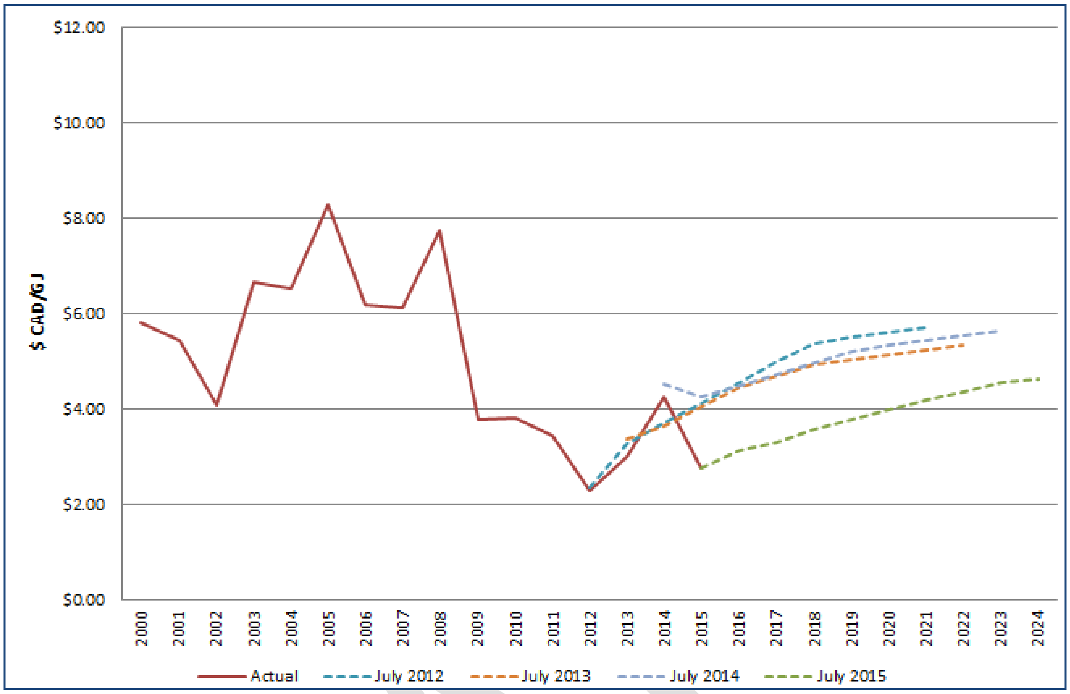


FEI purchases a mix of AECO/NIT price based monthly supply in Alberta and at Station 2, and and daily priced supply at both AECO/NIT and Station 2 to meet its customer requirements. Therefore, when looking at both AECO/NIT and Station 2 prices together, actual market prices are similar in early 2015 to where they were in 2012.

In addition to the continued growth in North American natural gas supply, continued technological improvements have increased well efficiencies and reduced production costs while new industrial demand (including LNG export development) has grown more slowly. As a result, current medium and long term natural gas commodity price forecasts are lower than was predicted in 2012, as illustrated in the following figure.

[17] AECO/NIT (NOVA Inventory Transfer) is one of the largest natural gas trading hubs in North America, located in Alberta. AECO/NIT prices can be used as a high-level proxy for FEI's commodity supply portfolio costs.

Figure 10: AECO/NIT Historical and Forecast Natural Gas Prices



Source: GLJ Petroleum Consultants[18]

The continued lower level of natural gas prices in recent years has provided incentives and opportunities for the greater use of natural gas across North America. Demand is recovering in the industrial sector after being depressed from the 2008 recession. Additionally, new electricity load powered by natural gas and greater switching from existing coal-fired power plants to natural gas and combined cycle power plants contribute to the increased demand. Increasing exports of U.S. gas to Mexico, as well as the development of emerging markets such as liquefied natural gas (LNG) exports and natural gas for transportation (NGT) will add to demand over the long run.

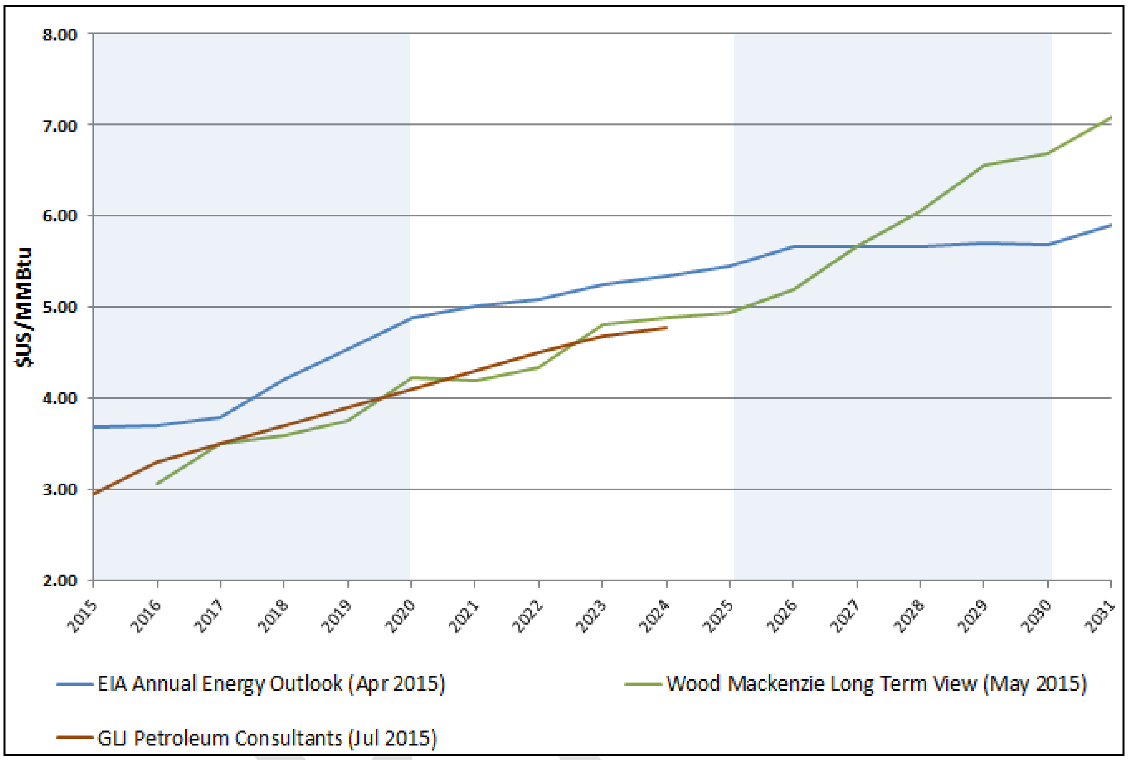
In terms of supply, the recent slowdown in the growth of gas production due to the low market price environment will also help to rebalance the market. Furthermore, with the recent drop in crude oil prices, producers are cutting back on oil production in the coming years, which will impact the associated gas that is produced with oil production. If oil and associated gas production is reduced, this could cut overall gas supply and lead to higher natural gas prices as the average cost to produce gas increases without contribution from liquids-rich associated gas. Figure 11 below compares long-term price forecasts from different information sources for Henry Hub[19] natural gas that would

[18] GLJ Petroleum Consultants Ltd. prepares commodity price and market forecasts after a comprehensive review of information available up to the reported quarter. Information sources include numerous government agencies, industry publications, oil refiners, and natural gas marketers. GLJ publishes these forecast reports every quarter and makes them available at http://www.gljpc.com/commodity-price-forecasts.

[19] Henry Hub is the benchmark gas trading hub for North America and is located in Louisiana.

reflect the expectations of the impact of long-term natural gas supply and demand fundamentals. The long term forecasts indicated that by 2020, gas prices could be within the $4.00-$5.00 US/MMBtu range. By 2025, analysts forecast that gas prices could be within the $5.00-$5.50 US/MMBtu range.

Figure 11: Long-Term Henry Hub Natural Gas Price Forecasts (nominal dollars)



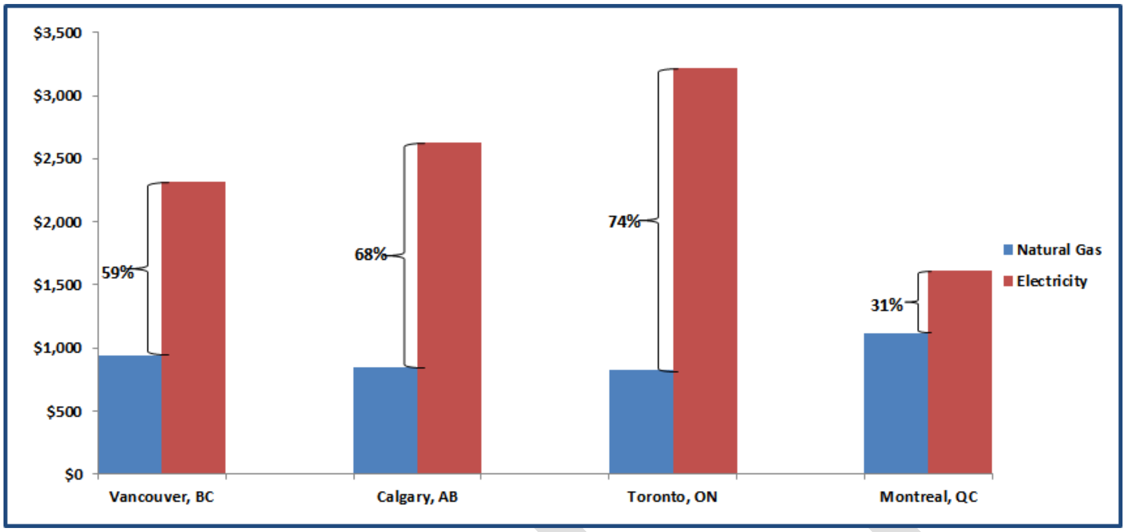
Given the combined factors of similar natural gas current market prices and a lower medium and long term commodity price expectation, FEI assesses the natural gas commodity price risk to be slightly lower compared to 2012.

Electricity Prices

The operating costs advantage of natural gas over electricity has historically been, and continues to be, lower in BC relative to some other jurisdictions, in particular Alberta and Ontario, because of BC Hydro's low electricity prices. Although BC Hydro electricity prices are forecasted to increase in the future, FEI will still be faced with the competitive challenges of maintaining and attracting customers that do not exist to the same extent in other provinces.

Figure 12 shows the extent to which residential electricity rates differ from province to province, with major cities represented. It also demonstrates how the magnitude of the cost difference between electricity and natural gas differs among these jurisdictions. Natural gas has the lowest operating cost advantage over electricity in major cities in British Columbia and Quebec.

Figure 12: Residential Operating Cost Differences between Natural Gas and Electricity



Assumptions:

- Electricity rates are as per the Hydro-Québec *Comparison of Electricity Prices in Major North American Cities* for rates in effect April 1, 2015
- Natural gas rates are effective as at June 1, 2015 with the exception of Toronto which is effective July 1, 2015
- The efficiency of gas equipment is assumed to be 90% relative to 100% for electricity to determine equivalent electricity.
- Estimated bills are calculated based on annual use rate of 90 GJs
- All bills are exclusive of applicable franchise fees and taxes (with the exception of BC Carbon Tax)
- 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

Even with recent BC Hydro rate increases, the price of electricity is still relatively low in BC compared to major cities in Alberta and Ontario, and is largely reflective of heritage or historical costs of supply. A large percentage of the costs making up BC Hydro's electricity rates are the low embedded costs of the province's hydro generation facilities.

Electricity rates in Quebec, which are also low compared to Alberta and Ontario, are also significantly influenced by relatively low embedded costs. In Alberta and Ontario, by contrast, electricity prices are based on market forces. In Alberta, electricity is generated mainly by the combustion of coal, which is generally more expensive than the historical cost hydro generation in British Columbia. Ontario has the most diverse electricity supply mix in Canada, with nuclear being the main source of electricity generation, followed by hydro and then natural gas. Despite the diversity of supply in Ontario, it has higher electricity costs than Quebec and BC.

The narrower operating cost advantage of natural gas over electricity in BC represents a greater challenge for FEI than exists for natural gas utilities in other jurisdictions like Alberta and Ontario. The relatively narrow operating cost advantage makes it more difficult to overcome obstacles to natural gas adoption such as greater price volatility and higher capital and installation costs, which are discussed next. As well, as the predominant generation source is hydro based, electricity has a more positive perception than natural gas.

5.2 Commodity Price Volatility

Natural gas prices are more volatile than electricity prices in BC principally due to the fact that natural gas is market-based, while electricity supply is primarily cost-based. Price volatility is an impediment to attracting and retaining natural gas customers because it can have a negative impact on natural gas rates and can taint consumers' view of using natural gas as a fuel. Greater price volatility can be perceived as leading unavoidably to ever higher prices and rates in the future.[21]

Despite the abundance of shale gas supply in North America, natural gas prices continue to remain volatile and can swing significantly in response to relatively short term market developments. For example, some regions may have limited pipeline or storage infrastructure to meet demand during peak times, which can lead to market price spikes and higher price volatility. BC is one of these regions where infrastructure is limited during high demand periods.

The issue of natural gas price volatility was discussed during the 2012 GCOC Stage 1 proceeding. In its decision, the Commission concluded that natural gas prices were projected to be relatively stable out to 2017 based on the forward price curve provided during the proceeding and that this indicated some level of stability over the next few years.[22] A single forward price curve represents prices that could be transacted on a particular date for delivery of gas at a certain point in the future. It does not reflect the potential variability in future prices based on changing market supply and demand factors or market events nor where future market prices will ultimately settle.

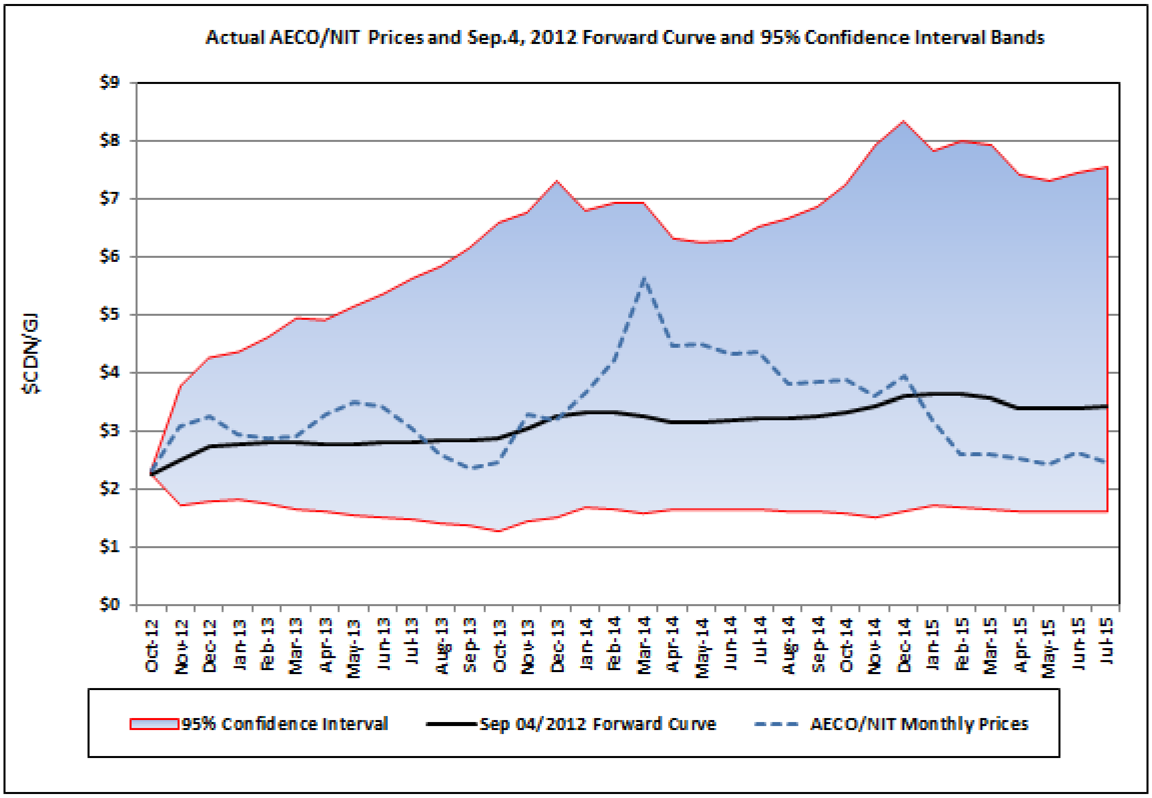
In fact, since the 2012 proceeding, natural gas prices have demonstrated a high degree of volatility, greater than had been expected by FEI and certainly much greater than concluded by the Commission in its decision. . The following figure shows the September 4, 2012 forward AECO/NIT prices and the 95% confidence level assessed at that time[23] compared to the actual AECO/NIT monthly prices. As illustrated, the actual monthly natural gas prices were not stable and experienced high volatility when compared to the September 4, 2012 forward price curve. Moreover, as discussed further below, daily spot prices experienced much more extreme volatility during this period.

[21] Sampson Research, 2012 FEU Residential End-Use Study - Section 4.2.7.

[22] FBCU 2012 Generic Cost of Capital Proceeding (Stage 1), Commission Decision May 10, 2013, page 32. The Commission's observation was based on the September 4, 2012 AECO/NIT forward price curve.

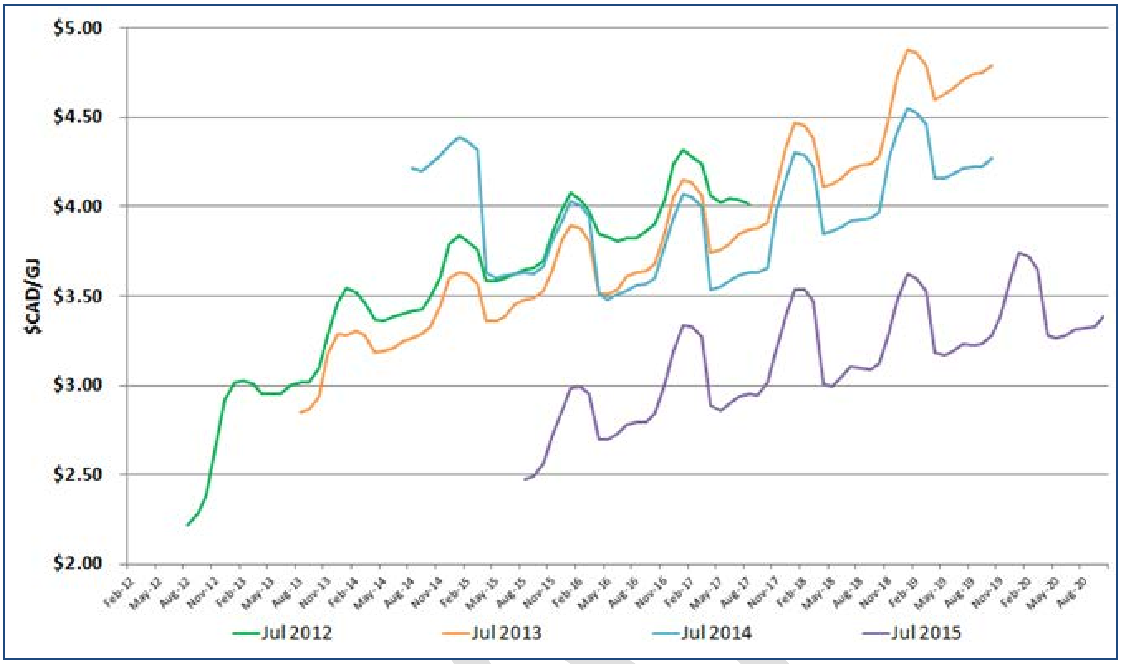
[23] The price probability range represents the market's view of the potential range for future gas price movements. This figure's potential range is based on a 95% confidence interval. It is derived using implied volatilities for future months. Implied volatility is the volatility of the price that is assumed by the market based on an option pricing model, such as Black-Scholes.

