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November 22, 2013

Via Email
Original via Mail

Industrial Customers Group
c/o #301 – 2298 McBain Avenue
Vancouver, BC
V6L 3B1

Attention: Mr. Robert Hobbs

Dear Mr. Hobbs:

Re: FortisBC Inc. (FBC)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the Application)

Response to Industrial Customers Group (ICG) Information Request (IR) No. 2

On July 5, 2013, FBC filed the Application as referenced above. In accordance with Commission Order G-165-13 setting out the Amended Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to ICG IR No. 2.

FBC notes that the response to ICG IR No. 2, question 16.2 relates to the PBR Methodology, and will be submitted with the PBR Methodology IR responses.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

cc: Commission Secretary
Registered Parties (email only)

1.0 Reference: Exhibit B-15, ICG IR 1.5

"FBC has not filed a cost of service application for the 2014-2018 period. The forecasts included in Sections C4 and C5 for O&M Expense and Capital Expenditures, respectively, have been provided over the 5-year period for reference purposes only."

1.1 Please comment on whether or not based on the record of this proceeding FortisBC believes that the Commission will have an adequate record to establish rates following cost of service methodology for a one year test period effective January 1, 2014? If not, please file sufficient evidence so that the Commission can establish cost of service rates for a one year test period effective January 1, 2014 based on the evidence filed in this proceeding?

Response:

FBC does not consider all of the evidence on the record in this proceeding to be cost-of-service based. In particular, the O&M Expenses outlined in Section C5 are expressly said to be for reference purposes only and provide a high-level view of departmental cost drivers, challenges and opportunities. Nevertheless, given that the regulatory timetable in this proceeding is likely to yield a Commission decision in late June 2014, if the Commission declined to approve the PBR Plan, FBC would accept a one-year test period based on the currently forecast revenue requirements, rather than file new evidence at this stage, which would likely require yet more regulatory process.

2.0 Reference: Exhibit B-15, ICG IR 1.7 and B-1-6, page 59, and BCUC IR 1.181.3

"In other words, customers will benefit under the proposed PBR Plan since the resulting costs for customers under PBR are less than what FBC is forecasting they would likely be if rates were set under an indicative Cost of Service model using the O&M and capital forecast in Sections C4 and C5."

"The statement refers to the rate increases that would result from the PBR methodology compared to the rate increases using the indicative O&M and capital expenditures under a cost of service methodology, both without the rate smoothing impact of the RSDM."

"In addition, the RSDM has the effect of reducing the cumulative 2014-2018 rate impact because it reduces rate base in the early years."

2.1 Please explain the apparent difference between the above quoted comment that "resulting costs for customers under PBR are less than what FBC is forecasting they would likely be" under cost of service regulation, with the forecast of rates provided with Exhibit B1-15, ICG IR 1.7?

Response:

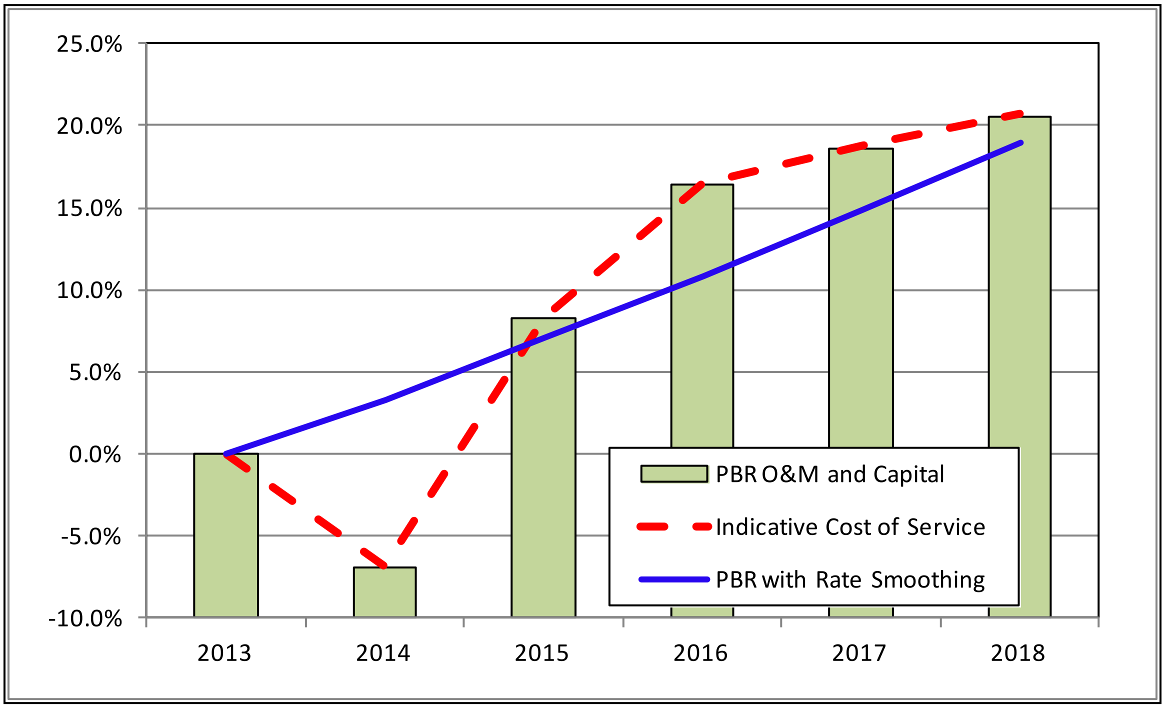
The apparent difference observed is due to timing of the Models used for analysis and minor variance in assumption sets. For the sake of clarity, the above referred analysis is restated below using "Evidentiary Update" filing data.

Additionally Figure B7-1 in Exhibit B-1, Page 75 is also reproduced below.

Analysis Parameters	Adjustments	Customer Rate Type	2014	2015	2016	2017	2018
			Customer Rate Impacts				
With Rate Smoothing:							
Evidentiary Update - As filed	With PBR	Yearly Rate	3.3%	3.6%	3.6%	3.6%	3.6%
		Cumulative Rate	3.3%	7.0%	10.9%	14.9%	**19.0%**
Evidentiary Update - Adjusted as:	Cost of Service	Yearly Rate	3.4%	3.6%	3.6%	3.7%	3.6%
		Cumulative Rate	3.4%	7.1%	11.0%	15.1%	**19.2%**
With No Rate Smoothing:							
Evidentiary Update - Adjusted as:	With PBR	Yearly Rate	-6.9%	16.3%	7.5%	1.9%	1.6%
		Cumulative Rate	-6.9%	8.3%	16.4%	18.6%	**20.5%**
Evidentiary Update - Adjusted as:	Cost of Service	Yearly Rate	-6.9%	16.4%	7.5%	2.0%	1.6%
		Cumulative Rate	-6.9%	8.4%	16.5%	18.8%	**20.7%**

Exhibit B-1, Figure B7-1 Reproduced with Evidentiary Update Data

Comparison of Rate Increase Scenarios



2.2 Please explain the comment "the RSDM has the effect of reducing the cumulative rate impact because it reduces rate base in the early years". In particular, please explain and identify the adjustments, if any, to rate base under the RSDM, and explain how the RSDM reduces rate base in the early years, and not in later years of the PBR Plan.

Response:

The RSDM account balances for the period 2014-2018 are shown in Section D4 at page 261 of the Application:

Table D4-2: RSDM Account Balances (Net of Tax) 2014 – 2018 ($ thousands)

	2014	2015	2016	2017	2018
Additions(Amortization)	24,375	(1,502)	(11,679)	(8,067)	(3,127)
Year End Balance	24,375	22,873	11,193	3,127	-

The balance in the RSDM is a credit (reduction) to rate base, which reduces financing costs and therefore revenue requirements. At the end of the 5-year period, the rate base reduction and the corresponding deferral account balance will be extinguished, making rate base equal to what it would be in the absence of the RDSDM.

2.3 Please comment on whether adjustments to rate base for CPCN projects would be delayed to the end of the test period under the RSDM? If so, please extend the table to include 2019 and show the rate impact expected in 2019 that is attributable to an adjustment to rate base for CPCN projects that are currently forecast?

Response:

No, rate base adjustments for CPCN projects will not be delayed to the end of the test period under the RDSM. Following approval of a CPCN, FBC will include in its revenue requirements (at the time of Annual Reviews) the forecast additions to plant in service as they enter rate base.

3.0 Reference: Exhibit B-15, ICG IR 1.8 and ICG IR 1.9

"FBC believes that the PBR Plan proposed in this Application, which promotes the continuation of FBC's productivity culture and provides for regulatory efficiency, is an important element of the Company's efforts to mitigate rate increases over the term of the proposed PBR Plan."

3.1 Please comment on whether FortisBC expects its rates to exceed BC Hydro rates during the 2014-2018 period?

<u>Response:</u>

FBC respectfully submits that comparisons of its rates to BC Hydro's are outside the scope of its Revenue Requirements Application. Regarding comparisons of FBC and BC Hydro rates, the Commission stated the following in its Decision on FBC's 2012-2013 Revenue Requirements Application, Order G-110-12:

"FortisBC operates with a different set of supply resources and with a different customer base in terms of geography, population density and the residential/commercial/industrial mix it faces. The Commission Panel has no mandate, nor does it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro. The Commission Panel believes that FortisBC's responsibility is to provide safe and reliable service in a cost-effective manner consistent with British Columbia's energy objectives. To do so, FortisBC must design and manage its system based on the resources available to it and the needs of its customers. This, at times, may result in rates that are greater than those of BC Hydro and potentially times when they are less." (Order G-110-12, pages 20 and 21)

3.2 Please resubmit FortisBC's response to ICG IR 3.2, contained in Exhibit B-8 in the proceeding for the FortisBC Inc. Application for a Certificate of Public Convenience and Necessity for the Purchase of the Utility Assets of the City of Kelowna as a working spreadsheet, and updated for FortisBC's proposed rates for the period for 2014 through 2018, and correcting for any errors in the original submission. Please also omit the comparable City of Kelowna rates.

<u>Response:</u>

The Commission has previously determined that a direct comparison of FBC and BC Hydro Rates are not appropriate. In the Reasons accompanying Order G-110-12 in the matter of An

Application by FortisBC Inc. for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan, the Commission said at page 20:

> *FortisBC operates with a different set of supply resources and with a different customer base in terms of geography, population density and the residential/commercial/industrial mix it faces. The Commission Panel has no mandate, nor does it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro. The Commission Panel believes that FortisBC's responsibility is to provide safe and reliable service in a cost-effective manner consistent with British Columbia's energy objectives. To do so, FortisBC must design and manage its system based on the resources available to it and the needs of its customers. This, at times, may result in rates that are greater than those of BC Hydro and potentially times when they are less.*

The Company therefore declines to provide a response as in the rate comparison in not determinative of whether the particular rate proposed by FBC is appropriate given the resources available to it and the needs of its customers.

4.0 Reference: Exhibit B-15, ICG IR 6.1

TFP Rates

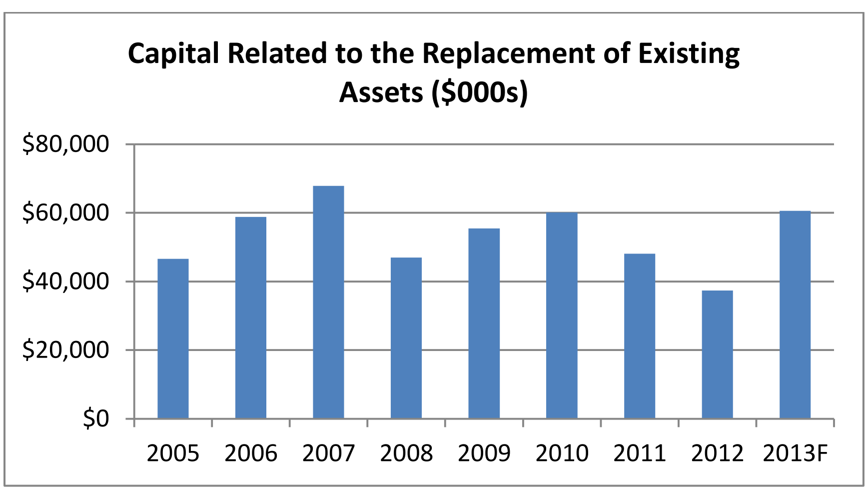
"B&V concludes that the downward trend of TFP growth is mainly caused by capital intensive infrastructure replacement programs in both natural gas and electric utilities, which drive up input costs without increasing output. B&V expects that this trend will continue during FBC's proposed five year PBR term."

4.1 Please provide a graph and table showing the amount of capital that has been expended since 2005 for replacement of existing assets, and the similar forecast for 2014 to 2018. Please specifically identify each capital expenditure over $1 million that is not included in the category of "replacement of existing assets".

Response:

The following table and graph provide an estimate of the approximate amount of capital (including overheads and AFUDC, excluding costs of removal) that has been expended during the 2005 – 2013 period for the replacement of existing assets. FBC estimates that approximately 47 percent of overall capital expenditures for 2005 – 2013 period are related to the replacement of existing assets.

	Estimated Capital Related to the Replacement of Existing Assets ($000s)								
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013F**
Generation	13,225	13,174	20,275	15,609	18,818	17,575	16,667	7,597	3,072
Transmission and Stations	14,701	25,250	26,703	14,728	16,274	23,294	11,427	14,514	23,681
Distribution	12,976	12,328	10,417	8,474	12,517	12,605	8,359	8,913	14,401
General Plant	5,713	8,107	10,416	8,136	7,885	6,689	11,653	6,321	19,395
Total	**46,614**	**58,859**	**67,812**	**46,947**	**55,494**	**60,163**	**48,106**	**37,346**	**60,549**



1 The table below specifically identifies each capital expenditure over $1 million that is not
2 included in the category of "replacement of existing assets" for 2005 – 2013.