Figure 13: AECO/NIT Actual Prices vs. September 4, 2012 Forward Price Curve



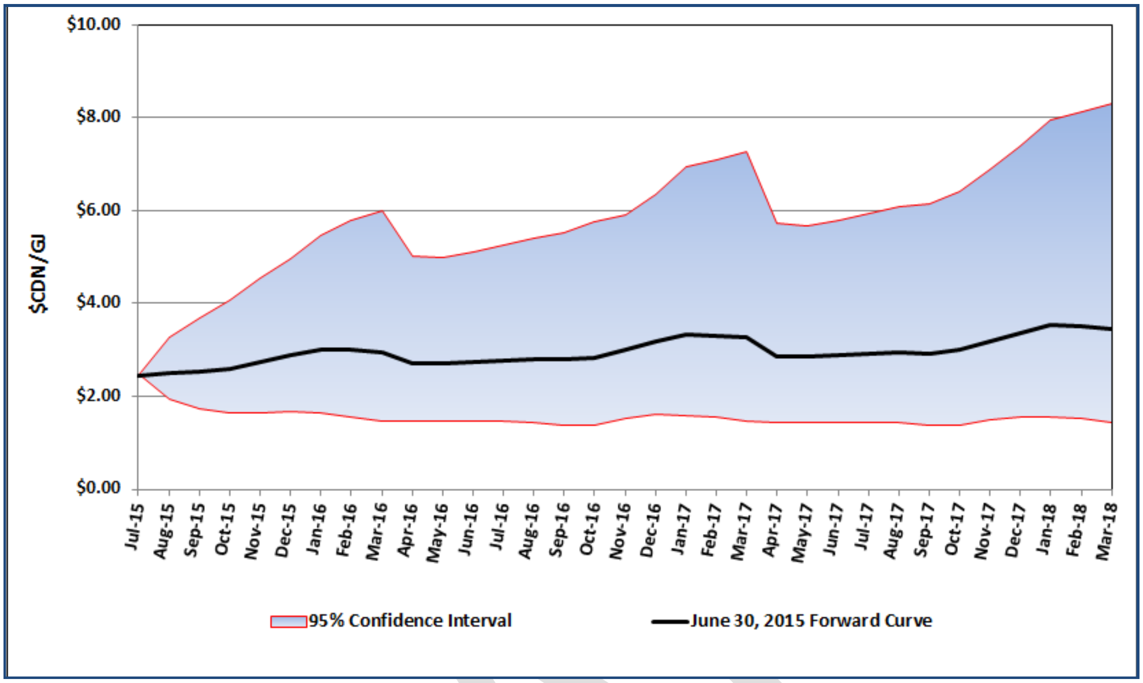
Since 2012, numerous developments in the natural gas market place have caused market prices to continue to swing significantly. In 2012, strong natural gas production, mainly from the development of shale gas, depressed industrial demand, and a warm 2011/12 winter contributed to high gas storage inventory levels and AECO/NIT prices dropped below $2.00/GJ by spring 2012. However, one of the hottest summers on record in 2012 increased gas demand for power generation throughout the summer storage injection season, which helped contract the large storage surplus before winter 2012/13. In winter 2013/14, North America experienced extremely cold weather and gas storage inventory levels dropped to their lowest levels in a decade coming out of that winter. Natural gas monthly prices increased to over $5.50/GJ in March 2014 (and went even higher on a daily pricing basis as shown in Figure 13) in response to concerns that storage levels would not recover before the next winter. However, the higher prices resulted in lower power generation load which combined with continued growth in gas production helped storage levels to recover before the winter 2014/15. With winter 2014/15 being closer to normal in terms of heating demand for most of North America and production growth continuing, storage levels have been close to historical average levels during 2015. This has resulted in market prices dropping during 2015, with AECO/NIT settling near $2.50/GJ by mid-2015. The following figure illustrates how the forward market price curves have shifted since 2012 in response to short term market developments and fluctuations in supply and demand. As the forward curve represents the price at which counterparties are willing to transact at any one time, the curves only represents the price at which FEI could potentially lock in part of its supply portfolio at that time and is not what a forecast of what its actual cost of gas will be over that period.

Figure 14: Changes in AECO/NIT Forward Price Curves



As in 2012, the 95% confidence range for recent forward market gas prices is still wide, reflecting the potential price volatility and continuing uncertainty in where market prices could ultimately settle in the future. This is illustrated in the following figure.

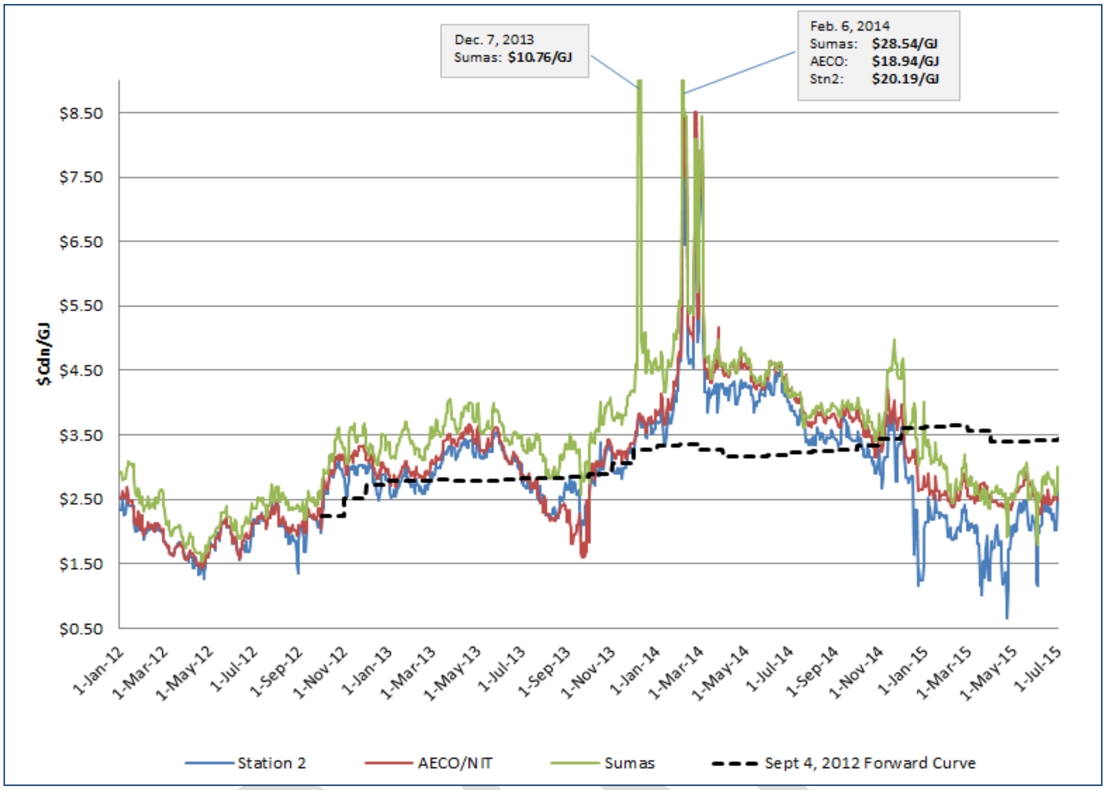
Figure 15: AECO/NIT June 30, 2015 Forward Price Curve and 95% Confidence Interval Bands



Daily gas prices have been even more volatile than monthly and forward market prices.The following figure shows the actual AECO/NIT, Station 2 and Sumas[24]daily prices since 2012 compared to the September 4, 2012 forward curve. The actual daily spot prices have exceeded the price levels from the September 4, 2012 forward curve for most of the time since 2012 and have dropped below that forward curve in 2015.

[24] Sumas is the trading hub located on the BC-Washington border at Huntingdon. It is the main trading hub for BC gas supply moving south to US markets.

Figure 16: Actual Regional Daily Prices



As illustrated, regional daily gas prices have fluctuated from lows below $1.50/GJ in April 2012 to highs of over $18.00/GJ in February 2014, before falling back to the $2.50/GJ level and below again by June 2015.

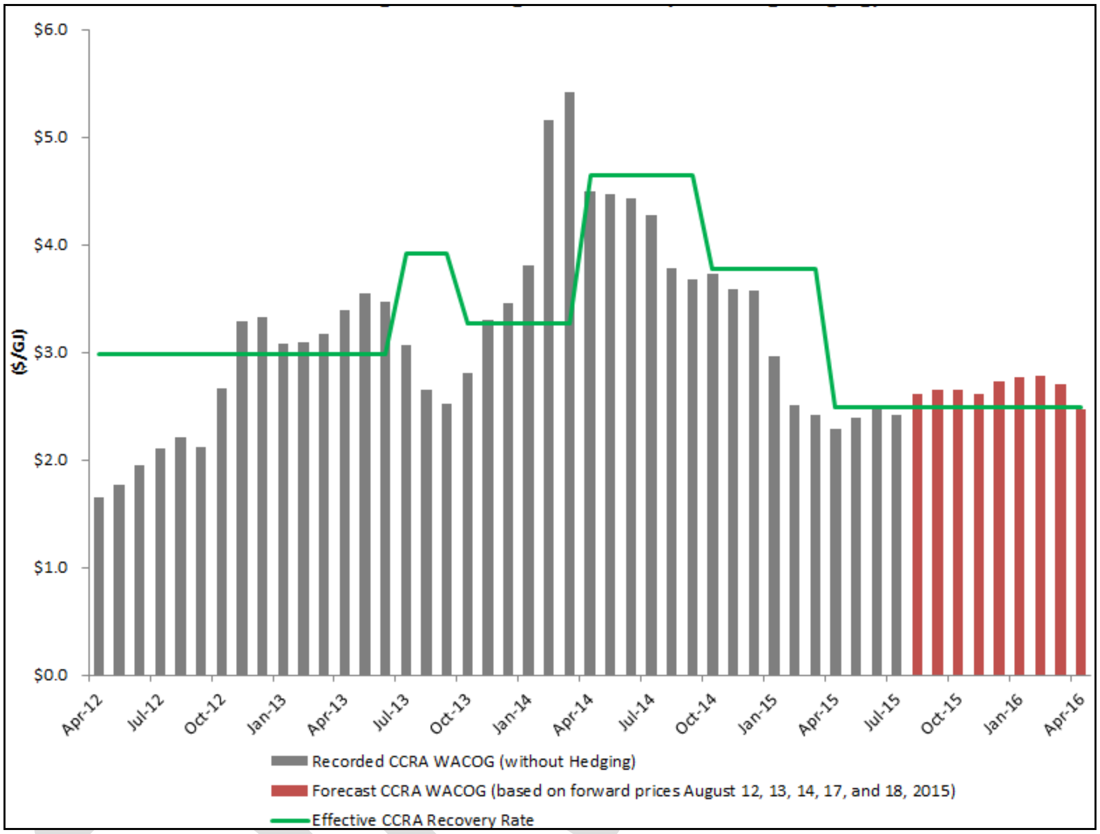
Prices at the Sumas market hub often disconnect from other regional prices, such as those at the Station 2 and AECO/NIT market hubs, in times of cold weather and high regional demand. This occurs because winter demand reaches or exceeds the current maximum pipeline capacity that is available for the delivery of gas supply to Sumas. In December 2013, Sumas prices disconnected from AECO/NIT and Station 2 prices and spiked to over $10.00/GJ during a cold spell in the Pacific Northwest (PNW) region. Moreover, during a cold spell in February 2014, unlike in December 2013 where only the Sumas price was disconnected, the AECO/NIT and Station 2 prices also spiked due to high gas production freeze-offs[25] and low gas storage inventory levels in Alberta. AECO/NIT and Station 2 prices spiked and settled close to $20.00/GJ and Sumas gas prices settled at over $25.00/GJ. These prices represented the highest market prices <u>ever</u> realized at the AECO/NIT or Station 2 market hub[26].

[25] Natural gas wellhead freeze-offs happen when outside temperatures drop below freezing in producing fields. If the wellhead is not protected then water and other liquids in the gas can freeze and block the flow of gas.

[26] Based on next-day daily settled prices.

This market price volatility is reflected in FEI's commodity portfolio weighted average cost of gas (WACOG). These are the costs that represent the actual cost of gas purchases and are ultimately recovered from customers through commodity rates. The following figure illustrates the Commodity Cost Reconciliation Account (CCRA) WACOG and FEI's actual commodity rates over the past three years.

Figure 17: WACOG vs Commodity Rate (excluding hedging)



As the figure above illustrates, similar to the regional gas prices, FEI's WACOG and commodity rate have fluctuated significantly throughout the past three years. FEI commodity rate has moved from near $3/GJ in 2012 up to almost $5/GJ in 2014 and then back down again to near $2.50/GJ in 2015.

Regional Infrastructure

This regional market price volatility is expected to continue in the future. Regional infrastructure additions can help mitigate some of the regional price disconnection risk; however, these additions require a long time to plan, to secure shipper commitments, to receive regulatory approval, and to construct. The Southern Crossing Pipeline, Mt. Hayes LNG, and Mist and Jackson Prairie storage facilities expansions are examples of regional infrastructure that were approved and subsequently constructed to meet growing regional demand that helped to reduce some of the regional constraints. However, further infrastructure may be needed to meet the pace of demand growth in the PNW region if new industrial base load is added.

Although regional residential and commercial market demand growth is expected to be relatively flat, significant new regional demand could come from new projects relating to LNG exports, natural gas power generating plants replacing coal-fired plants and industrial plants. These new projects will require gas supply from Northern BC, Alberta, the US Rockies, using Spectra's T-South pipeline system, NGTL/Foothills/GTN and/or the Northwest Pipeline System to move supply to their facilities. However, this incremental demand requires greater regional pipeline capacity than is currently available. FEI's industrial customers, as well as those in the US PNW, responsible for arranging their own gas supply risk being left without access to sufficient capacity to meet all of their demand because they may not be able to meet the requirements needed to underwrite the development of new transportation capacity. The Northwest Gas Association (NWGA) publishes an annual energy outlook report every year providing an overview and projection for natural gas supply, demand, and capacity in the Pacific Northwest region for the upcoming ten years. The following figure illustrates NWGA's latest projection of the PNW's peak day resource/demand balance with and without potential accelerated demand if some of the proposed regional projects proceed.

Figure 18: PNW Accelerated Demand Peak Day Resource/Demand Balance[27]

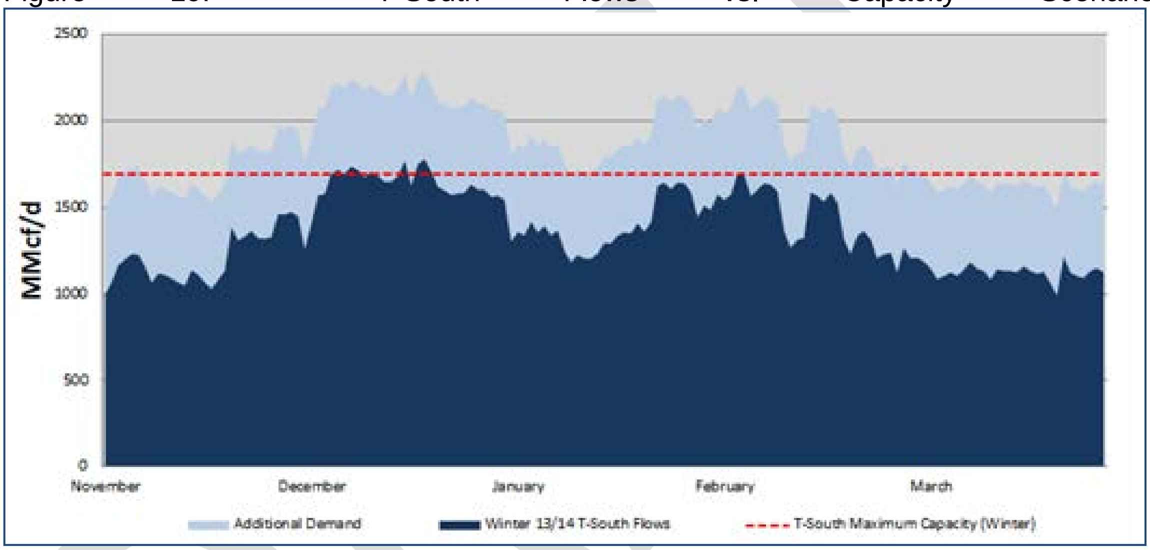
In its accelerated demand peak day scenario, NWGA estimated that there could be an additional 100 MMcf/d of natural gas demand in the PNW region by the end of 2024 due to expanded power generation demand, mainly from coal plant retirements. In addition, general industrial load, including smaller LNG projects, could increase natural gas

[27] Northwest Gas Association – 2015 Gas Outlook

demand by another 435 MMcf/d by the end of 2024. Furthermore, an additional 960 MMcf/d of natural gas demand is being proposed to come online from three recently proposed methanol plants in Washington and Oregon along the I5 corridor. Depending on how much incremental regional capacity becomes available over time, some current demand that has been depending on interruptible capacity may be left without capacity. The consequence of this outcome would likely result in higher regional spot prices and more price volatility or unserved demand, especially during high demand periods.

The potential for new regional baseload industrial load will result in greater competition for existing pipeline capacity on a year round basis. The following figure shows a scenario of what winter 2013/14 T-South flows would look like with an additional 500 MMcf/d of gas demand compared to current pipeline capacity levels and demonstrates that new regional pipeline capacity will be required to support many of these projects.

Figure 19: T-South Flows vs. Capacity Scenario



While expanding the Spectra T-South system is an option, along with other pipeline solutions, these require long-term shipper commitments and several years to complete. And while these proposed projects can also take years to complete, the timing of the completion of such projects does not always align with the required infrastructure, leading to the potential for supply/demand mismatches and price volatility.

Price Risk Management

FEI's current price risk management strategies help to mitigate the impact of regional market price disconnections and regional market price volatility on customer rates. These include the use of commodity rate setting and deferral account mechanisms, the use of natural gas storage and gas supply purchasing strategies that provide supply hub and market pricing diversity. However, FEI continues to operate with limited price risk mitigation strategies that directly impact underlining market prices, such as hedging activities, and therefore FEI's supply portfolio continues to be exposed to market price fluctuations.