3 **Capital projects over $1 million not related to the replacement of existing assets**

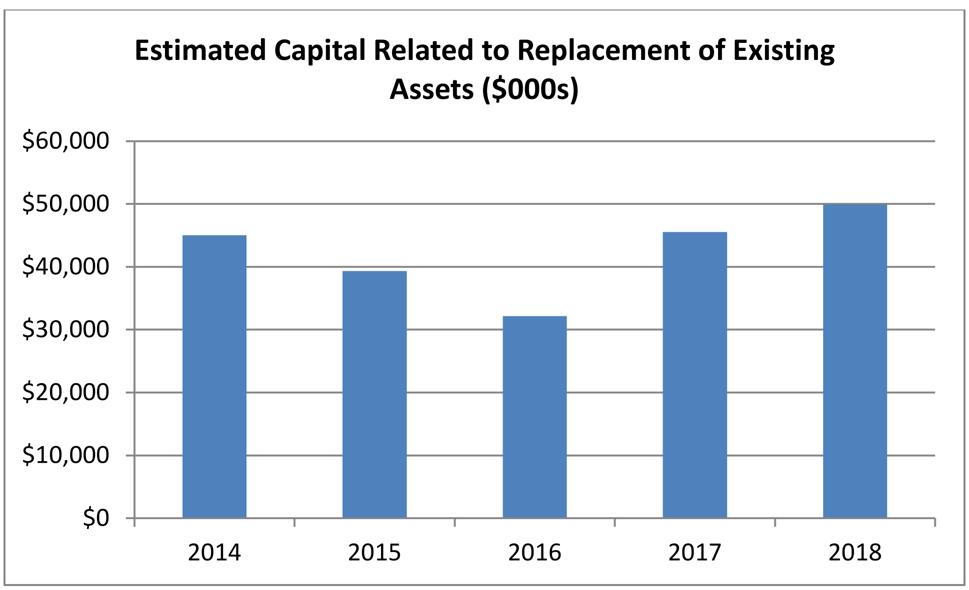
2005
Transmission and Stations
Vaseux Lake Terminal
Kelowna Area Upgrade
Big White Transmission and Substation
Waterford Upgrade
Distribution
Distribution Growth
Customer New Connects
General Plant
Information Systems
2006
Transmission and Stations
Vaseux Lake Terminal
Kelowna Area Upgrade
Big White Transmission and Substation
Ellison Distribution Source
Nk'Mip Substation
Ymir Upgrade
Lambert Transformer 2
Distribution
Customer New Connects
Creston Distribution Related to Lambert
DGB2-OKM3 Tie
Distribution Growth
General Plant
Information Systems

2007
Transmission and Stations
Okanagan Transmission Reinforcement
Big White Transmission and Substation
Ellison Distribution Source
Nk'Mip Substation
Lambert Transformer 2
Crawford Bay Capacitor
Distribution
Customer New Connects
Distribution Growth
General Plant
Information Systems
2008
Transmission and Stations
Okanagan Transmission Reinforcement
Big White Transmission and Substation
Ellison Distribution Source Substation
Black Mountain Distribution Source Substation
Ootischenia Substation
18 L Breaker - Waneta
Distribution
Customer New Connects
Distribution Growth
General Plant
Information Systems
2009
Transmission and Stations
Okanagan Transmission Reinforcement
Benvoulin Substation
Ellison Distribution Source
Black Mountain Distribution Source
Distribution
Customer New Connects
Distribution Growth
General Plant
Information Systems

2010
Transmission and Stations
Okanagan Transmission Reinforcement
Benvoulin Substation
Recreation Capacity Increase
30 Line Conversion
Distribution
Customer New Connects
Distribution Growth
General Plant
Distribution Substation Automation
Information Systems
2011
Transmission and Stations
Okanagan Transmission Reinforcement
Huth Bus Reconfiguration
Distribution
Customer New Connects
Distribution Growth
General Plant
Distribution Station Automation
Information Systems
2012
Transmission and Stations
Okanagan Transmission Reinforcement
Huth Bus Reconfiguration
Distribution
Customer New Connects
Distribution Growth
General Plant
Information Systems
2013F
Transmission and Stations
Ellison Sexsmith Transmission Tie
Distribution
COK Acquisition
Customer New Connects
Distribution Growth
General Plant
Advanced Metering Infrastructure
Information Systems

The following table and graph provide an estimate of the approximate amount of forecast capital (excluding overheads and AFUDC and including costs of removal) for the 2014 – 2018 period for the replacement of existing assets. The forecast capital expenditures are based on the five year capital forecast as discussed in Section C5 of the Application (Exhibit B-1), and not the capital expenditures as determined by the PBR formula. The forecast capital expenditures include expenditures related to Major Projects (including future CPCN applications) for the 2014 – 2018 period. FBC estimates that approximately 54 percent of the total forecast capital expenditures for the 2014 – 2018 period are related to the replacement of existing assets.

	Estimated Capital Related to the Replacement of Existing Assets ($000s)				
	2014	**2015**	**2016**	**2017**	**2018**
Generation	2,997	2,793	6,352	16,748	10,832
Transmission & Stations	13,442	7,068	6,101	10,642	20,326
Distribution	11,910	11,869	13,142	13,259	13,873
General Plant	16,706	17,604	6,586	4,912	4,871
Total	**45,055**	**39,334**	**32,180**	**45,562**	**49,903**



The table below specifically identifies each capital expenditure over $1 million that is not included in the category of “replacement of existing assets” for 2014 – 2018.

Capital projects over $1 million not related to the replacement of existing assets

Project Name
2014
Transmission and Stations
Grand Forks to Warfield Fibre Installation
Huth Second Distribution Transformer Addition
Distribution
Distribution Growth
Customer New Connects
General Plant
Information Systems
Business Technology Transformation
Advanced Metering Infrastructure
2015
Transmission and Stations
Huth Second Distribution Transformer Addition
Distribution
Distribution Growth
Customer New Connects
General Plant
Information Systems
Business Technology Transformation
Advanced Metering Infrastructure
2016
Distribution
Distribution Growth
Customer New Connects
General Plant
Information Systems
Business Technology Transformation
Okanagan Long Term Solution

Project Name
2017
Transmission and Stations
Kelowna Bulk Transformer Capacity Addition
Grand Forks Transformer Addition - Option 1 - Single Breaker
Distribution
Distribution Growth
Customer New Connects
Grand Forks Terminal Feeder Addition
General Plant
Information Systems
Business Technology Transformation
2018
Transmission and Stations
Kelowna Bulk Transformer Capacity Addition
Grand Forks Transformer Addition - Option 1 - Single Breaker
New Central Okanagan Station
Distribution
Distribution Growth
Customer New Connects
DG Bell Feeder 4 Addition
General Plant
Information Systems
Business Technology Transformation

5.0 Reference: Exhibit B-15, ICG 9.2

Forecast 2013 Capital Expenditures

"Recognizing that the Capital Expenditure Base for the 2014-2018 formula should be a Capital Expenditure number which has undergone a full review through an oral public hearing, FBC has used the 2013 Approved capital expenditures for 2013 from the 2012-2013 RRA Decision as the starting point for the capital formula ($101.970 million) which becomes $49.18 million when adjusted as detailed in Table C5-2."

5.1 If the PBR application proposed by FortisBC is not approved, will FortisBC support a full review through an oral public hearing of the capital expenditures for 2014 and beyond, and if not, why not?

<u>Response:</u>

Given that FBC has just undergone a full Cost of Service revenue requirement, which included an oral hearing to review the forecast capital expenditures for the 2012-2013 test period, as well as the 20 year forecast (30 years in the case of bulk transmission projects) capital expenditures as detailed in the 2012 Long Term Capital Plan, the Company does not believe such a review is necessary, nor efficient.