In its 2012 GCOC Decision, the Commission disagreed with FEI's assertion that it had fewer tools to manage price volatility and that it had expected FEI to consider alternatives for managing market price risk. During the past few years FEI has taken a number of actions in this regard which include the following:

- Research regarding customers' preferences in terms of rate and bill changes and alternative optional commodity rate offerings;
- Removing Huntingdon supply and Sumas price risk from the commodity and midstream supply portfolios;
- Entering into long-term gas supply contracts with BC producers which promote commitment to providing supply to the Station 2 market hub;
- Entering into long-term natural gas storage arrangements;
- Securing Station 2 gas supply with a fixed discount to AECO/NIT pricing;
- Independent consultant review of FEI's price risk management tools and strategies and recommendations for enhancement;
- Submission of the 2014 Price Risk Management Review Report (Review Report) which included a review of FEI's current and available price risk management strategies;
- Discussions with Commission staff regarding the Review Report and approach for stakeholder consultation;
- Engaging stakeholders in workshop discussions to help determine FEI price risk management objectives and potential strategies going forward.

FEI has just completed a series of workshop discussions with stakeholders and is currently preparing a summary report on findings and recommendations from the stakeholder consultation process. Although stakeholders views were varied, FEI is hopeful that this process will lead to better understanding of the market price risk that customers are exposed to, and also to the tools that FEI has or could have to manage market price volatility on behalf of customers.

With regional market price volatility continuing, regional infrastructure becoming more constrained in the future, and limited ability to use additional price risk management tools to manage the underlying gas price volatility from market fluctuations, FEI assesses the risk associated with market price volatility to be higher than 2012 and significantly higher than the Commission's expectations in 2012.

5.3 Upfront and Installation Costs

Sections 5.1 provided an overview of natural gas price competitiveness on the basis of operating costs. In this section, the price competitiveness will be analyzed considering the upfront capital cost differences between natural gas and electricity end-use applications (space and water heating).

This analysis is relevant to the challenges faced by FEI in attracting new customers. Builders and developers are the primary decision makers as to what energy source and equipment are used in new construction. As builders and developers do not pay the operating costs, they tend to be more influenced by capital costs alone. A builder or developer also strives to maximize the useable square footage available from the development to maximize their return on investment. Capital cost savings and the ability to sell more useable living space incents developers and builders to install electricity equipment over natural gas equipment in new developments for certain housing segments. The following excerpt from a 2014 report by IHS CERA[28] confirms FEI's standpoint:

> *"Finally, builders and landlords generally prefer to install appliances with lower up front capital costs, even though they may have higher operating costs, as builders do not generally have to pay operating costs. For this reason, the builder/landlord preference usually favors the electric appliance over the gas one unless customers request gas"*[29].

Table 6 below provides as an example the upfront installation (capital) cost difference associated with natural gas versus electricity for a space heating furnace and hot water tank for new construction. In this example, assumptions were based on a single family dwelling (Medium Size, 3000 square feet). When considering smaller multi-family dwellings ("MFD"), such as townhouses and apartment units, the higher capital cost of natural gas further decreases cost competitiveness of natural gas in space and water heating applications.

Table 6: Upfront and Installation Costs for Space and Water Heating

	Space Heating	Water Heating
Capital costs for natural gas	$9,000	$2,000
Capital costs for electric	$4,435	$1,000
Difference in capital costs	**$4,565**	**$1,000**

Notes:

- Assumptions based on the new construction of a home in the Lower Mainland (Medium Size Dwelling at 3000 square feet).

Compared to 2012, the difference in upfront capital costs between natural gas and electricity for space heating and water heating purposes has not materially changed. Therefore FEI has assessed that the risk associated with the upfront and installation costs has remained unchanged.

[28] IHS CERA is a U.S. based consulting firm that specializes in advising governments and private companies on energy markets, geopolitics, industry trends, and strategy. CERA has research and consulting staff across the globe and covers the oil, gas, power, and coal markets worldwide.

[29] http://www.fuelingthefuture.org/assets/content/AGF-Fueling-the-Future-Study.pdf.

The IHS CERA report also recognizes that even when the operating and upfront capital costs are paid by the same end-user and not the developer and builder, the relatively long pay-back period may be a deterrent to customers:

> *"The natural gas advantage is realized over time as lower fuel costs gradually overcome the higher initial costs, but payback periods may be longer than consumers are willing to accept."*

This statement can be analysed by combining the effects of upfront and installation costs with the operating costs. As demonstrated in Table 7 the difference in upfront capital costs between gas and electric means that over the life of the appliance the operating cost advantage between natural gas and electricity would have to be at least $13.84/GJ for space heating and $5.25/GJ for water heating for the installation of the natural gas rather the electric equipment to be economic for the consumer.

The difference in unit capital costs between natural gas and electricity is larger than what was reflected in the data FEI presented in 2012, particularly for space heating. The increase is explained by lower energy consumption assumption for space heating[30].

Table 7: Difference in Costs for Space and Water Heating over Measurable Life

	Space Heating	Water Heating
Difference in capital costs	**$4,565**	**$1,000**
Annual payments for recovery of capital costs	$422	$116
Maintenance costs per year	$100.00	$0.00
Total costs per year to pay off difference in capital cost	**$522**	**$116**
Energy consumption (GJ)	38	22
Difference in costs between natural gas and electricity over measureable life ($/GJ)	**$13.84**	**$5.25**

Notes:

- Assumptions based on the new construction of a home in the Lower Mainland (Medium Size Dwelling at approximately 3,000 square feet), interest rate of 6% and the measurable life of 18 years for a natural gas space heating furnace and 13 years for hot water tank. The annual payments to recover the difference in upfront capital costs is calculated based on the present value of an annuity formula where PV of an annuity = annuity * [(1-(1+r)^-n)/r] (r is interest rate and n is the measurable life of the equipment).

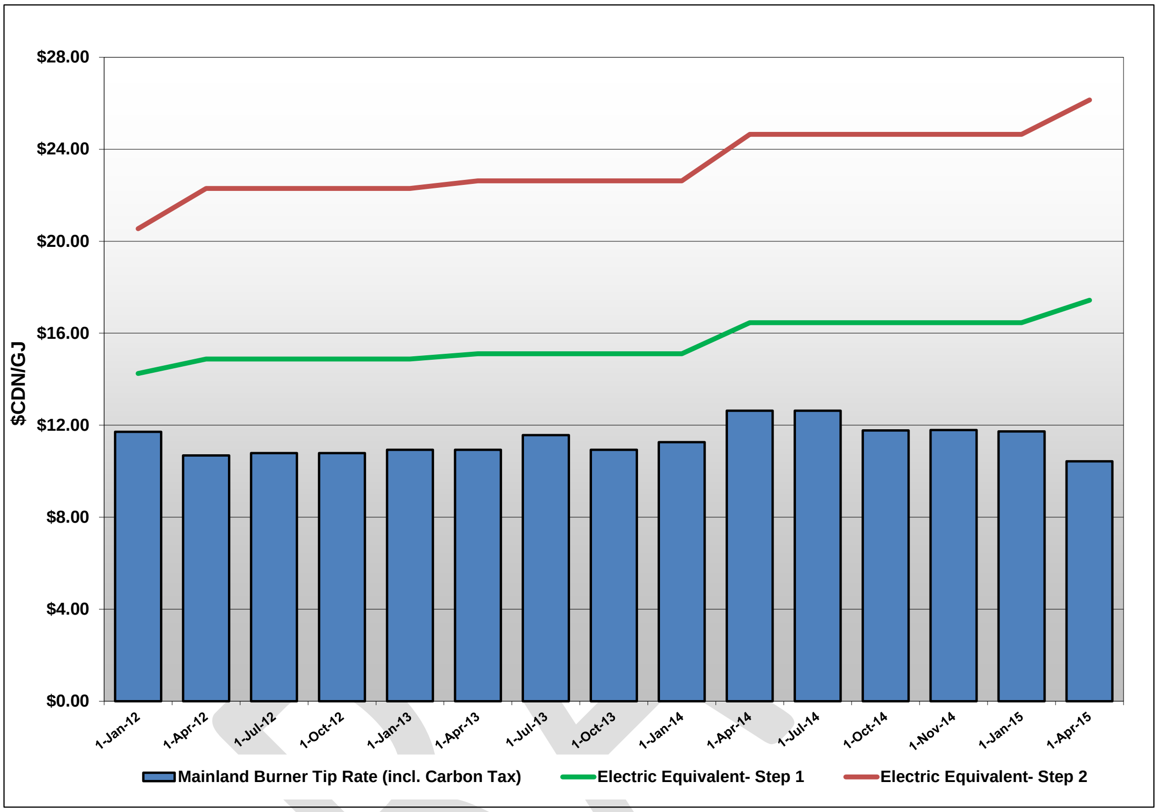
Figures 20 and 21 present a historical view of FEI's competitiveness with space heating.[31] As shown in Figure 20 below, FEI's burner tip rate absent the capital costs

[30] The consumption assumption is based on a 2014 BC building code compliant home.

[31] FEI burner tip rate presented in the figure includes the commodity charge, storage and transport charge, fixed basic and delivery charges, and the Carbon Tax to provide a comparison against the electric equivalent, (based on an average annual use rate of 90 GJ per year). The Step 1 and Step 2 BC Hydro RIB rate electric equivalents have been adjusted using a 75% efficiency to represent the average efficiency level of all existing space heating customers in Figure 19. Similarly, the Step 1 and Step 2 electric equivalents have been adjusted using a 92% efficiency to represent the average efficiency level of a new gas fired furnace in Figure 20. It is important to note that the rate the BC Hydro customers ultimately pay is dependent on their actual consumptions (Step 1 and Step 2). This can impact the rate comparisons of natural gas against electricity depending on the customer's consumption levels for electricity. For example, water heating load may be better compared to Step 1 electricity

(indicative of a customer that already has appliances installed) have been below the average rate and Step 1 electric equivalents since 2012.

Figure 20: FEI Mainland Service Territory Existing Space Heating Burner Tip Rate vs. Electric Equivalents



The inclusion of the upfront capital costs associated with the installation of a gas furnace (indicative of a customer that directly incurs the upfront capital costs of installing gas over electric appliances) reduces FEI's competitive position against the electric equivalents. From January 2012 to April 2015, FEI's burner tip rate plus the capital cost put the total cost per GJ above the Step 1 electric equivalent. Higher total costs of installing gas over electric indicate to the consumer that electricity is the more economical option.

rates because it generally has a flat yearly profile versus space heating which would have a winter profile (Step 2).

Figure 21: FEI Mainland Service Territory New Space Heating Burner Tip Rate and Capital Cost vs. Electric Equivalents

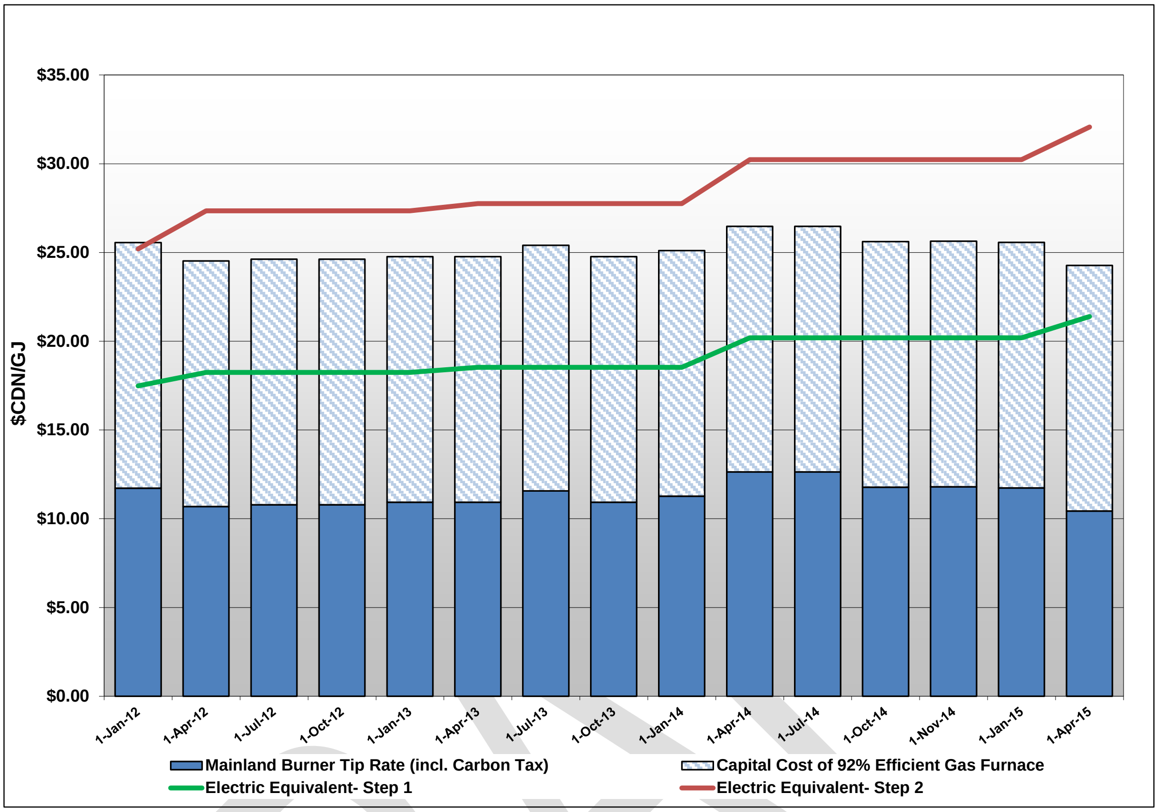
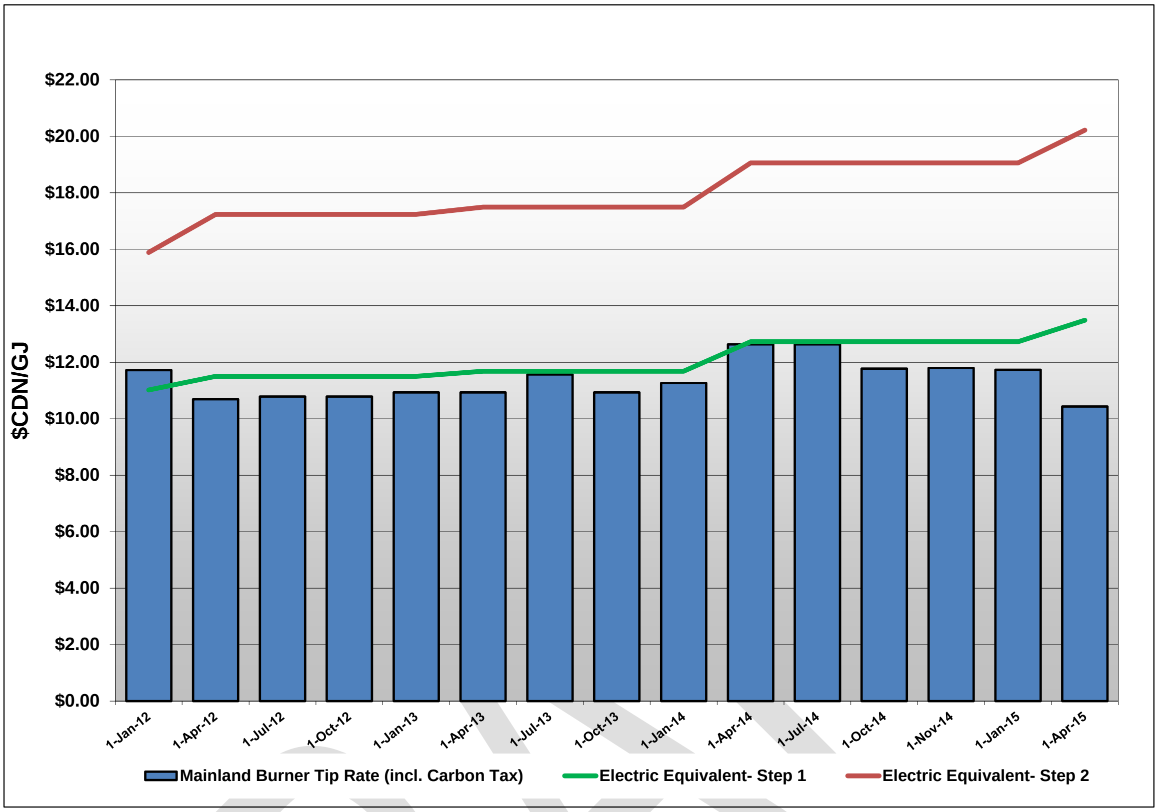


Figure 22 and Figure 23 below present a historical view of FEI's competitiveness in the water heating market. The FEI burner tip rate includes the commodity charge, storage and transport charge, fixed basic and delivery charges, and the Carbon Tax to provide a comparison against the electric equivalent. The Step 1 and Step 2 electric equivalents have been adjusted using a 58 percent efficiency to represent the efficiency level of a current installed gas fired hot water heater for Figure 22 and 62 percent for Figure 23 to represent the efficiency level of a newly installed gas fired hot water heater.

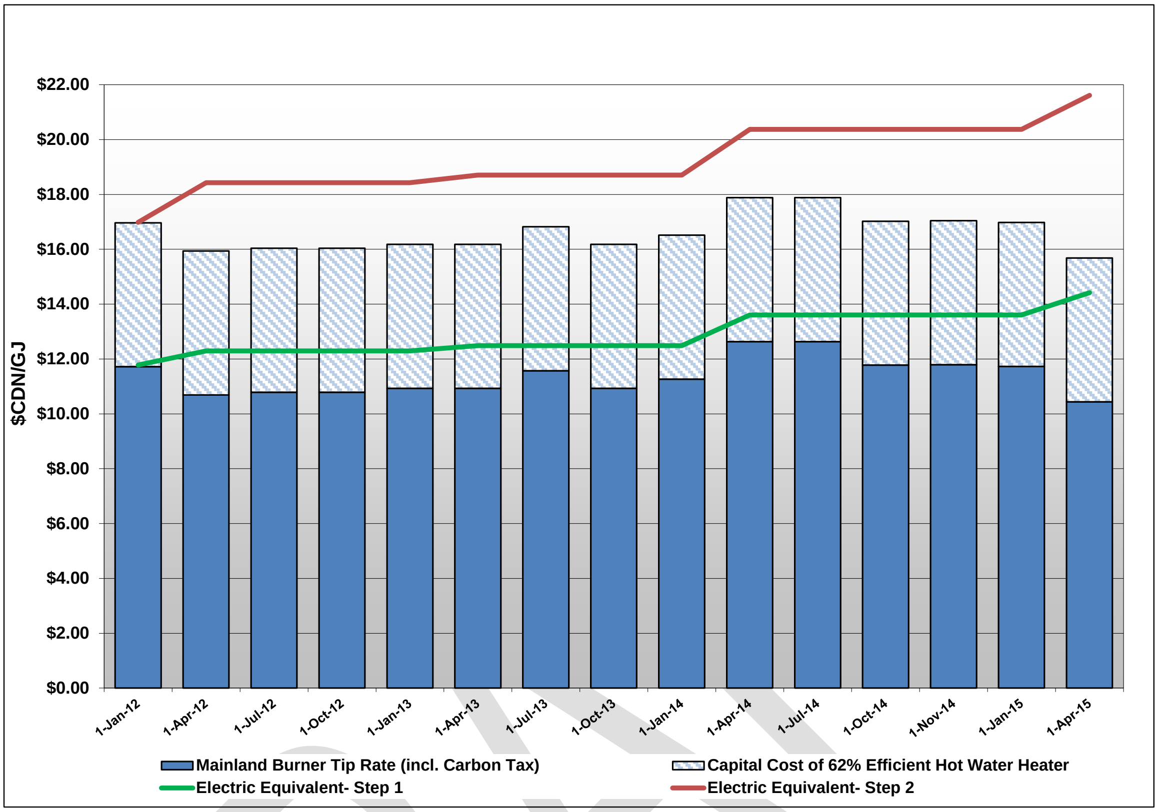
Figure 22 shows the comparison without capital costs, which is indicative of a customer that has existing water heating equipment and therefore the energy equipment is a sunk cost.