6.0 Reference: Exhibit B-15, ICG 9.2 and B-1-6, page 4

Forecast 2013 Capital Expenditures

"Currently, FBC is projecting to underspend 2012/13 capital expenditures as compared to approved capital expenditures.

6.1 Please reconcile the statement from Exhibit B-1-6 with the significantly greater forecast capital expenditures in 2013 as compared to the approved amount as shown in the response to ICG 9.2.

<u>Response:</u>

The response to ICG IR 1.9.2 was based on the forecasts available at the time of the filing of the Application (July 5, 2013), and included forecast expenditures of $37.766 million related to the CoK Acquisition. As detailed in Exhibit B-1-6, the 2013 Forecast has been updated from $138.694 million to $94.368 million, as compared to 2013 Approved of $109.851 million (which does not include the impact of the CoK acquisition).

7.0 Reference: Exhibit B-15, ICG IR 9.3

"The analysis provided in the response to ICG IR 1.9.1 excludes Major Projects from the formula calculation. The Major Projects are highlighted in the following table."

7.1 Please confirm that the Major Projects highlighted in the table attached to ICG IR 9.3 are all projects that will be the subject of a CPCN Application either under both cost of service and PBR regulation? If not confirmed, please identify the projects that will not be the subject of a CPCN Application?

Response:

With the exception of projects already approved, FBC confirms that the Major Projects highlighted in the table provided in response to ICG IR 1.9.3 are projects for which FBC intends to submit a CPCN application under either cost of service or PBR regulation.

8.0 Reference: Exhibit B-15, ICG 12.2

Reliability Indicators

8.1 Please discuss whether the significant improvements in SAIDI and SAIFI now suggest that sustaining capital may be reduced.

Response:

Sustainment capital expenditures are needed to maintain safe and reliable service to customers. The improvements in SAIDI and SAIFI were primarily due to significant growth capital upgrades completed by FBC over the past 10 years; this does not imply that sustainment capital could be reduced without negative impacts on reliability.

9.0 Reference: Exhibit B-15, ICG IR 18.1

Load growth

Exhibit B-1-6, Revised Table C2-3

Exhibit B-1-6, Revised ICG IR 21.1

9.1 Please reconcile the 2013 load forecast provided in the response to ICG IR 18.1 with the updated actuals and forecasts provided in the revised Table C2-3 and the revised response to ICG IR 21.1.

Response:

The 2013 load forecast provided in the response to ICG IR 1.18.1 is the forecast for 2013 used to develop the 2014 and forward forecast. As such it does not contain any actual loads for 2013. The forecast in revised Table C2-3 includes actual loads through April for 2013 and so is a different number.

The 2013 Gross load forecast was not changed as part of the evidentiary update and therefore the variances between the monthly forecast and actual load that are part of the revised response to ICG IR 1.21.1 are not reflected in the revised Table C2-3.

10.0 Reference: Exhibit B-15, ICG IR 19.1

PPE Variance Sharing

10.1 It is apparent that FortisBC has been significantly over-estimating power purchase costs since 2010. Assuming no rate smoothing is in effect, how much of the rate decrease in 2014 as compared to 2013 rates is attributable to the reduced power purchase expense? Please provide the numerical analysis to support the response.

Response:

The Company objects to the characterization that it over-estimates power purchase costs. The Company estimates such costs on a prudent basis, but has been successful in achieving savings from those costs for the benefit of customers. FBC has been estimating power purchase costs by assuming firm resources for expected customer loads and submits that it is appropriate to do so. However, the Company has, in some instances been able to take advantage of depressed energy markets and reduce its expected power purchase costs. For 2012 and 2013 all such variances were approved to flow through directly to customers. For 2014 and the remaining term of the proposed PBR, the Company has also requested that any variances between approved and actual power purchase expense are deferred and flow back to customers.

Assuming no rate smoothing, the impact on 2014 rates of the 2012-2013 Power Purchase Expense variances calculation has been provided below.

The rate decrease as indicated below would be 4.8 percent.

Power Purchase Expense variance 2012 (including water fees)	8,438	**A**
Power Purchase Expense variance 2013 (including water fees)	6,643	**B**
Total Power Purchase Expense variance 2012 & 2013 (including water fees)	**15,081**	**C = A+B**
2014 Revenue at prior year Rates	312,924	**D**
Rate decrement in 2014 due to 2012-13 Power Supply cost variance	**4.8%**	**100% x (C/D)**

Note: All cost data are in "Thousands"

11.0 Reference: Exhibit B-15, ICG IR 20.2

Power Purchase Expense

"FBC would have locked in market savings prior to the beginning of the year, consistent with what FBC has actually done for the first year of the New PPA, and what FBC has included in this Application. This would have resulted in a similar level of BC Hydro volume displacement as was actually achieved in 2012 and projected for 2013. It is not possible to state what cost impact, if any, there would have been but as discussed in the application at Section C, page 99, FBC has taken a more balanced approach for 2014 that reduces forecasted power purchase expense to more closely match expected PPA and market purchases."

11.1 Please provide the price, quantity, duration, delivery point and other contract details of the market transactions that FortisBC has "locked in".

Response:

Please refer to the response to BCUC IR 1.86.1. As discussed in that response, the details of the market transactions that FBC has "locked in" are confidential due to commercial sensitivity. FBC can confirm, however, that the updated PPE forecast provided as part of its Evidentiary Update filed on October 18, 2013 includes the impact of the finalized agreements among other items.

11.2 Please explain in detail FortisBC "more balanced approach" taken in 2014, and explain why this approach was not employed years earlier, especially given the over-estimating that has occurred since 2010? Please also explain why FortisBC resisted using a "more balanced approach" during the 2011 Revenue Requirements proceedings when urged to do so by Intervenors.

Response:

Please refer to the discussion in Section 2.4 of the Application (Exhibit B-1, pages 99-100).

12.0 Reference: Exhibit B-15, ICG IR 25.1

Other Income

12.1 Please explain the reasons for the large decrease in 2013 "Apparatus and Facilities Rental" revenues as compared to 2012.

<u>Response:</u>

The decrease from 2012 Actual to 2013 Projected is a result of 2012 Actual being higher than expected due to non-routine revenues.

As discussed in Section C3, Part 3.2 of the 2014-2018 RRA, annual billing is completed mid-year and updated annually to include changes to the rate or number of pole contacts, which is then captured in the following year's billing. The annual true-up to 2011 for one of the service providers was completed in early 2012 and included an approximate 25 percent increase in the final rate. This increase translated to an approximate $0.6 million true-up to 2011, which was subsequently invoiced and recognized as other income in mid-2012.

The rate for this service provider includes a financing and tax cost component, a maintenance cost component, and an administrative cost component. The reason for the increase to the 2011 final rate is due to Order G-195-10 which approved the 2011 Capital Expenditure Plan, but disallowed certain sustaining capital requests and resulted in those costs being included in O&M expense. As a result the maintenance cost component for this service provider increased more than expected and impacted the final rate for 2011. The rates used for determining the forecast pole rental revenue has considered these changes for 2013 and the 2014-2018 PBR period.

13.0 Reference: Exhibit B-15, ICG IR 27.1

Energy Supply

13.1 In the 2012-2013 revenue requirements Decision, the Commission Panel directed FortisBC as follows:

> "The Commission Panel agrees with BCMEU and because FortisBC has not sufficiently justified the need for an additional FTE, denies the additional FTE and related costs of $142,000 in each of 2012 and 2013." and,
>
> "Accordingly, the Commission Panel directs FortisBC to continue to maintain PPME as part of O&M expenses."

Please explain whether the "Energy Supply" category in the response to ICG IR 27.1 contains any costs that were associated with the PPME category in the 2012-2013 Revenue Requirements Application and whether it includes any additional FTE's between 2012 and 2018.

<u>**Response:**</u>

Costs associated with PPME work are included as part of Energy Supply O&M in the table shown in the response to ICG IR 1.27.1.

As shown in the organization charts for Energy Supply (Electric) provided as part of the response to BCUC IR 1.123.2, no additional FTE was hired during 2012-2013, in compliance with the Decision on the 2012-2013 Revenue Requirements Application. Although the 2012-2013 PPME work was managed using existing resources, additional resources commencing 2014 will be essential to enable FBC to manage the work with the increased complexities under the new agreements.

14.0 Reference: Exhibit B-15, ICG IR 29.1

Unit Maintenance

14.1 Please confirm that prior to the upgrade and life extension program, major maintenance on the generating units was performed once every 20 years.

Response:

Prior to the upgrade and life extension program the 10 year major electrical inspections/maintenance and the 20 year major mechanical inspections/maintenance was the norm.

14.2 For each generating unit upgrade and/or life extension which was supported by a CPCN application, please provide any reference from the application to the maintenance cycle that existed prior to the project or could be expected after the completion of the project.

Response:

Although the CPCN applications for the ULE projects did not explicitly discuss the maintenance cycle that existed prior to the project or that could be expected after completion of the project, an avoided O&M cost of $100 thousand for the year of implementation and the year immediately following was recognized as a result of avoided maintenance and inspection outages related to the upgraded unit(s).

As indicated in the submission, page 122, paragraph 1, “With the completion of the ULE program, the Company will return to its full maintenance program at the facilities comprised of both routine (1 to 2 year intervals) and non-routine (3, 5, 10, 15 year intervals) tasks. This program will be guided by a condition-based philosophy rather than a time-based interval philosophy.”

15.0 Reference: Exhibit B-15, ICG IR 33.3

MRS Costs

"Labour costs include incremental MRS related costs from other departments. FTEs working on MRS tasks have varying degrees of involvement. The compliance effort in 2011 for Operating was approximately 12,000 operating hours and in 2012 was approximately 15,000 operating hours."

Exhibit B-1, Section C4.13.4, page 156

Environment, Health and Safety O&M

"A vacancy in the department was filled in late 2010, and an additional resource was retained in 2011 in order to review new security requirements related to the management of the BC MRS standards, in addition to metal theft concerns which have increased significantly."

15.1 Please confirm whether the table of MRS costs provided in the response to ICG IR 33.3 includes the costs from the EH&S department referenced in the application. If not confirmed, please identify all other incremental costs associated with MRS.

Response:

Confirmed.

15.2 Please explain why the 2012 MRS costs provided in the response to ICG IR 33.3 are more than double the estimate provided in the original assessment report and have increased by more than 40 percent over 2011.

Response:

The initial evaluation did not contemplate the level of routine audits, the rules of procedure established, WECC as the administrator, and the level of magnitude required to establish and maintain auditable compliance as required by the MRS. Since BCUC order G-67-09 (adoption of 103 standards and the February 12, 2008 NERC Glossary of Terms), the BCUC (through orders G-167-10, G-151-11, G-162-11, G-175-11,R-17-12, R-1-13 and R-11-13) has adopted 11 new standards, 7 replacement standards, 62 revised standards (11 of which were two revisions at once), the August 4, 2011 NERC Glossary of Terms and modification of the Rules of Procedure. Pending approval are 9 revised standards and the December 5, 2012 NERC Glossary of Terms.

FBC's MRS effort is a combination of increased tasks associated with ensuring compliance to the auditable level required as well as a more comprehensive understanding of ensuring compliance. Information obtained from consultants further informs FBC's understanding of the magnitude of effort required to maintain compliance.

With respect to historical expenditures, it should be noted that MRS-related activities in 2009 and 2010 included both Capital and Operating components, but since 2010, are increasingly operational in nature. The compliance effort in 2011 for Operating was approximately 12,000 hours. Expenditures for 2012 were primarily for Operating effort, with 22 requirements remaining in mitigation. The Operating hours in 2012 were approximately 15,000. In contrast, 2013 will be the first year in which a majority of the requirements will be out of mitigation and require full and ongoing compliance. Based on acquired experience, the changing standards and processes, the audit results, and the knowledge obtained from user group participation, FBC forecasts approximately 20,000 hours of internal labour effort to ensure compliance is maintained going forward, subject to further changes in standards or the BC MRS program.

16.0 Reference: Exhibit B-15, ICG IR 39.1

New Connects

16.1 Please explain why the "New Connects" expenditures forecasts for 2014 through 2018 are so much lower than any Approved or Actual amount since 2007.

Response:

The forecast expenditures for this project are based on a three-year rolling average adjusted for anomalous years, projected customer growth and inflation.

Also, as stated on the note of the table on page 71 of Exhibit B-15, the forecast expenditures for 2014-2018 do not include loadings and AFUDC. The actual expenditures from 2007 to 2013 include loadings.

16.2 Please explain what effect greater-than-forecast "New Connects" actual expenditures in the years 2014 through 2018 would have in a PBR environment. Please explain what effect under forecasting the "New Connects" capital expenditures has on FortisBC's ability to increase capital expenditure forecasts in other areas.

Response:

This IR has been identified as relating to the PBR Methodology and will be submitted with the PBR Methodology IR responses.

17.0 Reference: Exhibit B-15, ICG IR 42.1

Capitalized Overhead

17.1 Please compare FortisBC's policy and approach to the capitalized overhead rate with that of Ontario Hydro as described in the document found at the following location:
http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2012-0031/Exhibit%20C/C1-07-02.pdf

Response:

Although there is no commonly accepted overhead capitalization methodology, a comparison of Hydro One's and FBC's capitalization policy as a percentage of Gross O&M, allocation methodologies and criteria illustrate that both approaches are similar in nature. The Company believes that 20 percent of Gross O&M is the appropriate methodology for calculating capitalized overhead.

As part of the requested comparison, FBC has taken capitalized overhead dollars calculated for 2014 over 2014 Base Capital Expenditures to derive a resulting capitalization overhead rate of 12 percent. Please also refer to the response to BCUC IR 2.50.1. The Company is unable to determine whether the approaches differ with respect to the definition of Capital Expenditures. The Company has calculated FBC's 2014 Capitalization Rate as a percentage of Base Capital Expenditures excluding larger CPCN projects (such as those described in Exhibit B-1, Section C5.7, Page 226). The following table provides the comparison.