Figure 22: FEI Mainland Service Territory Existing Water Heating Burner Tip Rate and Capital Cost vs. Electric Equivalents



The inclusion of the upfront capital costs associated with the installation of a natural gas hot water heater reduces FEI's competitive position against the electric equivalents. From January 2012 to April 2015, FEI's burner tip rate plus the capital cost put the total cost per GJ above the Step 1 electric equivalent.

Figure 23: FEI Mainland Service Territory New Water Heating Burner: Tip Rate and Capital Cost vs. Electric Equivalents



Until January 1st, 2018 when the phase-in period is completed, delivery rates for the Vancouver Island and Whistler service territories remain higher than mainland delivery rates and therefore the competitiveness of natural gas compared to electricity for these service areas continue to be lower than FEI.

In general, with recent increases in electricity prices the current price competitiveness of natural gas has marginally improved, other things being equal. However, as discussed in the market shift risk and political risk sections, the improved price competitiveness of natural gas continues to be muted by non-price factors.

6. MARKET SHIFTS RISK

The choice of energy, and how it is consumed and produced, is influenced by the introduction of new technology and energy forms, changing customer perceptions of energy, and the types of homes being built. Market shifts in these areas continue to pose challenges to FEI's ability to attract and retain customers, and maintain market share and throughput levels.

The available data since the 2012 GCOC proceeding has reaffirmed that the declining trend in throughput level, particularly in the residential sector, is mainly due to two continuing trends: (a) declining annual use trends from existing and new customers mainly caused by the improvements in energy efficiency and conservation as well as smaller average dwelling size; and (b), the weak capture rate in the new construction market in the growing multi-family sector.

6.1 New Technology and Energy Forms

FEI's assessment is that new technology and energy forms present similar risks for FEI Amalco as they had presented for the benchmark utility FEI in the GCOC proceeding.

In 2012, FEI identified that the adoption of different energy forms in combination with newer technologies represents a challenge to FEI's core business of providing natural gas for space and water heating. FEI addressed the fact that numerous new end-use technologies have entered the energy services marketplace in recent years and will likely continue to do so in the foreseeable future. Developers are responding to their customers' desires for efficiency and innovation by in some cases installing newer technology that, while similarly or higher priced than gas equipment, suggests to the buyer that the homes are more advanced and efficient. These houses then command a higher margin for the developer and natural gas is squeezed out.

In addition to advancements on both natural gas and electricity-based heating equipment, advancements in renewable thermal energy solutions have emerged to take a small but growing slice of the market. Examples of renewable thermal solutions include air and ground source heat pumps for single family residences; and district energy systems that can employ one or more renewable energy systems such as waste heat from industrial processes, geo-exchange technologies, or biomass solutions often in combination with natural gas-fired heating solutions. FEI continues to assess how these renewable thermal solutions are impacting natural gas demand and how they are changing the way customers are using natural gas.

The application of existing alternative technologies and the introduction and adoption of new technologies and energy forms has implications for FEI.

- First, renewable thermal energy solutions such as geo-exchange systems, waste heat recovery systems and solar thermal systems can displace both existing and future expected demand for natural gas. While FEI does not offer these services to its customers, the potential for other third party service providers to do so creates a risk to FEI's annual demand profile.

- Second, the changing landscape of technologies influences codes and regulations and building design and controls, which can have an impact on energy use.

In recent years, non-government organizations such as the Community Energy Association, Pembina and Quality Urban Energy Systems of Tomorrow (Quest) are acting as catalysts to spur interest in district energy systems. A Quest progress report published in August of 2013 provided a brief overview of the integrated community energy solutions (ICES) in BC.[32] According to this progress report, more than thirty district (multiple customers) and discrete heating systems were operational in 2013 with more than ten projects in advanced planning, design or approval stages with many more being at the feasibility study stage (for a detailed list of projects and technologies used please refer to the Quest's progress report).

Government is also a factor in the trend towards alternative energy forms. For example, BC's Government infrastructure planning grant program offers grants up to $10,000 to support local government in projects related to the development of sustainable community infrastructure. Along with supporting the development of new technologies and energy forms in residential and commercial sectors, the BC Government has also strived to promote the use of alternative fuels and new technologies in the industrial sector. For instance, the 2015 BC provincial budget includes a transitional incentive plan of $22 million paid over a three year period, to encourage the BC Cement industry to adopt cleaner fuels and further lower emission intensities. The lower carbon and zero-carbon alternatives the industry is exploring range from waste wood and un-reusable residuals from recycling to bio coal[33]. According to the Canadian Cement Association, the major plants operated by the two major cement manufacturers in BC would use the money to help subsidize the development of alternative fuel sources[34].

Examples of requirements adopted by local governments for developers to consider alternative energy systems are addressed later in the political risk section of this Appendix.

Since 2012, a number of regulatory exemptions have been granted to companies that provide new technology and renewable energy services. These exemptions further facilitate the development of these industries and increase their competitiveness against regulated utilities. One such an exemption is the recent Order in Council No.23 that exempts the "*class of cases where a person, not otherwise a public utility, offers lease agreements or energy supply contracts providing lessees or buyers with solar or wind energy systems or facilities, that could otherwise be purchased on the open market, provided that the value of the installed system including equipment, labour and permits, does not exceed $500,000*"[35]. This will allow entities such as Vancouver Renewable Energy Cooperative (VREC) to be exempt from the Commission's oversight.

6.2 Perception of Energy

FEI's assessment is that perception of energy presents similar risks for FEI Amalco as they had presented for the benchmark utility FEI in the GCOC proceeding.

[32] Quest BC; August 2013, Integrated Community Energy Solutions Progress Report

[33] http://www.vancouversun.com/business/resources/Cement+industry+fires+search+alternative+fuels+reduce/10881358/story.html

[34] Coal and natural gas are the main substitute fossil fuels that are used in cement production and an increase in the use of alternative fuels could negatively impact FEI's industrial throughput.

[35] http://www.bcuc.com/Documents/SpecialDirections/2015/01-16-2015_OIC23-VRECExemptionApproval.pdf.

Historically, customer energy choices tended to be driven by market factors such as energy price, accessibility, ease of use, reliability, and availability. FEI's customers are now also influenced by a desire to use energy efficiently and to adopt lower carbon and renewable energy sources. This creates challenges for natural gas utilities generally in retaining and attracting heating load, despite the lower natural gas commodity prices currently being experienced. FEI has conducted a number of surveys and studies since the 2012 GCOC Application. Figure 24 summarizes key findings from recent FEI surveys that were undertaken to understand how consumers perceive their home energy options.

Figure 24: Summary of Customer Perception Research

Alternative Energy Surveys
2009, 2010 and 2012

- Assessed the public's willingness to adopt alternative energy technology, and associated with this, their willingness to pay for them.
- Indicated that while BC residents' awareness and knowledge of alternative energy sources remained steady in 2012 when compared to 2010, they continue to strongly favour incorporating alternative energy sources into new homes. The willingness of BC's residential market to incorporate alternative energy sources has softened in recent years from 69% (2009) to 62% (2013). Barriers identified include: (a) the high capital costs of adoption; and (b) builders and developers cite a lack of voiced demand.

Gas is Good Campaign Assessment
2013 and 2014

- Measured the public's preference for natural gas appliances and their likelihood to consider natural gas appliances in their home buying decision. The study coincided with the Gas is Good advertising campaign which was focused on people looking to buy homes.
- The study showed that over a 12 month period, the percentage of residents receptive to natural gas doubled from 16% to 34%. Over the same period the percentage of respondents who mentioned heating systems as an important factor when buying a new home increased from 3% vs. 10%.

Energy Source Usage Preferences Study
2011 and 2013

- Tracked and measured preferences for future energy sources and attitudes impacting future energy sources.
- A sizeable number of households continue to be unhappy with the energy source they currently use. Furthermore, results show a decided preference for geothermal heat pumps for space heating (50%) compared to a natural gas furnace (43%). In terms of water heating, respondants preferred a tankless water heater (47%). A storage water heater was the second most favorable option (31%). Respondants indicate their energy source preferences for space and water heating are primarily influenced by perceived reliability of the energy source, followed by perceived safety of the energy source.

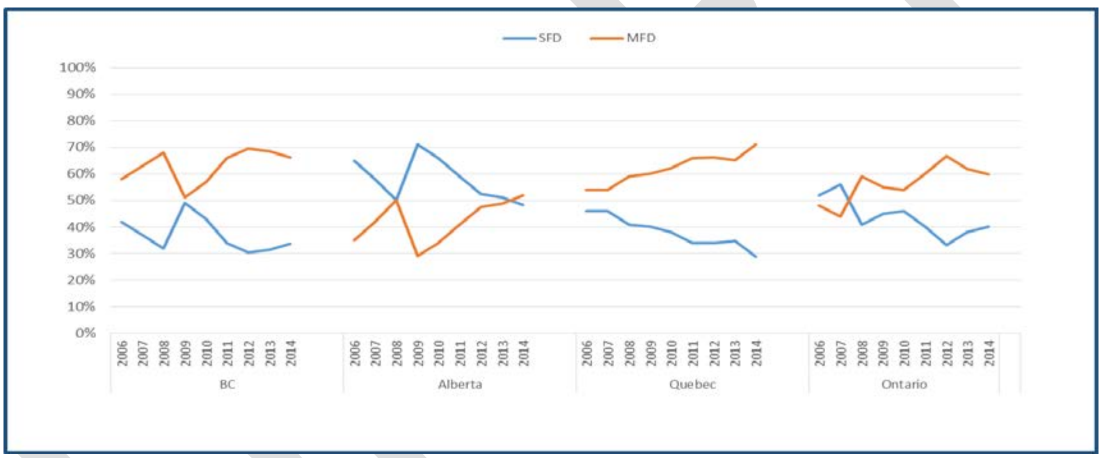
These surveys indicate a gap between developers' preferences (currently used systems in place) and end-use customers' preferences. For instance, gas ranges and cooktops are preferred for cooking even though electrical ovens are more common. The differences between preferred and currently used systems can stem from many barriers ranging from financial disincentives to a lack of strong desire for change.

6.3 Housing Types

The market shift in new home development (from single family to multi-family) is adversely impacting FEI's natural gas use and capture rates in a manner similar to what was taking place in 2012. Considering the current lower capture rates in Vancouver Island service area, amalgamation has had a slightly negative impact on FEI Amalco's overall capture rate. For instance, in the single family dwelling category, the amalgamated FEI's capture rate is around 77 percent while FEVI's and non-amalgamated FEI's capture rates were 52 and 84 per cent respectively. Nevertheless, the amalgamation will bring about large rate decreases on Vancouver Island over the three year phase-in period and may well improve the capture rates (in other words, historical capture rates may not be indicative of capture rates going forward).

As shown in Figure 25, there is still a significant gap between the single-family and multi-family housing starts with close to 70 percent of all housing starts classified as multi-family dwelling.

Figure 25: Single Dwelling vs. Multi-Family Housing Starts in Selected Canadian Provinces



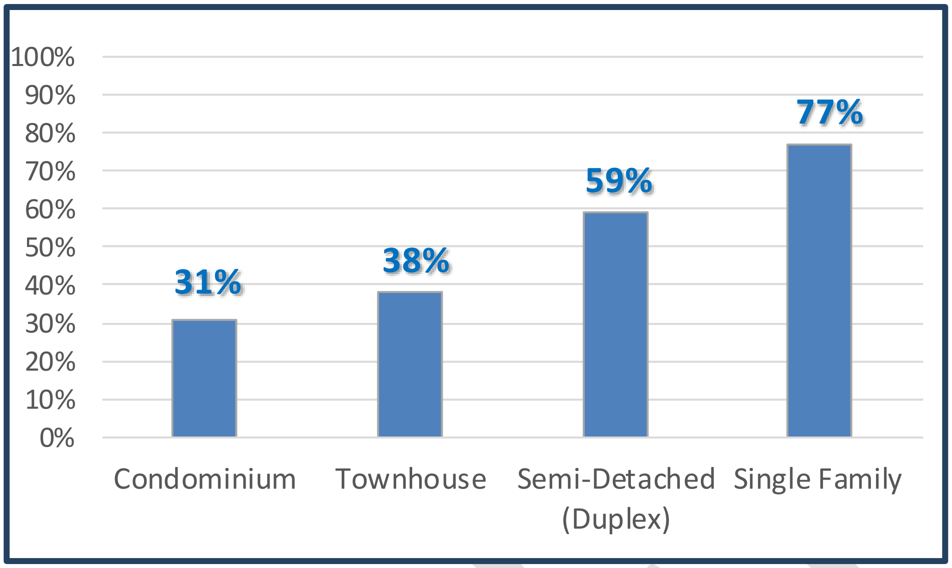
Source: CMHC 2015 Housing Market Outlook, Canada Highlights Edition

There are two key implications for FEI of the mix favouring multi-family dwellings.

First, in line with previous studies, the 2012 Residential End Use Study (REUS) survey shows that, on average, annual consumption for natural gas is greater in single-family dwellings than in multi-dwellings. In order to maintain existing throughput levels in an environment where single-family dwelling housing starts are trending lower, natural gas utilities will need to capture more multi-family dwellings to offset the reduced levels of system throughput related to improvements in energy efficiency and technology.

Second, natural gas has a low penetration rate in multi-family dwellings. Figure 26 shows amalgamated FEI's capture rates by housing types for 2013.

Figure 26: Combined FEI/FEVI/FEW Capture Rates by Housing Type (2013 data)



The lower capture rate for multi-family dwellings is primarily driven by the unfavorable economics of installing a natural gas application as compared to an electric equivalent.[36] This is especially true for developments where the unit cost plays a primary role in the purchasing decision. In general, developers have a strong incentive to install electric baseboard heating for multi-family dwellings, as opposed to natural gas, given the comparatively high capital costs of natural gas heating appliances, ducting and overall installation costs. Natural gas space heating equipment also occupies valuable living space within a multi-family unit which could otherwise contribute towards a developer's return.

Another significant factor threatening FEI's capture rates (in both residential and commercial sectors) is associated with potential mandatory connection of entire neighborhoods with high population density to district energy systems. For instance, the City of Vancouver has endorsed an application by Creative Energy for a district energy system in North East False Creek and Chinatown, with plans to expand district energy service elsewhere in the City. The City has entered into an agreement with Creative Energy, in which the City commits to passing a mandatory connection bylaw. The bylaw would compel new and renovated buildings in designated neighbourhoods to connect to the Creative Energy district energy system, and thus prevent potential energy consumers in designated areas from choosing natural gas for space and water heating. In its application Creative Energy described that the City of Vancouver was intending to follow this model for the Cambie and Broadway corridors, representing a current 10+PJ of FEI load.

36 American Gas Association. Squeezing Every BTU: Natural Gas Direct Use Opportunities and Challenges. page 36.

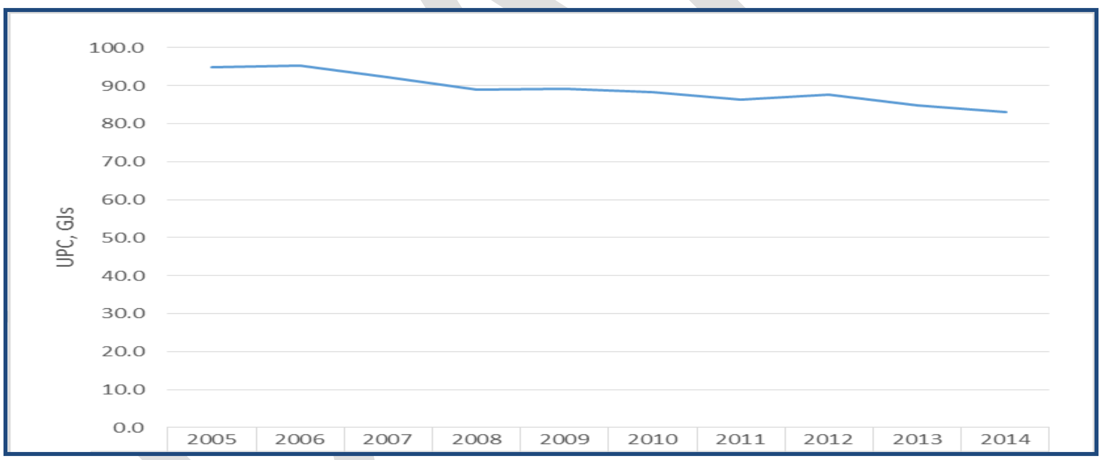
Over the longer term it is expected that electricity will continue to enjoy a greater market share in the multi-family dwelling sector than natural gas.[37]

6.4 Changes in Energy Use

FEI continues to face declining annual use rates from its existing customers, primarily in the residential sector. This has a direct impact on throughput levels. The residential Use per customer (UPC) has been historically higher on the Mainland in comparison to the Vancouver Island service area. As such, blending in the lower UPC accounts from Vancouver Island means that the amalgamated FEI UPC is lower than for the pre-amalgamated FEI. On the other hand, FEI's commercial and industrial UPC increases with amalgamation, a function of the average UPC in those rate classes happening to be higher than pre-amalgamation average UPC in those rate classes. Similar to capture rates, the full effects of amalgamation on UPC will not be clear until the three year phase-in has happened. In the intervening period, it is reasonable to assess changes in energy use as presenting similar risks for FEI Amalco as they had presented for the benchmark utility FEI in the GCOC proceeding.

As shown in the Figure 27, amalgamated FEI's residential annual use per customer, or UPC, has declined by more than 12 percent since 2005.[38]

Figure 27: Amalgamated FEI's Residential (RS 1) Normalized UPC for Existing Customers



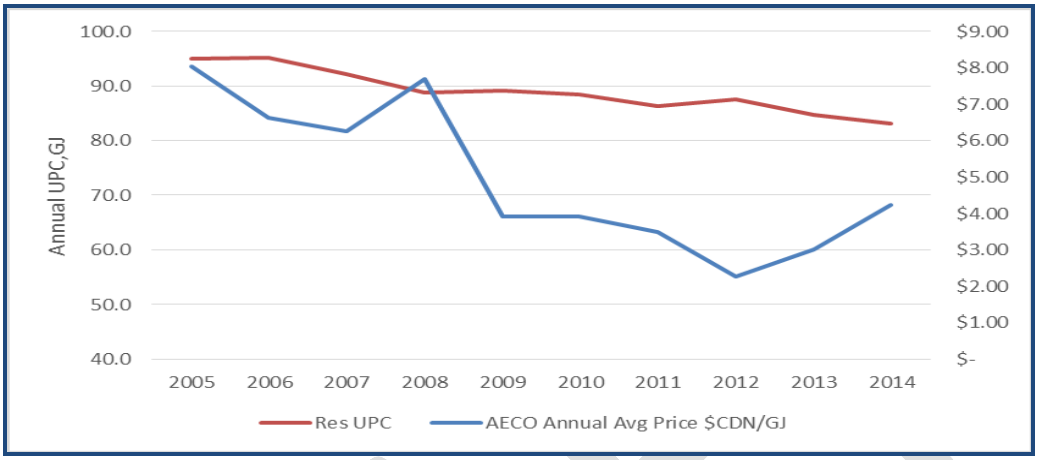
The decline in UPC is attributable to a variety of factors, including technological advances and energy efficiency improvements, building codes, size and type of homes being built, and type of appliance being installed in these homes. Commodity prices are also expected to influence customer use over time; however, actual changes in customer behavior in response to prices are difficult to determine from historical data.