Element	FBC	Hydro One
2014 Capitalization Rate as a percentage of **Gross O&M**	20%	20%
2014 Capitalization Rate as a percentage of **Capital Expenditure**	12%	9%
Allocation Methodology	• Range of overhead rates determined by a Survey model and a Mathematical model (somewhat similar to the Hydro One Labour content ratio approach).	• Some shared services allocated based a 2011 Time Study • Balance of shared services overhead rate calculated as an equal blend of a Labour content ratio (ratio of O&M to Capital) and a Total Spending ratio (ratio of total O&M to total Capital)

Element	FBC	Hydro One
Allocation Criteria	• Cost Causality - a direct correlation to the cost of the services • Objective Results - an objective allocation amount that is free from undue bias • Cost Effectiveness - the allocation driver is calculated and maintained from readily available information resulting in minimal time and expense. • Stability Over Time - the allocation methodology can accommodate changes to the allocation driver over time and is scalable. • Transparent and Supportable Methodology - the driver used and the source or basis on how it is determined is visible to all parties affected. The allocation approach is supported by a defined and documented methodology, model and other supporting documentation. • Regulatory Precedence - the cost allocation methodology has been tested and approved through previous regulatory reviews. • Distinguishable from Directly Allocated Capital Costs -the overhead costs must be distinguished from those that are directly charged to capital. • Accuracy of Underlying Data - any data used in the methodology should be accurate and able to be relied upon. The data should provide an appropriate measure of the underlying volume of activity or output. • Flexibility/Adaptability - the methodology should be able to accommodate future changes in regulatory, accounting and organizational changes with reasonable ease.	• Cost Causation – there is a causal relationship between the basis used to allocate costs and the costs incurred. • Benefits Received – if cost causation cannot be determined then allocate the cost based on benefits received • The method should be based on data that can be obtained at a reasonable cost and is verifiable over time • If estimates are used they should be unbiased and consistent with results that would be obtained from actual data.

18.0 Reference: Exhibit B-15, ICG IR 44.1

Capitalized Overhead

18.1 Please expand the table provided in the response to ICG IR 44.1 to include the amount of capital in each category and year prior to the addition of any of the overhead amounts.

Response:

		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Approved	
		($000s)	% of Total	Actual	% of Total	Actual	% of Total	Actual	% of Total	Actual	% of Total	Actual	% of Total	Approved	% of Total
Generation	Growth	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
	Sustaining	18,726	14.8%	14,443	15.3%	17,480	18.5%	16,671	13.6%	15,040	21.2%	6,489	13.3%	2,243	2.3%
		18,726	14.8%	14,443	15.3%	17,480	18.5%	16,671	13.6%	15,040	21.2%	6,489	13.3%	2,243	2.3%
Transmission and Stations	Growth	53,671	42.5%	32,201	34.1%	35,351	37.3%	63,229	51.6%	14,635	20.6%	3,962	8.1%	3,184	3.2%
	Sustaining	6,038	4.8%	6,898	7.3%	5,661	6.0%	5,606	4.6%	5,905	8.3%	9,696	19.9%	15,378	15.6%
		59,709	47.3%	39,099	41.3%	41,012	43.3%	68,834	56.1%	20,541	29.0%	13,659	28.1%	18,562	18.8%
Distribution	Growth	18,948	15.0%	20,343	21.5%	12,991	13.7%	13,594	11.1%	13,861	19.5%	12,328	25.3%	18,309	18.6%
	Sustaining	14,323	11.4%	10,039	10.6%	12,280	13.0%	13,114	10.7%	6,410	9.0%	6,433	13.2%	8,518	8.6%
		33,271	26.4%	30,383	32.1%	25,271	26.7%	26,708	21.8%	20,271	28.6%	18,761	38.5%	26,828	27.2%
General Plant		14,484	11.5%	10,640	11.3%	10,903	11.5%	10,407	8.5%	15,090	21.3%	9,772	20.1%	50,993	51.7%
Unloaded Gross Capital Expenditure (Net of Cost of Removal)		**126,190**	**100.0%**	**94,564**	**100.0%**	**94,666**	**100.0%**	**122,619**	**100.0%**	**70,941**	**100.0%**	**48,681**	**100.0%**	**98,626**	**100.0%**

		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Approved	
		($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total
Direct Overhead															
Generation	Growth	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
	Sustaining	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
		-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Transmission and Stations	Growth	3,306	2.6%	2,291	2.4%	2,938	3.1%	3,413	2.8%	1,726	2.4%	555	1.1%	328	0.3%
	Sustaining	372	0.3%	491	0.5%	470	0.5%	303	0.2%	697	1.0%	1,358	2.8%	1,582	1.6%
		3,678	2.9%	2,782	2.9%	3,408	3.6%	3,715	3.0%	2,423	3.4%	1,913	3.9%	1,910	1.9%
Distribution	Growth	1,167	0.9%	1,448	1.5%	1,079	1.1%	734	0.6%	1,635	2.3%	1,727	3.5%	1,884	1.9%
	Sustaining	882	0.7%	714	0.8%	1,020	1.1%	708	0.6%	756	1.1%	901	1.9%	876	0.9%
		2,049	1.6%	2,162	2.3%	2,100	2.2%	1,442	1.2%	2,391	3.4%	2,628	5.4%	2,760	2.8%
General Plant		-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Total Direct Overhead		**5,727**	**4.5%**	**4,944**	**5.2%**	**5,508**	**5.8%**	**5,157**	**4.2%**	**4,814**	**6.8%**	**4,541**	**9.3%**	**4,670**	**4.7%**

		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Approved	
		($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total
Capitalized Overhead															
Generation	Growth	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
	Sustaining	1,254	1.0%	1,315	1.3%	1,625	1.6%	1,243	1.0%	2,140	2.8%	1,337	2.5%	250	0.2%
		1,254	1.0%	1,315	1.3%	1,625	1.6%	1,243	1.0%	2,140	2.8%	1,337	2.5%	250	0.2%
Transmission and Stations	Growth	3,816	2.9%	3,141	3.2%	3,560	3.6%	4,970	3.9%	2,328	3.1%	931	1.7%	392	0.4%
	Sustaining	429	0.3%	673	0.7%	570	0.6%	441	0.3%	939	1.2%	2,278	4.3%	1,892	1.8%
		4,246	3.2%	3,814	3.8%	4,131	4.1%	5,410	4.2%	3,267	4.3%	3,209	6.0%	2,284	2.2%
Distribution	Growth	1,347	1.0%	1,984	2.0%	1,308	1.3%	1,068	0.8%	2,204	2.9%	2,897	5.4%	2,253	2.2%
	Sustaining	1,018	0.8%	979	1.0%	1,237	1.2%	1,031	0.8%	1,019	1.3%	1,512	2.8%	1,048	1.0%
		2,366	1.8%	2,964	3.0%	2,545	2.5%	2,099	1.6%	3,224	4.3%	4,408	8.3%	3,301	3.2%
General Plant		970	0.7%	969	1.0%	1,014	1.0%	776	0.6%	2,147	2.8%	2,014	3.8%	5,689	5.5%
Total Capitalized Overhead		**8,836**	**6.7%**	**9,062**	**9.1%**	**9,315**	**9.3%**	**9,529**	**7.5%**	**10,777**	**14.2%**	**10,969**	**20.6%**	**11,524**	**11.2%**

19.0 Reference: Exhibit B-1-6, page 3

Power Supply

"Water Fees in 2014 are reduced as a result of lower generation in 2013 due to an outage at the Corra Linn generating plant Unit 3."

19.1 Please provide details of the outage to Corra Linn generating plant Unit 3, including date of the outage and cost of replacement power."

Response:

The reference to Corra Linn Unit 3 should read Unit 2.

A ground fault occurred at the Corra Linn Unit 2 Generator on 13 July 2013. Preliminary investigations revealed that a ground fault most likely originated between the generator terminals and the switchgear. It is likely that because of the fault's proximity to the generator, the fault current arc initiated a fire which caused significant damage to the main generator cables and switchgear. A forensic investigation is being conducted by the insurers to determine the root cause.

The cost of replacement power is shown in the second column Actual Cost below and the forecast recoveries from insurance in the third column.

Month	Actual cost	Forecast Recoveries From Insurance
Jul-13	$ 190,000	
Aug 1 to 13	$ 208,542	
August 14 -31	$ 250,137	$ 250,137
Sep-13	$ 325,395	$ 325,395
Oct-13	$ 268,239	$ 268,239

19.2 If the outage occurred during the period of the labour disruption, could the outage have been avoided with normal operations and maintenance activities that would have been on-going but for the labour disruption?

Response:

The reference to Corra Linn Unit 3 should read Unit 2.

Please first refer to the response to ICG IR 2.19.1.

Corra Linn Unit 2 was scheduled for its annual inspection between October 1st and October 4th of 2013. With the failure of the Unit, this inspection was replaced with repair works.

The annual electrical inspection typically consists of generator and rotor insulation checks and excludes inspection of the area under the covers where the main leads terminate unto the switchgear or the unit. It is therefore unlikely that normal operations and maintenance activities could have predicted the failure.

The fault was therefore unrelated to the labour dispute. And even though the annual inspection was not due, by its very nature that inspection, even if done, it could not have prevented the outage because of the scope of the annual inspections.

20.0 Reference: Exhibit B-1-6, page 3

Operating Expenses

"The Company acknowledges that the labour disruption will result in a decrease in certain IBEW labour costs. However, there will also be cost increases in certain other areas as a result of the labour disruption, including:

- Costs of benefits remaining substantially unchanged, with a greater proportion of benefit loading costs charged to 2013 O&M expense rather than capital as a result of a carry-over of capital expenditures from 2013 to future years;
- A greater proportion of labour and vehicles costs being charged to 2013 O&M expense rather than capital as a result of the capital expenditure carry over from 2013 to future years; and
- Incremental labour costs incurred by Management and Exempt staff for covering IBEW work."

20.1 Please provide a detailed accounting by department for IBEW labour costs, and management and exempt staff costs for the period from January 1, 2013 to the start of the labour disruption and from the start of the labour disruption to the most current data available.

Response:

FBC does not collect or report department costs by labour group affiliation or for non-month end periods. While a certain degree of labour action initiated in mid-May 2013, June 26, 2013 is perceived as the beginning of the most substantial labour disruption. Therefore the table below represents the total O&M expense by department for January 1 to June 30, 2013, which represents the period prior to the most substantial labour disruption, and July 1 to October 31, 2013, the most recent month end. Note that the October YTD 2013 O&M expense column is not representative of all the increases or decreases in O&M attributable to the labour disruption, as FBC continues to analyze the financial results and ensure completeness of the financial effect in total and by department. Also note that O&M expenses are not incurred evenly throughout the year, due to timing of O&M and capital projects.

Departmental O&M Review

($ thousands)

	2013		
	January - June	July - October	October YTD
Generation	$ 1,225	$ 340	$ 1,565
Operations	$ 9,792	$ 6,592	$ 16,385
Customer Service	$ 3,787	$ 2,339	$ 6,125
Communications & External Relations	$ 458	$ 549	$ 1,007
Energy Supply	$ 531	$ 364	$ 894
Information Technology	$ 1,452	$ 932	$ 2,384
Engineering	$ 1,108	$ 939	$ 2,047
Operations Support	$ 964	$ 54	$ 1,018
Facilities	$ 1,967	$ 1,242	$ 3,209
Environment, Health & Safety	$ 434	$ 161	$ 595
Finance & Regulatory	$ 1,883	$ 1,443	$ 3,326
Human Resources	$ 870	$ 596	$ 1,466
Governance	$ 1,196	$ 724	$ 1,920
Corporate	$ 1,417	$ 1,820	$ 3,237
Advanced Metering Infrastructure	$ -	$ -	$ -
Total O&M	$ 27,084	$ 18,094	$ 45,178

20.2 Please provide FortisBC's policy on reimbursement of the cost of alcoholic beverages as part of submitted expenses.

Response:

FBC does not have a specific policy designed solely for the reimbursement of alcohol beverages; however for any such expenses to be approved, they would have to have been incurred for purposes related to Company business. It is the employee's responsibility to ensure that only such expenses are submitted for reimbursement, and the relevant supervisor's responsibility to review expense claims for compliance prior to approval. Responsibility and authority to enforce reimbursement for costs relevant for business purposes is placed with each manager who must ensure effective communication of this practice.

20.3 Please provide monthly totals of non-labour expenses incurred by management and exempt staff by department since January 2013.

Response:

As indicated in the response to ICG IR 2.20.1, FBC does not report department costs by affiliation.

21.0 Reference: Exhibit B-15, ICG IR 46.6, Exhibit B-1-1, Appendix H, and Exhibit B-7, BCUC 1.248.2

"The evaluation did not generally review or otherwise consider submissions and requests of the ICG in the 2012-13 RRA and ISP proceedings, with the specific exception of exploring the participants' project payback criteria."

21.1 Please confirm that incentive levels in the industrial sector were not considered with the Power Sense Industrial Efficiency Program Evaluation, by Sampson Research Consulting?

Response:

Confirmed.

21.2 Please explain and compare the DSM industrial sector energy approved savings of 2,580 MWh in 2013 with the 800 MWh forecast savings for each year of the PBR Plan?

Response:

The 2,580 MWh approved savings target was based on the average industrial efficiency results of the prior five year period (2006-2010), that were available on the June 2011 filing date.

The 2014-18 plan savings of 800 MWh/yr are based on the more recent years' savings (actual or forecast) as follows:

2011A	2012A	2013F
794	937	857

21.3 Please comment on whether the CPR Upgrade provided as an attachment to BCUC 1.248.2 justifies the decrease in plan savings from 2,580 MWh in 2013 to 800 MWh saving for each year of the PBR Plan?

Response:

Please refer to the response to ICG IR 2.21.2.

21.4 Please file the FortisBC Semi-Annual DSM Report Ending June 30, 2013, and the FortisBC Semi-Annual DSM Report Ending December 31, 2013 when it is available? Please continue to include programs savings and benefit/cost ratios by sector in the DSM reports?

Response:

Please refer to Attachment 21.4 for a copy of the FBC Semi-Annual DSM report to June 30, 2013. The requested report to Dec 31, 2013 will be filed with the BCUC by the end of the first quarter in 2014.

21.5 Please provide the approved savings as a percentage of the achievable potential for the industrial sector in 2013 based on the CPR and the plan savings as a percentage of the achievable potential for the industrial sector during the PBR Plan based on the CPR Update?

Response:

The following table compares the industrial sector electricity savings filed in FBC's DSM plan to the potential savings estimates from FBC's 2010 CPR (for 2013 only) and 2013 CPR Update (for the DSM Plan years 2014 to 2018).