[37] BC Hydro confirmed this expectation in its 2012 Integrated Resource Plan, stating: "Since row houses and apartments are more likely to be built with electric heat compared to single family homes, the market share for electrically-heated housing is expected to increase." (Appendix 2A, 2011 Electric Load Forecast, page 27).

[38] The use per customer rates are based on historical data. It is expected that new customers use per account will be much lower than existing customers for a variety of reasons.

As shown in Figure 28 below, for the residential sector, average use per customer decreased during the period of rising prices but UPC has not rebounded during the low price environment experienced over the last couple of years. This is likely due to the influence of these other factors.

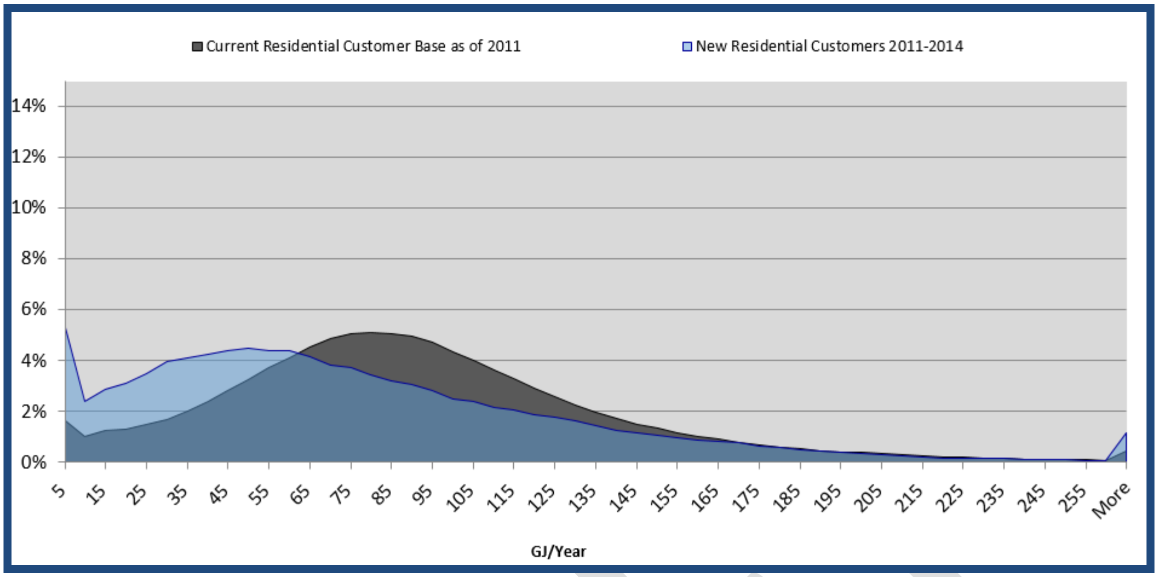
Figure 28: Amalgamated FEI's Residential UPC and Commodity Price



Short-run price elasticity reflects behavioural changes that a customer may make in response to changes in price, whereas changes in energy-consuming equipment (capital) would be captured in the long-run elasticity. Long-run elasticities are expected to be larger because customers can make adjustments in the capital stock.

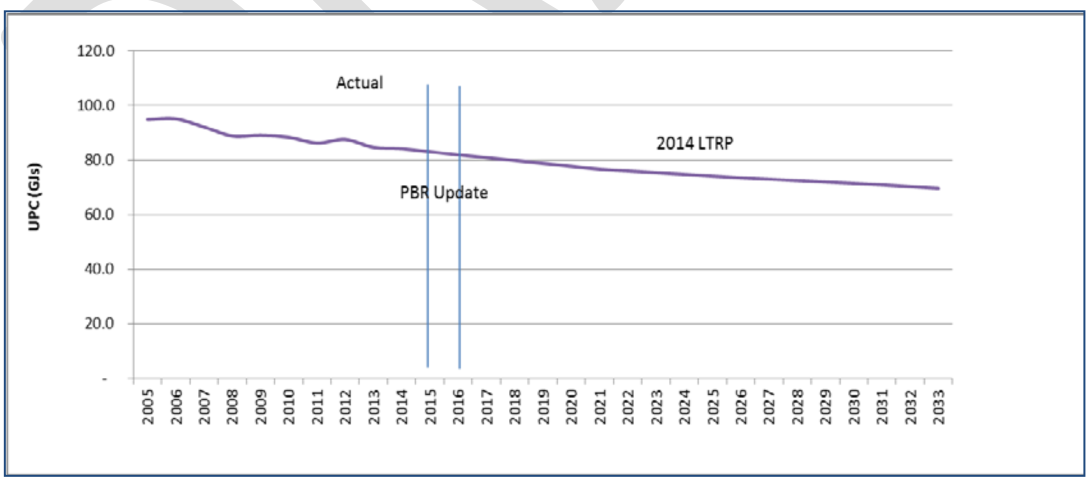
The implication of the research findings is that new customers will have a lower UPC compared to the existing customers as is illustrated in Figure 29. The frequency distribution curves for the existing and new customers are centered on 84.2 GJ and 68.3 GJ, respectively. This means that an existing natural gas residential customer on average consumes 84.2/GJ in a normal year as compared to a new residential customer which will consume 68.3/GJ in a normal year. This trend in UPC for new customer additions in the residential sector will have long-term impacts on the throughput from this sector.

Figure 29: Amalgamated FEI's Residential Frequency Distribution



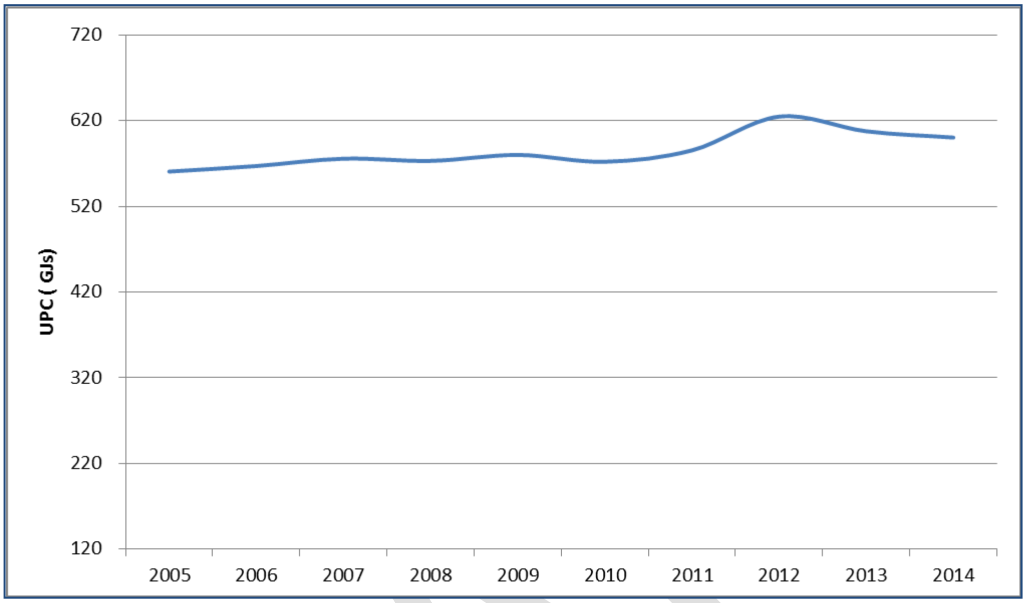
FEI's forecast of the decline in residential use rates is in line with the forecast from its 2014 Long Term Resource Plan (LTRP). As set out in the LTRP, natural gas consumption in the residential sector will naturally decline by an additional 8 percent from 2011 to 2033 (putting increasing pressure on delivery rates, all else equal), even in the absence of continued demand-side management. FEI also estimated in the LTRP that the total reduction as large as 12 percent on a cumulative basis from 2011 to 2033 can be achieved if new demand-side measures are implemented. Figure below illustrates the trend of amalgamated FEI's residential use rate for existing and new customers.

Figure 30: Amalgamated FEI's Residential UPC Actual and Forecast



FEI's commercial customers (Rate Schedule 2, 3 and 23) consist of customers from a wide variety of business sectors, as well as from condominiums and multi-family dwellings (greater than 4 units). Since this is a very diverse group of customers there are many factors affecting their natural gas use that may lead to counter-intuitive changes in the overall average commercial use rate. Figure 31 below shows the fluctuations in the annual use rate for the commercial rate class.

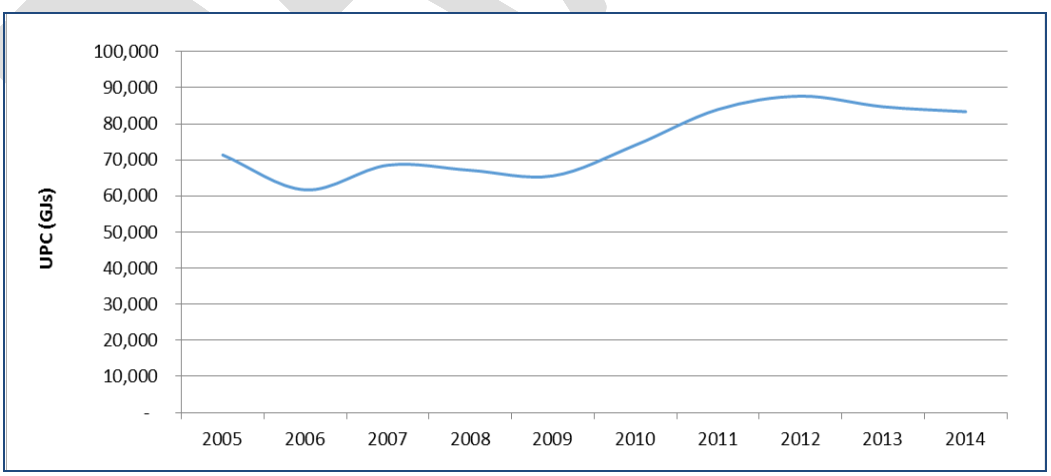
Figure 31: Amalgamated FEI's Commercial UPC



Forecasting the future use rate for the commercial rate classes is difficult due to high heterogeneity of customers in commercial rate schedules.

Amalgamated FEI's historical industrial UPC is displayed in Figure 32.

Figure 32: Amalgamated FEI's Industrial UPC



In 2010-2012, FEI amalco 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. However this increase was temporary as industrial customers' demand slightly decreased in 2013 and

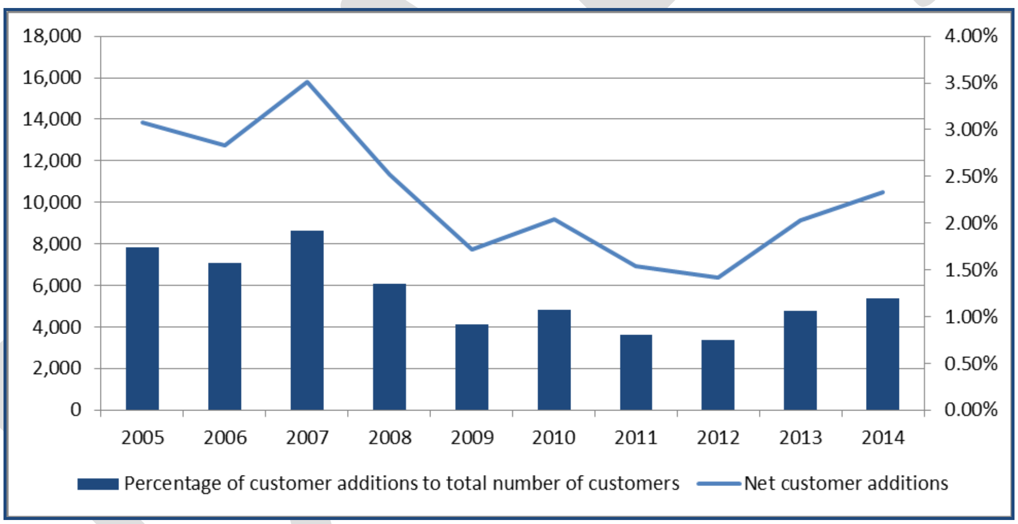
2014. These small variations in industrial demand are probably due to the price elasticity of demand for industrial customers as well as their business cycles.

6.5 Changes in Customer Additions

A further trend that compounds the declining use per customer is the weak capture rate for new building stock, primarily in the multi-family sector. FEI's ability to manage risk is in part dependent on its ability to attract and retain new customers to offset declines in UPC, and this is proving to be more difficult than it has been historically. These risk factors were present in 2012. FEI's assessment is that changes in customer additions present similar risks for FEI Amalco as it had presented for the benchmark utility FEI in the GCOC proceeding.

As shown below in Figure 33, amalgamated FEI's net customer additions increased in 2013 and 2014[39] however this increase was too small to compensate for the declines in the number of FEU customer additions over 2007-2012 period. FEI added a little over 10,000 residential customers (net of attrition) in 2014, which represents approximately 1.25 percent of the total number of customer in 2014.

Figure 33: Amalgamated FEI's Residential Customer Additions

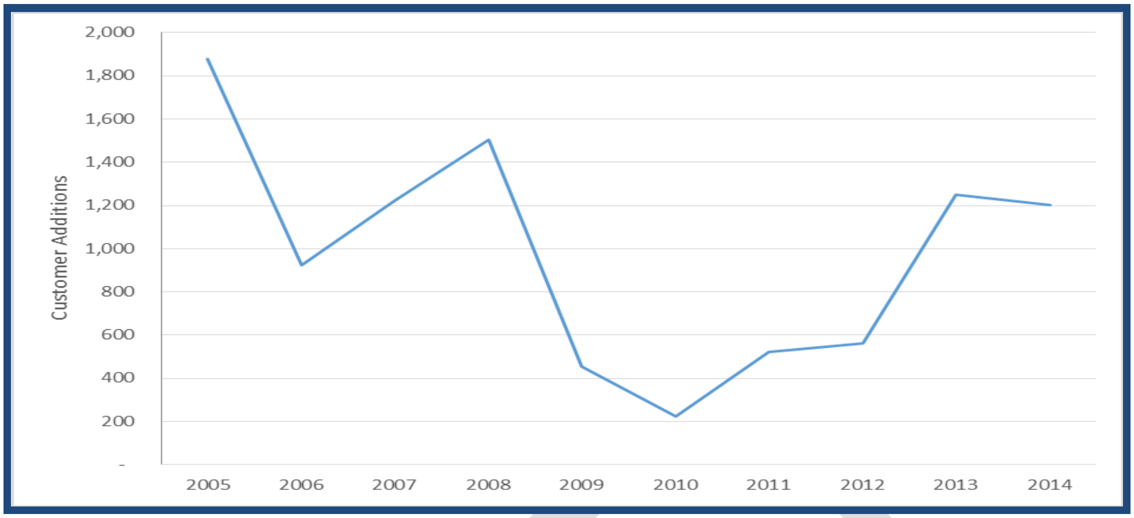


Residential customer additions are influenced by a number of factors, including the new construction market in BC, and the previously-discussed shift in the housing market towards more higher-density housing types where the Company has a low capture rate.

For commercial customers, as demonstrated by Figure 34, net customer additions are highly volatile and do not exhibit a clear trend.

[39] In 2013 and 2014, FEI undertook an initiative to repatriate customers that had a meter and service line but who had stopped taking service from FEI over the past few years. This resulted in a number of residential as well as commercial net customer additions.

Figure 34: Amalgamated FEI's Commercial Customer Additions



FEI does not forecast industrial customer additions and relies on customer surveys to determine throughput levels for the industrial sector.

7. ENERGY SUPPLY RISK

Supply risk relates to the physical availability of the commodity and the ability to reliably transport it using third party pipelines to FEI's system for delivery to end-use customers. Supply risk for gas utilities, broadly speaking, includes the possibility of supply interruption, which stems from the degree of reliance on a single supply basin, reliance on a single transportation pipeline, and the availability of regional storage. It also includes the timing and degree of long-term investment in developing and maintaining production, as well as adequate transportation pipeline capacity that is needed to bring production to market.

The analysis of supply risk is separated into two sections: (1) FEI's supply availability, that remains largely unchanged from 2012, and (2) security of supply risk, which has slightly increased compared to that of the benchmark utility in the pre-amalgamation period.

7.1 Availability of Supply

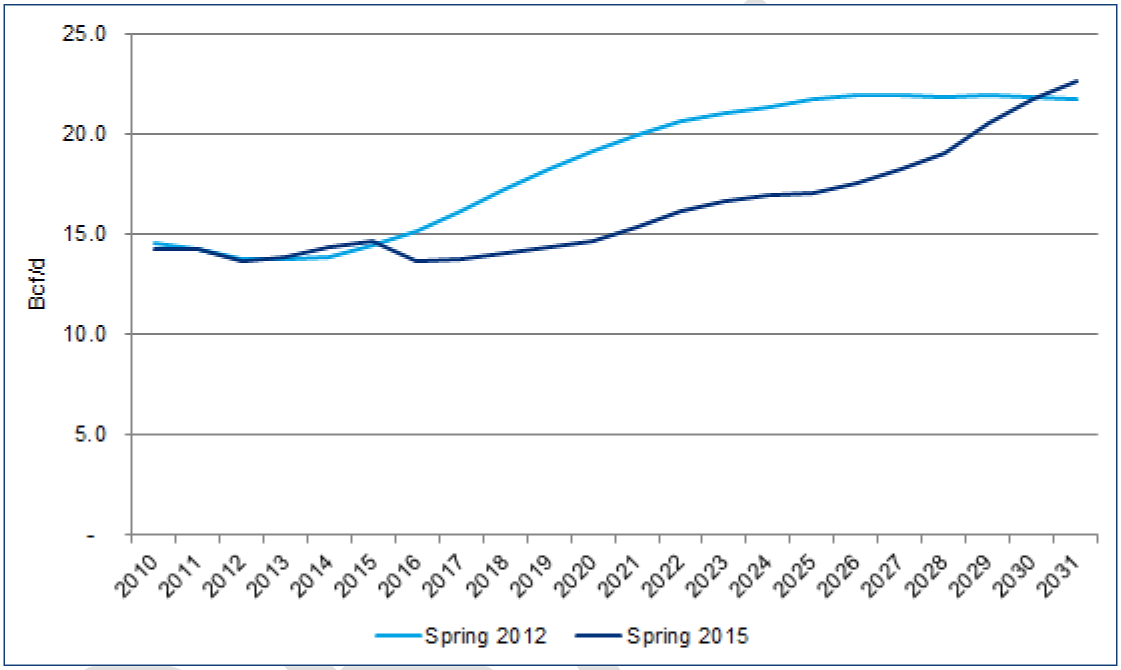
In the oil and gas industry, supply availability is typically separated into upstream activities, referred to as exploration and production (E&P) and midstream activities that include the storage and transportation of energy. Amalgamated FEI continues to source gas supplies from the same market hubs as prior to amalgamation. In addition, the integrated operation of the FEI, FEVI, and FEW transmission and distribution systems that existed before amalgamation means that amalgamation itself has had little impact on supply availability for FEI (FEVI and FEW were already connected to FEI's coastal transmission system, and FEVI's Mt. Hayes LNG facility was already used to balance gas supply in FEI's network).

In the next sections, upstream and mid-stream risks of FEI are analyzed in more detail.

Upstream Activities

FEI and other utilities in the U.S. PNW are supplied mainly by natural gas that originates from the Western Canadian Sedimentary Basin (WCSB)[40]. Figure 35 illustrates the actual and previous and recent forecast levels of supply from the WCSB.

Figure 35: WCSB Production (Actual and Forecast)[41]



As demonstrated in Figure 35 the forecast for natural gas production indicates that production is expected to increase steadily after 2016. It also shows that the recent forecast (Spring 2015) has been lowered from the previous forecast (Spring 2012) until the forecasts converge at the end of the forecast period in 2031. This is a reflection of the decrease in gas and oil market prices as well as the potential delay in Alberta oil sands development projects. The increase, albeit slower in the recent forecast, is dependent on rising prices and LNG exports supporting higher drilling levels. The large reserves of shale and tight gas located in northeast BC will not however result in higher production levels unless there are markets for new production. Furthermore, the need for new markets for production from the WCSB has become critical as current production is being pushed from traditional markets in northeastern North America. Traditional eastern markets for WCSB gas are becoming less dependent on WCSB gas because of

40 The WCSB is a vast gas producing basin of 1,400,000 square kilometres in western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories. U.S. PNW utilities also access portion of their gas supply from the Rockies basin in the United States.

41 Wood Mackenzie North America Gas Service.

the availability of and accessibility to a large volume of gas supply from large scale supply sources located in the northeast U.S., such as the Marcellus and Utica shale gas basins. In the future, existing production and increases from new producing areas in the WCSB will also be driven by increased regional demand, including demand from oil sands development and expansion of gas-fired generation load in Alberta. LNG exports will develop if production can be cost effectively connected to overseas export markets. If these new markets do not occur, then the natural gas located in large areas of the WCSB, and especially the significant resource located in the frontier areas of northern BC, will remain trapped. Should this outcome occur, it will be more difficult and costly in the future to secure the natural gas FEI requires.

Midstream (Transportation and Storage)

As described in the 2012 GCOC application, even under a production increase scenario in NEBC, there is still no guarantee that the incremental production levels lead to a more cost effective supply for FEI customers. Access and cost are affected by a variety of factors.

Amalgamated FEI continues to contract with third parties such as Spectra, Northwest Pipeline (NWP), and TransCanada's NOVA Gas Transmission Ltd. (NGTL) and FoothillsBC for transportation capacity in order to move supply purchased at different market supply hubs, and to complete withdrawals and injections from storage facilities, for delivery to its system. Table 8 below provides a summary of FEI's main sources of supply as well as the related supply hubs. The FEI's main supply sources have not changed since 2012 GCOC application.

Table 8: Summary of FEI's Main Sources of Gas Supply

Pipeline name	Supply Source	Main Hub	Level of importance
Spectra's Westcoast Energy Inc. (WEI)	NEBC	Station 2	Approximately 75% of FEI's gas is accessed via West Coast system. Also used for daily balancing via the Aitken Creek storage facility.
NGTL /FoothillsBC	Alberta	AECO/ NIT	Approximately 25% of FEI's gas is accessed via the NGTL and the FoothillsBC system from AECO/NIT. Also provides access to some storage capacity.
Northwest Pipeline	Washington; Oregon storage facilities	Sumas	FEI does not currently contract for Sumas supply but in the future it may provide additional security of supply during winter and peak periods if additional infrastructure is constructed.

As indicated in Table 8, FEI remains heavily dependent on gas supply from northern BC that is transported on Spectra's WEI pipelines. There are a number of communities served by FEI in north-central BC that are entirely dependent on supply from WEI's T-South because there is no other infrastructure available for transporting natural gas to these locations. Outages or operational issues on WEI's system or in the producing regions can result in supply shortages on FEI's system.

FEI is in competition with utilities in Alberta and the U.S. PNW for storage and transmission capacity. Shorter duration market storage facilities are largely owned by utilities in the U.S. PNW and they have been utilizing an increasing share of those resources for their own use. In addition, the pipeline capacity to the Alberta marketplace from NEBC production has expanded considerably in the recent past, which provides optionality for producers to bypass the BC and Station 2 marketplace altogether.

Another critical factor regarding FEI's access to cost effective supply relates to regulatory proceedings in other jurisdictions. There are currently several NGTL and WEI infrastructure and rate design applications that either are or will soon be before the National Energy Board (NEB). The decisions regarding these applications could have an impact on the market in western Canada and impact FEI's supply procurement activities. Toll increases on pipelines and competition for BC gas supply from the Alberta marketplace, or Asian markets for LNG, could all put upward pressure on the cost of natural gas for customers in BC.

The NGTL North Montney Project proceeding is an appropriate example for further elaboration on this issue. Although the primary purpose of NGTL's project is to move gas produced in NEBC to serve the LNG export market, NGTL sought to have the project considered an extension of its Alberta system, including the application of its toll methodology. However in its report, the NEB attached several conditions to its recommended approval of the project, including the establishment of separately tolled project facilities unless NGTL comes forward with a new toll proposal. NGTL is expected to come forward with a proposal for a new toll methodology for these facilities that would allow them to be considered an extension of its existing system. NEB approval of such a proposal would impact FEI's ability to continue to access natural gas supply for its customers at competitive market prices, reduce liquidity at the Station 2 hub and increase FEI's cost of holding firm transportation capacity and storage resources. Shippers that today flow gas on T-North and move gas to the Station 2 or Alberta market could alternatively simply bypass the WEI system. Any reduction in the use of T-North and T-South systems will increase the costs to their captive shippers such as FEI[42].

Due to recent regional market changes, there is a new supply risk to customers that rely on Spectra's Westcoast T-South system. New demand from projects either announced or being considered in the Lower Mainland and U.S. PNW have the capability of filling up long term T-South firm capacity.

[42] Progress is currently the largest T-North shipper on Westcoast. If Progress were to transfer those volumes to NGTL it could have a significant impact on the utilization and tolls of the T-North and T-South systems.

A significant volume of gas supply serving industrial customers in the Lower Mainland uses the T-South system to flow on an interruptible basis, which means their gas supply is at risk of being cut as less uncontracted transportation capacity is available. Any major decrease in the future availability of transportation capacity risks leaving these customers without adequate gas supply or they will need to pay significantly higher commodity prices at Huntingdon before any infrastructure expansions can be completed. Given that these industrial customers have not made a commitment to hold transportation capacity in the past this may present some challenges for these customers moving forward.

The supply risk to FEI's customers and other PNW utilities increases if new demand is added and there continues to be a lack of new pipeline transportation capacity. At this time, the only new industrial demand is for FEI's Tilbury LNG facility expansion project. The potential new loads from other potential projects are still pending, so in the short term the risks in terms of physical supply to meet the physical demand remains the same. However, if new load is added to the existing regional pipeline infrastructure, then supply constraints will increase FEI's throughput risk.

Jurisdictional Comparison

The supply and infrastructure for natural gas in BC is significantly different from jurisdictions elsewhere, such as those in Alberta and Ontario. The key differences relate to overall marketplace liquidity, the number of storage facilities and pipeline companies that operate in the Alberta and Ontario regions compared to BC. In addition, the amount of gas that flows in the Alberta/Ontario systems compared to BC is different.

The Alberta marketplace is a very liquid marketplace on a year round basis as it consists of a wide range of suppliers and resellers who are available on a daily basis to buyers. In addition, gas supply is readily available to buyers and sellers on an intraday basis each day in order to manage gas demand within a utility's operating region. The high level of gas flow in the Alberta market combined with a variety of available storage facilities provides gas supply to customers with no service disruptions in the event of gas plant outages. The close proximity of gas production to market and load centers also reduces the risk of gas supply disruptions for consumers. Although conventional Alberta gas production is declining, the availability of shale gas from BC coupled with significant increases in pipeline connectivity between BC and Alberta is anticipated to maintain the strength and liquidity of the Alberta marketplace.

The natural gas marketplace in Ontario is experiencing change whereby that region has started to benefit from shale gas supply located in close proximity to its operating region from basins such as the Marcellus and Utica. In addition, Ontario has historically benefited from sizable storage and deliverability within close proximity to load and market centers. Furthermore, the large Ontario gas utilities, Union Gas and Enbridge Gas, are owners and operators of the storage facilities in the area. Ontario's primary trading hub, the Dawn Hub, can access natural gas from the WCSB as well as a number of U.S. supply basins through a variety of pipelines feeding into the Dawn Hub. With the expansion of pipeline capacity, this hub will be able to readily access gas from the Marcellus region. Unlike the BC and PNW marketplace, where storage is limited, approximately 265 PJ of underground gas storage owned and operated by utilities also connect into the Dawn Hub providing substantial operational flexibility for the region. These differences compared with BC are important because they provide the Alberta and Ontario marketplaces with much more secure access to gas supply and are thus lower risk than the circumstances faced in BC.

7.2 Security of Supply

Security of supply relates to FEI's ability to provide gas supply to its core customers under extreme conditions and emergency situations. Compared to the situation set out in the 2012 GCOC Application where the benchmark utility FEI did not include the Vancouver Island and Whistler service areas, amalgamated FEI's supply interruption risks have increased somewhat.

- Both Vancouver Island and Whistler service areas are downstream of the mainland Coastal Transmission System. They are dependent on a pipeline system that traverses challenging terrain.
- Vancouver Island is supplied with three twinned submarine crossings ranging from 10.9 to 23.7 km in length. While the probability of a total failure of a submarine crossing is small, there is some additional risk associated with the difficulty of repairing a submarine crossing to maintain uninterrupted service once the gas supply that is held in the Mt. Hayes LNG facility has been depleted.
- Whistler is served by the pipeline lateral between Squamish and Whistler, which faces single point of failure risk. Whistler also does not have any on-system storage facilities that can be used to maintain service in emergency situations.

8. OPERATING RISK

Operational risk can be defined as the physical risks to the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography and weather. FEI has addressed operating risks in this section with reference to:

- infrastructure integrity,
- third party damages, and
- unexpected events.

There have been no changes to the operating risk facing the facilities on the Mainland since 2012. The addition of FEVI and FEW to the amalgamated FEI has had no material impact on the risk associated with infrastructure integrity, third party damages and unexpected events because the nature of the risk in all three cases is the same as on the Mainland.

8.1 Infrastructure Integrity

Nearly a quarter of distribution mains and approximately a third of intermediate and transmission pressure pipelines have been in service for more than 45 years. A growing percentage of assets have been in service for more than 45 years. FEI anticipates that over the next 40 years approximately two-thirds of current assets will need to be replaced.

The operating risk presented by assets relates to the ability of service providers to respond to long-term utility infrastructure replacement programs. There are many variables impacting the useful life of underground pipe including pipe material, pipe coating, soil conditions, external interference, corrosion, etc. FEI has several programs in place to monitor, inspect and assess pipe condition and as a result of these assessments has developed longer term capital programs to replace sections of pipe that are reaching the end of their useful life. The primary challenges in terms of executing on infrastructure replacement plans are, firstly, in obtaining regulatory approvals, and secondly, in obtaining project resources to perform the work. These would include a mix of project managers and engineers, planners and field resources, etc. Other natural gas companies in the country as well as other utilities in the province (particularly BC Hydro) are competing for the same resources over similar time periods potentially driving up service provider costs.

As the trends were understood in 2012, the Company has assessed infrastructure integrity risk facing the amalgamated FEI to be similar to the risk facing the benchmark utility in 2012.

8.2 Third Party Damages

Third party damage refers to a third party either accidentally or deliberately damaging gas assets below ground or above ground. Below ground damage is usually caused by a contractor, municipality or homeowner excavating in the vicinity of gas infrastructure, following unsafe excavation practices and damaging the gas main, service line, or meter which may result in the loss of gas, service interruptions and significant repair costs. The number of incidents of third party damage has been on a decreasing trend since 2006. Deliberate third party damage (vandalism, theft, sabotage, terrorism, etc. usually in relation to above ground facilities) remains a relatively low frequency event in FEI in comparison to excavator third party damage. As this trend was understood in 2012, the Company has assessed third party damage risk facing the amalgamated FEI to be similar to the risk facing the benchmark utility in 2012.

8.3 Unexpected Events

Amalgamated FEI has a large radial system through river, watersheds, mountainous and forested terrain, which is subject to more hazards than operating a natural gas system on the prairies, for example. Natural events contributing to operating risk in BC include floods, washouts, forest fires, land slippage and earthquakes. While the timing of these events is somewhat unpredictable and cyclical in nature, FEI has systems in place to mitigate the impacts of these natural forces. In many cases, proactive emergency planning can further reduce the impacts of these events. However, given that the extent of these natural events remains unpredictable, they pose one of the higher operating risks to FEI.

The magnitude of this risk has not changed materially since 2012. The Vancouver Island and Whistler service areas traverse broadly similar topography and conditions to the Mainland.

9. POLITICAL RISK

Political risk can be defined as the potential for government to intervene directly in the utility regulatory process or negatively impact utility operations through policy, legislation and/or regulations relating to such issues as tax, energy and environmental policies, industry structure, safety regulations and Aboriginal Rights. The political landscape is a significant risk factor for FEI.

Based on the above definition, the subsections below focus on climate change policies and legislation, GHG emissions reductions requirements, carbon tax, and aboriginal rights. Similar to 2012 the BC government's energy policies and legislation continue to discourage the use of natural gas in FEI's traditional markets (space and water heating) while promoting the new initiatives such as NGT and LNG export. Further, local governments and municipalities have intensified their efforts to promote "green" initiatives that hinder the development of natural gas in space and water heating sectors. A new development since 2012 was the Supreme Court of Canada's ("SCC") 2014 Decision in *Tsilhqot'in Nation v. British Columbia,* which highlighted the risks faced by companies such as FEI with regards to Aboriginal issues. These developments are discussed in more detail in the following sections.

All things considered, it is assessed that the amalgamated FEI's political risk is higher than the risk level identified in 2012 for the benchmark utility FEI.

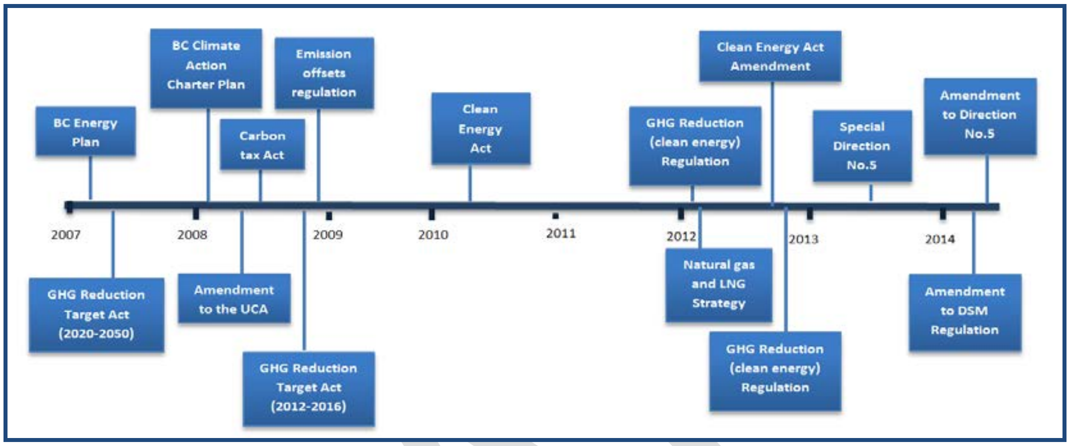
9.1 Provincial Government's Energy Policies and Legislation

The BC government's energy policy and legislation has played a significant role in the risk assessment for FEI in the past. Similar to 2012, the role of natural gas in BC's Government energy policy continues to be focused on the role of natural gas in the transportation market and LNG export, as opposed to FEI's core business of space and water heating. FEI's core business will continue to be in the natural gas distribution for space and water heating for the foreseeable future, and it is within this market that FEI faces continuing challenges from policies and legislation that favour other energy sources.

Since 2007, the BC provincial government has enacted a number of significant pieces of legislation in pursuit of its environmental and low carbon economy policies. These policies and related legislation have put substantial pressure on natural gas in its traditional role in providing heat for space and water heating, while creating some opportunities in non-traditional and less significant areas such as natural gas for transportation. The legislation includes ambitious greenhouse gas reduction targets, BC's Carbon Tax Act and the 2010 Clean Energy Act (CEA) which have focused on the role of clean and renewable energy, and energy conservation to meet the energy demands of the province, while at the same time reducing the competitiveness and ultimately the consumption of fossil fuels in BC.

Figure 36 provides a snapshot of all the recent energy and climate change policies and legislation developed in the Province, most of which were discussed in previous cost of capital proceedings[43].

Figure 36: Energy Policy and Legislation Timeline



Since the GCOC stage 1 filing, the BC government has introduced three new minor amendments to existing regulations and has issued a special direction to the BCUC for development of LNG facilities in BC. The three amendments are to the *Clean Energy Act* (CEA), the *Greenhouse Gas Reduction Regulation* (GGRR), and the *Demand-side Measures (DSM) Regulation*. Each of these developments are briefly discussed below. They do not represent a change in policy direction since 2012.

Amendment to the Clean Energy Act

In June 2012, BC's Energy Objectives Regulation modified[44] (in bold typeface) section 2(c) of the *CEA* to "generate at least 93 percent of the electricity in British Columbia, **other than electricity to serve demand from facilities that liquefy natural gas for export by ship**, from clean or renewable resources and to build the infrastructure necessary to transmit that electricity." The change to the designation of natural gas as a source of clean energy for the purpose of LNG export enables production of electricity to fuel the LNG export market without compromising the requirements of the *CEA*. As a result, natural gas can be used for both liquefaction and as a power-generating fuel in LNG production, with the result of an increase in demand for natural gas in BC, and the potential for higher commodity prices. This amendment was giving effect to the BC LNG Strategy that had been discussed in the GCOC proceeding.

[43] Please refer to 2009 ROE and capital structure proceeding as well as 2012 GCOC proceeding for detailed discussions.

[44] Deposited on July 25, 2012.

The power required for FEI's LNG facilities (Tilbury and Mt. Hayes), as well as the proposed Woodfibre LNG facility, is supplied by BC Hydro and therefore this amendment has no impact on natural gas demand in FEI's service territory in the short and medium-term.

Amendment to the Greenhouse Gas Reduction Regulation

On November 28, 2013, the BC government amended the GGRR to include mine haul trucks and locomotives as vehicles eligible for incentives, while increasing expenditure caps on items such as grants for safety practices or maintenance facilities, expenditures on stations and a tanker truck load-out facility. This amendment provides FEI with new opportunities in NGT markets; however, the market for the use of natural gas for locomotives and mine haul trucks is in its infancy and should have no significant impact on FEI's throughput in the near-term.

Amendment to the Demand-side Measures (DSM) Regulation

On July 10, 2014, the provincial government deposited BC Reg 141/2014 (the Amendment) which modified the prior *Demand-Side Measures Regulation*. The Amendment raised the low income program eligibility threshold and added a deemed list of eligible low income customers. Additionally, it changed the calculation of FEI's cost of energy for the modified total resource test. However, these changes do not result in an expansion of FEI's Energy Efficiency and Conservation spending and have no impact on FEI's risk profile.

Special Direction No. 5 to the BCUC

In November 2013, the BC Government issued BC Reg 245/2013, Special Direction No. 5 to the BCUC under Section 3 of the *UCA* (Direction No.5). Direction No.5, in its original form, exempted from review expenditures on an expansion of the Tilbury LNG facility up to $400 million, and effectively lowers the LNG dispensing rate to $4.35 per GJ. These developments represent a significant addition to rate base, which in isolation would place upward pressure on rates. It is expected, however, that the project will add throughput and generate counterbalancing benefits through the revenues from LNG sales. As the Tilbury LNG facility project is still in its early stages of development, FEI has assessed the project as currently having no material impact on the business risk of FEI Amalco, either favourable or unfavourable. Over the longer-term, the NGT and LNG market could help to mitigate rising business risk due to trends in the core business.

Amendments to Direction No.5 to BCUC

On December 22, 2014, the BC government deposited BC Reg 265/2014 (Order in Council No. 749) which amended Direction No.5. The amendment includes the following major components (each of which will be described in more detail below):

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(i) Additional Expansion at Tilbury LNG facility (Phase 1B):

The Direction No. 5 amendments expand the Tilbury facility expansion project into two separate phases (1A and 1B) each of which is subject to a cap of $400 million plus AFUDC. Phase 1A is identified as the initial CPCN exemption of $400 million plus AFUDC for Tilbury LNG facility expansion project as defined in Direction No.5. Phase 1B includes an additional CPCN exemption for a second block of $400 million plus AFUDC for the Tilbury expansion project to provide additional liquefaction capacity (it does not include storage). The liquefaction capacity of Phase 1B must be 70 percent contracted (on average) over the first 15 years of operation before proceeding with construction. Contracts eligible for inclusion in the 70 percent average calculation must include take-or-pay obligations for at least 10 years and be 10 years or more in duration.

(ii) Rate Schedule (RS) 50 – Large Industrial Transportation Service Rate Schedule:

The amendment requires the BCUC to approve a new Rate Schedule (RS) 50, designed for large volume firm transportation service for large industrial customers. Among other things, the terms and conditions of this new RS include a minimum of 45 TJ firm daily demand and 15 year contract term. The RS 50 rate structure is designed to recover the costs of incremental capital investments required to serve RS 50 customers with incremental revenue providing additional contribution to existing natural gas rate payers that will offset the costs associated with the incremental capital.

(iii) Transmission project CPCN exemptions:

The amendment also exempts from the Commission's review the following transmission projects:

1. Coastal transmission system (CTS) capacity expansion projects: They include CPCN exemptions for the four Transmission pressure (TP) projects; namely three projects from the LMSU (Cape Horn to Coquitlam, Nichol to Port Mann, Nichol to Roebuck) and one on Tilbury Island to increase pipeline capacity into the LNG plant.

2. EGP Project: The Direction No.5 amendments further exempt from review, expenditures related to the potential EGP project.

(iv) FortisBC-BC Hydro Letter Agreement:

The FortisBC-BC Hydro letter agreement amends several agreements between BC Hydro and FEI and FEVI related to BC Hydro's capacity on the FEI and FEVI systems to deliver gas to Burrard Thermal and the Island Generation (IG) facility in Campbell River. The letter agreement deals with the BC Hydro's much-reduced need to transport gas across the FEI system after the impending permanent closure of Burrard Thermal takes place. After that occurs BC Hydro will only require transportation capacity to deliver gas to the Island Generation facility on Vancouver Island. In addition the letter agreement permits BC Hydro, under certain conditions to use its delivery capacity to deliver gas to the Woodfibre LNG facility if and when that facility goes into service.

9.2 GHG Emissions Reduction and Local Governments Initiatives

As has been the case for a number of years, BC continues to be at the forefront amongst those jurisdictions pursuing significant GHG reduction initiatives. The general implications of these provincial policies for FEI's business risk remain consistent with FEI's characterization in the Stage 1 GCOC evidence. Local governments have also been assuming an increasingly important role in GHG emission reduction policy implementations and the codes and recent initiatives by local governments may have significant consequences on FEI's ability to attract new customers and retain existing ones (in some cases local governments have higher GHG emission reduction targets than the provincial government). The increased willingness of local governments to dictate energy choices represents a material increase in risk for FEI.

(i) Provincial Emission Reduction Targets

The measures put in place in BC, which include a focus on reducing the use of natural gas in heating applications, has a disproportionate impact on BC natural gas utilities. Each of the four provinces examined has instituted various measures to reduce GHG emissions within its jurisdiction. Table 9 shows GHG emissions reduction targets in British Columbia, Alberta, Ontario and Quebec. Compared to 2012, these targets have remained unchanged[45].

Table 9: GHG Emissions Reduction Targets in Four Jurisdictions across Canada

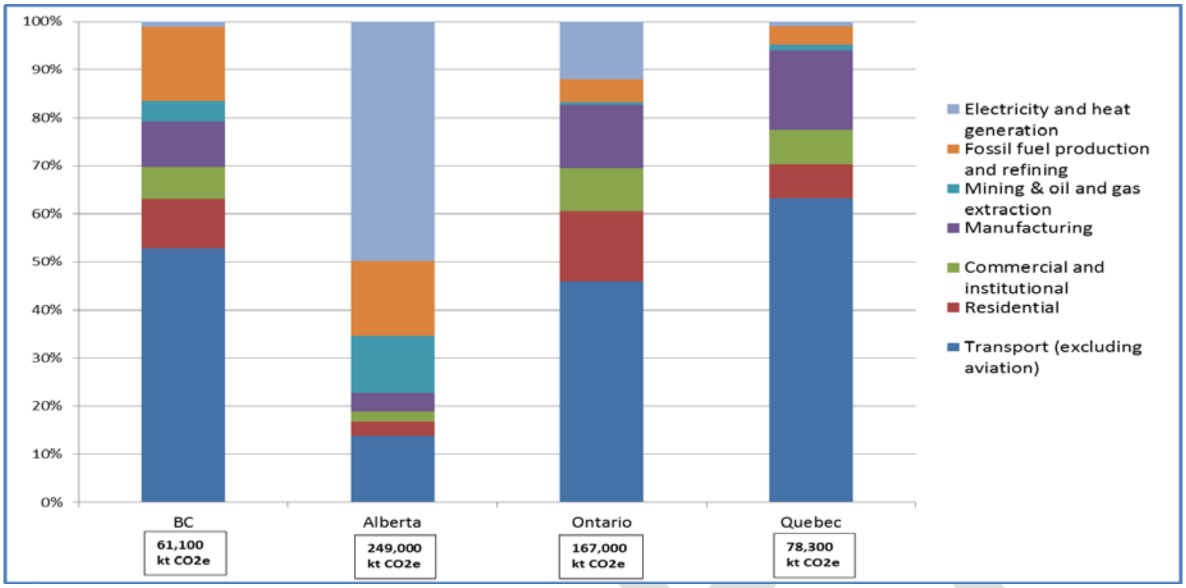
Province	GHG Emissions Reduction Targets
British Columbia	Reduce by 33% below 2007 level by 2020 Reduce by 80% below 2007 level by 2050
Alberta	Reduce by 50 megatonnes below business as usual by 2020 Reduce by 200 megatonnes below business as usual by 2050 (Reduce by 14% below 2005 levels by 2050)
Ontario	Reduce by 15% below 1990 levels by 2020 Reduce by 37% below 1990 levels by 2030 Reduce by 80% below 1990 levels by 2050
Quebec	Reduce by 20% below 1990 levels by 2020

Source : Environment Canada, 2014; Canada's Emission Trends

Furthermore, as Figure 37 demonstrates, the GHG emissions profile of each province is significantly different from the others.

[45] In May 2015, Ontario Government introduced a new mid-term target while keeping the long-term and short-term targets intact.

Figure 37: GHG Emissions Profile for Major Energy Sector Categories across Four Jurisdictions in Canada* (2012)



Source: Environment Canada National Inventory Report 1990-2012 data
* The values in boxes underneath each column represent the total GHG emissions in all sectors for 2012 rather than just the major selected categories included in the columns

Differences among the provinces in their GHG emissions profile can lead to different GHG emissions reduction solutions within each province. For instance, as demonstrated, close to 50 percent of Alberta's GHG emissions are related to power and heat generation which is caused by Alberta's traditional reliance on coal fired plants. This implies that a shift from coal to natural gas for electricity generation in Alberta will have the effect of reducing GHGs from electricity generation. On the other hand, in provinces such as British Columbia and Quebec with abundant hydro resources available, the GHG emissions in power and heat production sector are minimal and therefore in order to achieve the GHG emission targets the government must target other areas such as the transportation sector as well as the residential and commercial sectors.

BC provincial government has recently announced that it is planning to build on the success of its 2008 Climate Action Plan and develop a new "Climate Leadership Plan" to review the options available for reinforcing the provincial efforts to reduce GHG emissions. Although this plan is in its initial development stages (the government is currently seeking comments on its Climate Action Plan Discussion Paper), it creates additional uncertainty.

(ii) LOCAL GOVERNMENTS

Furthermore, legislation continues to require all BC local governments to set GHG reduction targets at the municipal and regional district level. The majority of BC's local governments have signed the Climate Action Charter, pledging to take action to significantly cut both corporate and community-wide greenhouse gas emissions. Local governments can achieve carbon neutrality by reducing emissions, by purchasing carbon offsets to compensate for their greenhouse gas emissions or by developing projects to offset emissions. Such projects may include improving the energy efficiency of local government-owned and operated buildings and vehicle fleets[46].

On September 24, 2008, the Province announced the Climate Action Revenue Incentive Program (CARIP) to offset the carbon tax for local governments who have signed the B.C. Climate Action Charter. Since 2008, this provincial fund has provided more than $32.5 million to help support B.C. communities' efforts to reduce greenhouse gas emissions and work toward their Climate Action Charter goals (according to the B.C. government News release on April 22, 2015, communities throughout B.C. received more than $6.5 million with the latest rounds of grants through this incentive program) [47]. To be eligible for the program, municipalities are required to report annually on the steps they are taking – and progress they have made – to become carbon neutral.

Based on a review of the corporate and community-wide actions[48] reported over 2010, 2011 and 2012, some overall trends regarding local governments' corporate and community-wide effort reduction efforts have emerged[49]. For instance, on the corporate side, the "building and lighting" category has encompassed over one third of the total direct actions[50] throughout the three reporting years. Further, on community-wide efforts, policy development actions such as update of building codes for emission reductions have been at the forefront of the "supportive actions"[51] taken by municipalities. The table below presents some of the types of actions in each of these major categories for corporate and community-wide efforts.

Table 10: Examples of GHG Reduction Direct and Supportive Actions Reported in Corporate and Community-Wide Spheres

	Community-Wide	Corporate
Direct Actions	Use of sustainability checklists for new buildings, Grants for improved residential energy efficiency, District energy and energy exchange systems, Geothermal, …	Solar heating for municipally owned buildings, building retrofits to improve heating efficiency, , …
Supportive Actions	Revised Official Community Plans (OCPs) to include GHG reduction targets, policies and actions,	corporate climate action plans, corporate

[46] http://www.cscd.gov.bc.ca/lgd/greencommunities/climate_action_charter.htm.
[47] http://www2.news.gov.bc.ca/news_releases_2013-2017/2015CSCD0020-000548.htm
[48] Local government corporate actions refer to efforts by local governments to reduce their own emissions. Overall, through the purchase of offsets and by undertaking measurable emission reduction projects, in 2013 BC local governments reduced their reported corporate greenhouse gas emissions by over 127,290 tonnes. Community-wide actions refer to the efforts that require the support of the greater community.
[49] http://www.cscd.gov.bc.ca/lgd/library/CARIP_2013_Summary_Report.pdf
[50] Direct actions are those that can be directly implemented and the impacts directly measured (e.g. installation of an energy efficient heating system).
[51] Supportive actions provide the framework to support implementation of direct action (e.g. development of policies, education programs, feasibility exploration). For clarity, the designation is not FEI's assessment of whether or not these initiatives are helpful or detrimental to its business.

	Development of Climate Action Plans, Community Energy and Emissions Plans, Development of policies related to buildings, transportation and waste (e.g. green building strategies), …	building policies, corporate fleet and energy use policies, …

The trends seen over the past number of years have solidified. Municipalities are making significant changes to their operations, policy, codes and regulations, which are having a direct negative impact on natural gas throughput. For instance:

- As part of the City of Vancouver's "Greenest City 2020 Action Plan", it is required that all new larger buildings – specifically, buildings classified in the building Bylaw as Part 3 and Part 9 non-residential buildings –be designed to strict energy standards. Energy reduction targets for new buildings are 20 percent below 2007 levels by 2020, and "carbon neutral" by 2030. The City also introduced Canada's first energy code/bylaw for existing larger buildings classified as Part 3 and Part 9 non-residential[52]. The 2020 energy reduction target for existing larger buildings is to reduce greenhouse gas emissions to 20 percent below 2007 levels[53].

- Further, under the City of Vancouver's "Green Home Program", new one and two-family homes are required to include a number of sustainable features that are focused on energy savings up to 33 percent by the year 2020. It is projected that the Vancouver Green Homes Program will be 14 percent more effective in reducing GHG's in new dwellings than what has recently been introduced in the Provincial Building Code. For instance, the recent amendments to Vancouver's by-law mandates that for the boiler or furnace upgrades of over $5000, the annual fuel utilization efficiency (AFUE) shall be equal or more than 90 percent. The AFUE of 90 percent requires a condensing system. Generally speaking with old homes, it is expensive to convert the existing venting system to accommodate the venting system that is required for a condensing unit which can lead to a migration of existing customers from natural gas condensing boiler/furnaces to electric ones.

- The recent amendment to the City of Richmond bylaws (amendment bylaw 9147) requires that new townhouses be designed (a) to score 82 or higher on the EnerGuide Rating System (this is higher than the EnerGuide score of 77 that is currently required by the BC Building Code) and (b) be solar hot water-ready. Alternatively, new townhouses will be exempt from the above if they connect to a

[52] Vancouver is the only municipality in BC with its own building by-law. On April, 2014, the City Council enacted the 2012 BC Building Code with additional requirements and revisions specific to Vancouver.

[53] http://vancouver.ca/home-property-development/large-building-energy-requirements-forms-checklists.aspx.

district energy utility or install industry proven renewable energy systems (such as geo-exchange, solar water heating, photovoltaic energy) which provide the majority (at least 51 percent) of heating, cooling and/or electrical energy load requirements[54].

- In 2012, Surrey City Council approved the District Energy System By-law which includes the requirement for all City Centre developments of a certain size to be fully compatible for district energy connection. Most recently, Council approved the Policy on Utility Rate Setting and Regulation which sets out the principles and methodology by which customer rates will be established and regulated by Council. The City's new City Hall and City Centre Library are already serviced by a new geo-exchange system. In addition, the City's district energy utility, Surrey City Energy, is preparing to begin construction of new thermal energy plants and associated distribution piping in order to provide thermal energy for the various developments currently planned and under construction in the City Centre.

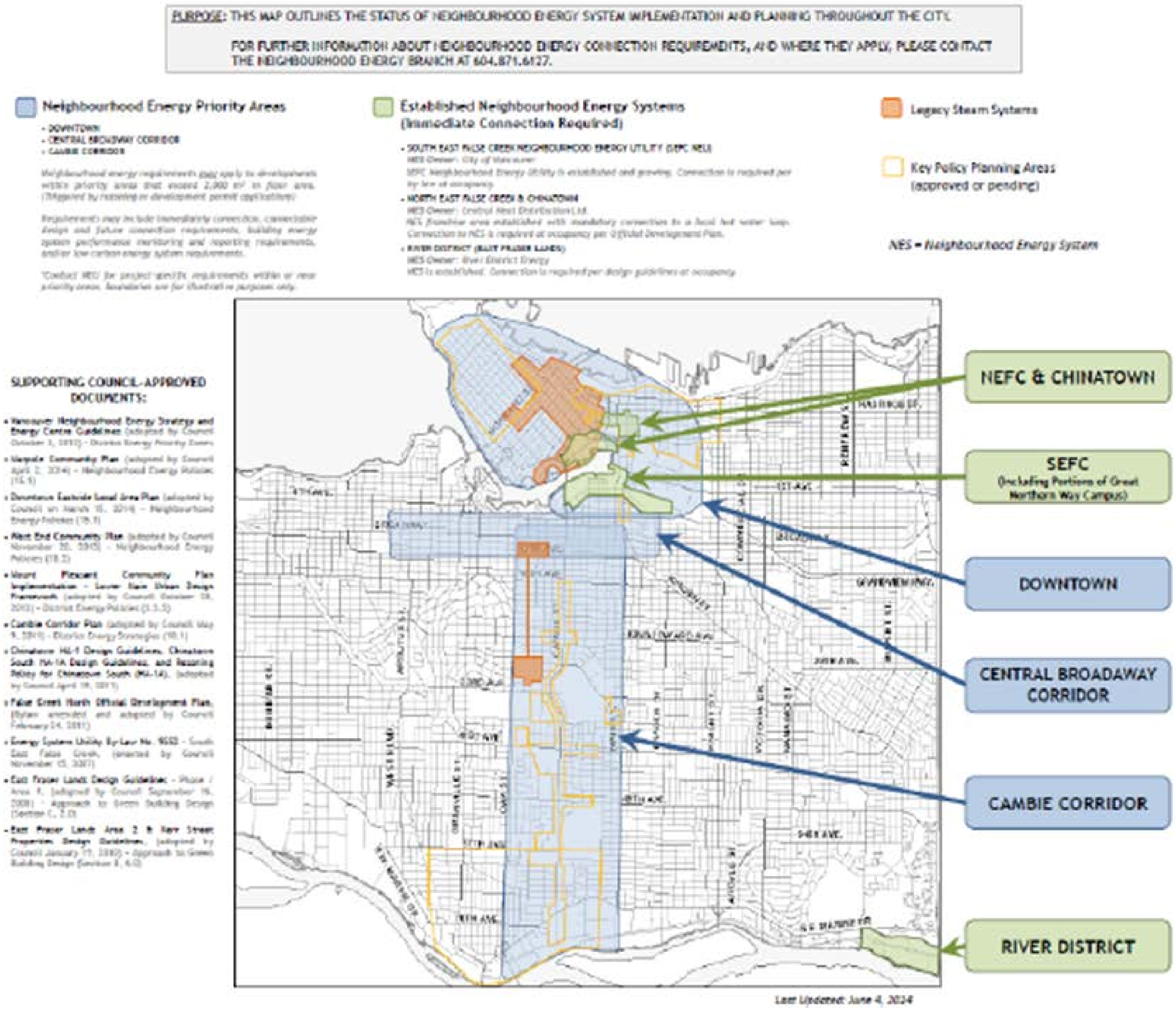
Similar programs can be found in most of the municipalities that have signed the Climate Action Charter. These actions by local governments promote moving away from natural gas (as the business as usual energy source) to other energy sources. They also encourage conservation and efficiency, which negatively impacts demand for natural gas (other things being equal).

The City of Vancouver's recent steps to endorse and promote the Creative Energy neighbourhood energy system in Northeast False Creek (NEFC) and Chinatown with an exclusive franchise for all space and water heating, backed by a mandatory connection bylaw, demonstrates an even greater willingness on the part of local governments to dictate energy choices.

The mandatory connection obligation for developers in the proposed Creative Energy franchise area and exclusivity over space and water heating for Creative Energy prevents FEI from competing for this future load in the proposed franchise area.

Moreover, the City of Vancouver has indicated that the Creative Energy application is only a small part of a broader Vancouver Neighbourhood Energy Strategy. The Strategy includes conversion of the "Downtown Steam System", for "South Downtown" and for "other Expansion Areas" which include the "West End" and "Downtown Eastside", "Cambie and Broadway Corridors".   The following map prepared by the City depicts the breadth of the potentially affected areas:

[54] http://www.richmond.ca/__shared/assets/_2_OCPAmendment_EnergyEfficiency39053.pdf.



FEI estimates that the Vancouver Neighbourhood Energy Strategy which includes NEFC and Chinatown, and other areas of Downtown, Central Broadway and Cambie Corridors currently represents an annual natural gas load of 10.5 PJ, which is approximately 5% of FEI's total annual load. This does not include any potential for load growth in these areas.

FEI does not have growth forecasts for these specific areas, or a forecast of the rate of redevelopment, so it is difficult to quantify the implications of the roll out of the Vancouver Neighbourhood Energy Strategy under a framework equivalent to that being proposed by Creative Energy. However, the delivery rate impact, other things being equal, associated with foregone load of 10.5 PJ would be a loss of revenue of approximately $32 million which equates to an increase of approximately 4.5% on natural gas delivery rates for the remaining FEI customers.[55]

(iii) ACTIVISM:

In recent years, environmentalist and anti-pipeline activists have increased pressure on companies involved in BC's pipeline and LNG projects. These movements seek to influence public policy and the actions of government bodies, and can impede infrastructure projects. The focus to date has been on oil and LNG infrastructure; however, activism of this nature poses an increasing risk for FEI, primarily because FEI is entering a phase of significant infrastructure development and renewal.

9.3 Carbon Tax

The carbon tax is an example of legislative or political action that has had direct implications for the price competitiveness of natural gas as an energy source in BC. The essential features of BC's carbon tax have remained consistent since the 2012 proceeding.

The following objectives are stated by the BC Government for implementation of carbon tax[56]:

- to encourage individuals, businesses, industry and others to use less fossil fuel and reduce their greenhouse gas emissions;
- to send a consistent price signal;
- to ensure those who produce emissions pay for them; and
- to make clean energy alternatives more attractive

As shown in Table 11, British Columbia and Quebec are the only two provinces in Canada that have implemented carbon tax policies on fossil fuels[57]; however, British Columbia has a significantly higher carbon tax rate than Quebec. The BC carbon tax tripled from $0.50 per GJ in 2008 to $1.49/GJ in 2012, where it has remained.

[55] Based on approved FEI January 1, 2015 delivery rates, consumption as depicted in Figure 9 above, and FEI's approved total non-bypass delivery margin for 2015.
[56] http://www.fin.gov.bc.ca/tbs/tp/climate/carbon_tax.htm.
[57] Quebec also has a cap and trade program and Ontario introduced its own cap and trade program in 2015.

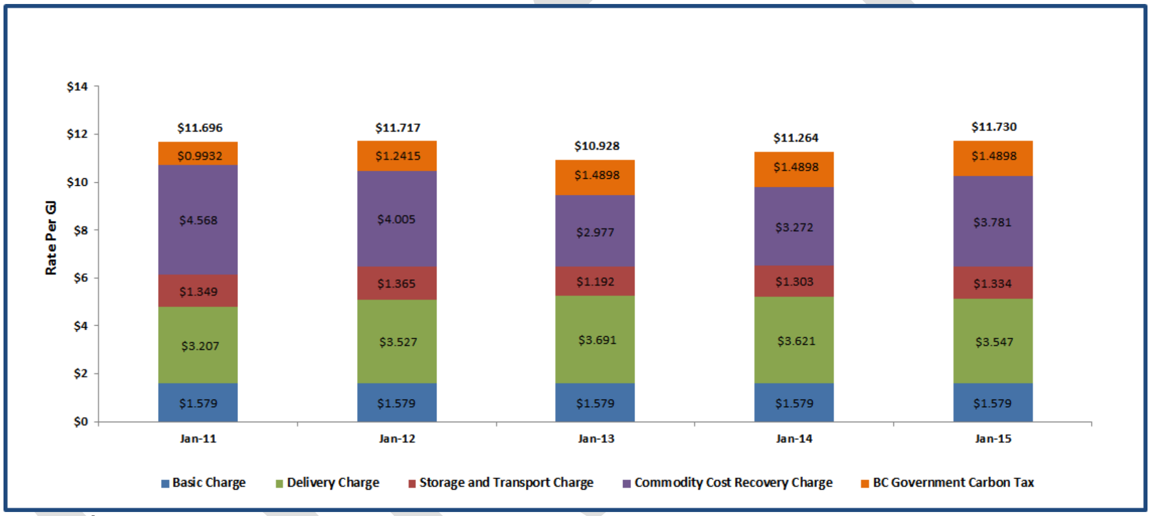
Table 11: Provincial Carbon Tax Rate

Province	Start Date	Carbon Tax Rate
British Columbia	2008	$10 per metric ton of CO2e emissions in 2008, increasing $5 annually to $30 in 2012
Quebec	2007	$3.50 per metric ton of CO2e emissions

Source: National Renewable Energy Laboratory

The carbon tax represents a competitive challenge for FEI as it is a discrete tax applicable to natural gas and other fossil fuels, but not to electricity (despite the fact that some of the electricity that is consumed in BC is generated by fossil fuels in neighboring jurisdictions). Figure 38 provides a historical look at gas prices from July 2010 to July 2014 for FEI Rate Schedule 1 customers in the Lower Mainland, which breaks out the carbon tax component.

Figure 38: FEI Lower Mainland Annual Residential Bill History (Rate Schedule 1)



Assumptions:
Natural gas use of 90 GJ
FortisBC Energy bill history includes all applicable rate riders
Effective January 1, 2015 the Mainland Service Area was created which includes the Lower Mainland, Inland, and Columbia Service Areas

Although no further carbon tax changes have been announced since the current rate took effect in 2012, the potential for carbon tax increases and the level of tax remain unknown at this time. The Government has stated that as other jurisdictions, especially within North America, introduce similar carbon taxes or carbon pricing, Government may again review and consider changes to the carbon tax. In the meantime, the competitive impacts of the carbon tax persist.

9.4 Aboriginal Rights and Title

FEI faces an elevated level of business risk related to relationships with First Nations in British Columbia relative to what existed at the time of the GCOC proceeding.

First Nations in British Columbia

Since FEI's activities span large parts of British Columbia, the Company comes in contact with a large number of aboriginal groups in British Columbia.

Aboriginal and treaty rights are expressly recognized and affirmed by section 35 of the Constitution Act, 1982. This poses risk to all utilities in Canada. However, two main factors differentiate BC from elsewhere:

1. First, there is a larger number of First Nations in BC compared to the rest of Canada. British Columbia recognizes 285 different First Nations, Bands and Tribal Councils, which is over one-third of all Aboriginal groups recognized in Canada.

2. Second, most First Nations in BC are not signatories or adherents to a treaty (historic or modern) and most land in British Columbia is not covered by a treaty, unlike in most other provinces. Treaties assist in delineating rights of the signatory First Nations. As a result, many First Nations in British Columbia hold outstanding claims to Aboriginal title and rights. In addition, there can be competing claims from different First Nations over the same piece of land, necessitating that utilities deal with multiple First Nations in respect of specific assets.

In contrast, all of the land in Ontario and Alberta is covered by treaties, as well as most of the land in Quebec. Each of those provinces recognizes far fewer aboriginal groups, most of which are signatories to treaties.

The area of aboriginal law is evolving and has potential implications for anyone proposing activities that may impact asserted Aboriginal rights or title, including FEI. Developments in case law have had, and may in the future have, a bearing on FEI's business by influencing Government policy and processes of permitting authorities.

The Crown has a constitutional duty to consult and, if appropriate, to accommodate unproven Aboriginal rights and title that are asserted by Aboriginal groups. In the majority of cases, the procedural aspects – that is, the actual on-the-ground work of information sharing, learning about the potential impacts and the planning for mitigation - is delegated to the project proponent. However, the duty rests ultimately with the Crown, and FEI is dependent on the Crown's level of commitment to fulfil its duty. The project proponent (FEI) is affected by the pace and nature of any dealings between the Crown and the First Nation, and any court decision that halts a project for lack of adequate consultation.

Aboriginal law issues are not new to FEI. FEI conducts its business in a manner influenced by, and in accordance with Aboriginal law. However, the recent SCC Decision in *Tsilhqot'in Nation v. British Columbia*, 2014 SCC 44 increases FEI's business risk. It has done so by creating some uncertainty through several passages.

The *Tsilhqot'in* decision of the SCC represents the first time that a Canadian court has determined that Aboriginal title exists in respect of a particular tract of land. This has particular relevance in British Columbia where most land is subject to title claims by Aboriginal groups.

Where Aboriginal title has been established, the Crown must not only comply with its constitutional consultation obligation but also ensure that the proposed government action is consistent with Aboriginal title. Governments can only infringe proven Aboriginal title with consent of the title holder or, by meeting the established test for "justification". Prior to the establishment of title, the obligation on the Crown remains to consult and potentially accommodate Aboriginal groups asserting title. However, the SCC created some uncertainty by also stating (at para. 92) "if the Crown begins a project without consent prior to Aboriginal title being established, it may be required to cancel the project upon establishment of the title if continuation of the project would be unjustifiably infringing". These comments from the SCC have been interpreted broadly by First Nations as applying to facilities and projects that are already constructed and in place on lands subject to a declaration of Aboriginal title. The intent of these passages will likely be the subject of future litigation and interpretation.

The uncertainty described above together with differing views on the scope of adequate consultation and accommodation creates operational and regulatory complexity in British Columbia and a risk of litigation that is greater than other areas in Canada, and greater than it was in 2012.

10. REGULATORY RISK

The degree to which FEI, as a regulated public utility, is dependent on the Commission for timely and fair approvals to earn its return on and of capital results in what FEI refers to in this section as regulatory risk. Although PBR has introduced additional risk in some respects, the broader regulatory constructs that supported FEI's characterization of regulatory risk in 2012 remain in place. FEI has thus assessed its overall regulatory risk as being similar to what it was in 2012 with the potential to be higher over the term of the PBR.

10.1 Uncertainty and Lag in Regulatory Approval

As a regulated public utility, FEI can only construct significant utility assets with a CPCN approval. It can only charge rates that have been approved by the Commission. The Commission sets the allowed return on equity and capital structure of the utility, and assesses depreciation rates that permit recovery of invested capital. The Commission, as a statutory entity, acts pursuant to its power under the *UCA* but within that framework has significant discretion in the exercise of those powers. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty. Regulatory oversight gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that does not provide FEI with an opportunity to earn its fair return on and of capital, or that necessary investments are not approved.

Regulatory Uncertainty

Regulatory uncertainty can be defined in different ways[58]. However for the sake of conciseness and for the purpose of this Application, FEI only considers the following three types of uncertainties:

1. Uncertainty raised due to the unpredictability of future decisions of the current regulator (and its successors) which may be exacerbated by regulatory inconsistency;
2. Uncertainty caused by vague decisions that are open to interpretation by the regulator (and its successors); and
3. Uncertainty regarding the future implications of the regulator's decisions.

The determinations regarding cost of capital have a direct and significant impact on FEI's ability to earn a return on and of its invested capital that meets the Fair Return Standard. In the GCOC Stage 1 Decision the Commission acknowledged that the "*BC regulatory framework has a significant influence on FEI's business and that individual decisions can have significant implications for FEI*.[59]"

The PBR Decision exemplifies how an individual Commission decision can have implications for FEI's ability to earn its fair return. Compared to cost of service regulation, performance-based rate-setting is subject to some additional risk associated with managing the controllable costs over a longer time horizon to a formulaic amount. This is particularly the case when the determined productivity improvement factor of the formula is higher than inflation and the expected industry productivity levels and therefore represents a risk to the balance between service quality, operating costs and capital costs under the PBR plan. In addition to this general risk inherent in all PBR plans, there are other specific aspects of the PBR Decision that have the potential to elevate regulatory risk for FEI during the PBR term:

- Reduction of FEI's growth factors by 50 percent: A major shift from previous PBR decisions in BC relates to the 50 percent reduction of growth factors in the PBR formulas. Considering that this is a new approach to PBR design in BC, the effect of this change may only be known after the PBR term. This is particularly important for the PBR formula related to capital expenditures for service line additions, where the relationship between service line additions and spending is relatively linear and therefore the growth factor reduction may be considered a form of cost disallowance of prudently incurred costs.

[58] For a comprehensive review of the definitions and taxonomy of regulatory risk please refer to the paper by Bastian Schwark titled "Influence of regulatory uncertainty on capacity investments – Are investments in new technologies a risk mitigation measure?", Retrieved from: http://infoscience.epfl.ch/record/153004/files/15d_schwark_paper.pdf.

[59] BCUC GCOC Stage-1 Decision, p.40.

- Potential disallowance of prudently incurred costs for exogenous events: The determination of the materiality threshold for exogenous events is another example of inconsistency between 2014 PBR Decision and FEI's extensive history with PBR design. As explained in responses to information requests and discussed during the oral hearing, a materiality limit gives rise to the potential for denial of prudently incurred costs and increases the underlying risk to the Companies.

- Backward-looking vs. forward-looking rate-setting elements of the PBR formula: Despite acknowledging some of FEI's reasoning for forecasting the formula drivers, the Commission determined that the inflation and growth factors of the PBR formula should be set based on backward looking historical data. This is analogous to cost of service regulation using a historical test year rather than a future test year. Forward test years have been a fundamental element of BC's regulatory framework and PBR formulas have always been determined based on forecast data. The Commission's decision to distance from this principle introduces some additional regulatory uncertainty.

- The PBR Decision replaced a number of important and long-standing deferral accounts with one more comprehensive deferral mechanisms that is only approved for the term of the PBR plan. This raises the prospect of how these costs will be treated when FEI emerges from PBR term.

Regulatory Lag

Regulatory lag is defined as a delay between incurring a cost and the implementation of the rates that recover these costs. The growing complexity of FEI's operating environment can also lead to delays (regulatory lag) in system investments, or the delivery of service offerings. Regulatory lag can present a risk for FEI's return on and of capital.

One aspect of regulatory lag is the time between application filings and final approvals. Given the complexity of the regulatory process, there is going to be an inherent delay between the time an application is filed and the final order related to that application. While the need to conduct regulatory reviews of utility operations is an integral part of being a public utility, the resulting delay does create risk for the utility. Risk arises in part because it is necessary for the utility to conduct its operations based on interim rates, with no assurance that the interim rate will be confirmed in the final decision, or that the projects contemplated and required to be undertaken will ultimately be approved.

Certain regulatory processes for FEI applications have recently been lengthy, resulting in extensive periods during which the utility is operating on interim rates. For instance, FEI's 2014 PBR application was filed in June 2013 while the Commission's Decision was released in mid-September 2014. However, overall regulatory lag is viewed as unchanged since 2012.

10.2 Deferral Accounts

Deferral accounts can help to reduce the rate impact and rate volatility for customers. The Commission determined in the 2009 ROE Decision that "…the effect of deferral accounts in reducing the risk of [FEI] as reducing the short-term, and not the long-term, business risk of [FEI]...".[60]

The majority of FEI's deferral accounts have been put in place to ensure forecast variances do not result in costs being inappropriately borne by customers or the Company. In the recent PBR Decision, the Commission directed FEI to discontinue the usage of a number of deferral accounts;[61] however, the discontinuance did not, in and of itself, materially change FEI's short-term risk profile since the Commission also directed FEI to true-up those costs each year through a flow-through mechanism[62] for the term of the PBR. The rest of key deferral accounts remained unchanged. The discontinuation of long-standing deferral accounts in favour of PBR specific mechanism has increased regulatory risk over the longer term because it is unknown how these costs will be addressed once FEI emerges from PBR. Table 12 summarizes the general categories of FEI's deferral accounts.

Table 12: Deferral Accounts

Deferral Account Category	General Purpose & Description
Margin Related	• Decreasing the volatility in rates caused by such factors as fluctuations in commodity prices and the significant impacts of weather on use rates • Deferring the cost of gas and delivery margin impacts arising from un-forecast variations in these types of factors and recovering them from/refunding them to customers over a longer period of time to reduce rate volatility <u>Examples:</u> Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (MCRA) and Revenue Stabilization Adjustment Mechanism (RSAM)
Energy Policy	• Capturing costs associated with changing energy policies that focus on energy efficiency, conservation and the environment • Deferring and amortizing these costs matches the costs of the programs with a reasonable period of time over which the benefits are expected to be realized by customers <u>Examples:</u> Energy Efficiency and Conservation Account (EEC), Compliance with Emissions Regulations, NGV Incentives

[60] Order No. G-158-09, page 19.

[61] Tax variance deferral account, the property tax variance deferral account, the insurance expense variance deferral account and the interest expense variance deferral account.

[62] The flow-through deferral account also include items such as interest expense related to changes in debt balances, customer variances for residential and commercial customers as well as the industrial margin variance.

Deferral Account Category	General Purpose & Description
Non-Controllable Items	• Items which are either outside of the Company's control or where the Company has limited ability to influence the costs • Deferring the variances from the forecast level of costs for these activities reduces the exposure for both the Utility and customers due to significant variances in these amounts, and serves to avoid windfall gains or losses to the Company or to customers <u>Examples:</u> Flow-through deferral account, Pension and OPEB Variances, BCUC Levies Variance
Costs of BCUC Applications	• Captures costs required to support regulatory applications, such as intervener and participant funding costs, Commission costs, costs for expert witnesses and consultants, costs related to independent validation of study results, legal fees, required public notifications, and miscellaneous other costs <u>Example:</u> 2014–2019 PBR Application Costs deferral account
Other	• Various accounts that provide benefits to customers and the Company, often for items that are non-recurring in nature <u>Examples:</u> Whistler Pipeline and Conversion Costs, BCOneCall Project, Gas Asset Records Project

10.3 Administrative Penalties

On May 31, 2012, Bill 30 – *Energy and Mines Statutes Amendment Act, 2012* – received Royal Assent. Bill 30 amends several statutes, including the *Clean Energy Act*, *Oil and Gas Activities Act* (*OGAA*) and *UCA*. In the GCOC proceeding, FEI had identified the new administrative penalties as a change in its regulatory environment since 2009. There has been no change in status of administrative penalty framework since its implementation. FEI also recognizes that administrative penalties can only be issued if FEI is found to have breached legislation or a Commission order. This discussion is included for the sake of completeness only, and FEI has not assessed any change in business risk associated with administrative penalties.