Industrial Electricity Savings, MWh						
	2013	**2014**	**2015**	**2016**	**2017**	**2018**
FBC CPR Potential	1,563	1,226	1,277	1,327	1,378	1,429
Approved/Filed Plan	2,580	800	800	800	800	800
% of CPR	165%	65%	63%	60%	58%	56%

22.0 Reference: Exhibit B-15, ICG IR 46.8

"Due to the myriad of BC Hydro industrial sector program offers, compared to FBC's single Industrial Efficiency program offer, it is not possible to ascertain, compare and/or quantify a material difference (if any) in measure incentives."

22.1 Please file all evidence in the 2012-2013 RRA proceeding that compared incentives levels of BC Hydro and FortisBC? Please update the evidence for any program or incentive level changes made by BC Hydro or FortisBC since the 2012-2013 RRA proceeding?

Response:

Please refer to the response to ICG IR 1.46.8 with respect to BC Hydro incentive levels.

With respect to FBC, there has not been a material change in the industrial sector incentive levels.

22.2 Please comment on whether industrial sector costs as per cent of plan as presented in the table provided with Exhibit B1-15, BCUC IR 46.1 are relevant to the determination of incentive levels offered by FortisBC?

Response:

FBC believes the question intended to reference Exhibit B-15, the response to ICG IR 1.46.1.

FBC believes that plan achievement percentages can be one factor in determining incentive levels, as are other factors such as customer payback (the participant cost test).

If the Company has underestimated market demand in the industrial (or any other sector) it has the flexibility to shift budgets between program areas by up to 25 percent, and even beyond 25 percent if permission is sought and granted by the Commission.

22.3 Please extend the table provided with Exhibit B1-15, BCUC IR 46.1 to include industrial sector savings as a per cent of plan?

Response:

FBC understands ICG IR 2.22.3 to refer to the following table from Exhibit B-15, ICG IR 1.46.1.

Table 1 provides industrial sector costs as per cent of Plan achieved for the past five years.

Table 1

	Industrial Costs (Plan) ($ 000's)	Industrial Costs (Actual) ($ 000's)	% of Plan Achieved
2008	200	147	73%
2009	345	236	68%
2010	389	241	62%
2011	613	137	22%
2012	350	173	49%

FBC understands ICG IR 2.22.3 to request the electricity savings of the industrial sector for the PBR period (as filed in the DSM plan) compared to the total plans savings. The following table provides the planned industrial budget and savings compared to the program total.

	2014-2018 PBR Savings, MWh			2014-2018 PBR Program Budget, $		
Year	*Industrial*	*Total*	*%*	*Industrial*	*Total*	*%*
2014	800	12,800	6.3%	148	2,319	6.4%
2015	800	12,887	6.2%	150	2,397	6.3%
2016	800	12,823	6.2%	152	2,355	6.5%
2017	800	12,823	6.2%	154	2,392	6.4%
2018	800	12,823	6.2%	156	2,436	6.4%

22.4 Please identify any changes implemented or contemplated by FortisBC that might increase industrial sector costs as per cent of plan?

Response:

No such changes are implemented or contemplated at this time. Also please refer to the response to ICG IR 2.22.2.

22.5 Please calculate a forecast benefit cost ratio for the industrial sector assuming an incentive of 15 cents and 20 cents/kWh savings, assuming no payback period cap?

Response:

The Benefit/Cost ratio does not change whether the incentive is increased to 15 or 20 cents/kWh savings because the incentive amount is considered to be a transfer payment between parties (the incentive cost is simply a component of the "total cost" used in the TRC benefit/cost ratio calculation).

22.6 In response to Exhibit A-17, BCUC 107.3, please assume that a BC Hydro program with a DSM incentive level that is at least 60% greater than the comparable FortisBC DSM incentive level is a program not offered by FortisBC during the PBR period?

Response:

Please refer to the response to BCUC IR 2.107.3.

22.7 In response to Exhibit A-17, BCUC 107.4, please complete the same analysis by sector as well as on an aggregate basis? Please also provide the BC Hydro comparable data for the industrial sector?

Response:

FBC does not have sufficient time or resources to provide this additional level of analysis. Please also refer to the response to ICG IR 2.22.6.

23.0 Reference: Exhibit B-1-6, cover letter, page 1

"… FBC is only requesting approval of 2014 rates at this time; 2015 through 2018 rates are considered indicative only and will be updated as part of FBC's Annual Review process."

23.1 Please comment on whether FortisBC plans to file a further evidentiary update based on actuals and updates to forecast as of the end of 2013?

Response:

No, FBC does not plan to file a further evidentiary update in this proceeding. The principles on which the PBR Plan is based remain sound, and will not change as a result of any variances between current forecasts and 2013 year end results. Furthermore, the treatment of any 2013 variances has already been established in the 2012-2013 RRA decision, so there are no new factors to be considered.

FBC's proposals surrounding its Rate Stabilization Deferral Mechanism provide that year to year variances are identified as part of its Annual Review process and any resulting rate impacts incorporated into revenue requirements in the following year. FBC submits that a reasonable approach to managing variances between the currently forecast and final 2013 results is to retain the relevant variances in their appropriate deferral accounts for disposition in 2015.

24.0 Reference: Exhibit B-1-6, cover letter page 3

"FBC has updated its 2014 through 2018 Forecasts for Power Purchase Expense to incorporate power purchase agreements executed since the July 5, 2013 filing and updates due to revised market price forecasts."

24.1 Please file the power purchase agreements executed since July 5, 2013, and provide a summary table with price, volumes, and term.

Response:

Please refer to the response to ICG IR 2.11.1.

24.2 Please provide a full explanation with copies of all documents relied upon, and a summary table, of the update to the market price forecasts?

Response:

For the Evidentiary Update, FBC relied on an Argus Media publication entitled "Argus US Electricity" dated September 13, 2013 to provide a forecast for the Mid-C. A copy is included as Attachment 24.2. For the original filing, FBC used the Argus Media publication data May 13, 2013 and provided in the response to ICG IR 1.22.1. The following table shows a comparison of the two forecasts.

Market Price Update						
	On-Peak			Off-Peak		
	RRA Filing - July 5, 2013	Evidentary Update - October 18, 2013	Variance	RRA Filing - July 5, 2013	Evidentary Update - October 18, 2013	Variance
	Argus US Electricity - May 13, 2013	Argus US Electricity - September 13, 2013		Argus US Electricity - May 13, 2013	Argus US Electricity - September 13, 2013	
Jul-13	$42.90	N/A	N/A	$28.50	N/A	N/A
Aug-13	$47.65	N/A	N/A	$34.40	N/A	N/A
Sep-13	$42.00	N/A	N/A	$33.90	N/A	N/A
Oct-13	$37.25	$34.50	-$2.75	$32.85	$28.43	-$4.42
Nov-13	$38.75	$37.25	-$1.50	$33.35	$31.18	-$2.17
Dec-13	N/A	$41.43	N/A	N/A	$34.38	N/A
Jan-14	N/A	$38.25	N/A	N/A	$32.15	N/A
Feb-14	N/A	$36.00	N/A	N/A	$30.85	N/A
Mar-14	N/A	$32.95	N/A	N/A	$27.40	N/A
Q3 2013	$44.25	N/A	N/A	$32.25	N/A	N/A
Q4 2014	$39.15	$37.63	-$1.52	$34.00	$31.43	-$2.57
Q1 2014	$37.65	$35.75	-$1.90	$31.90	$30.10	-$1.80
Q2 2014	$28.00	$27.58	-$0.42	$13.95	$12.75	-$1.20
Q3 2014	$41.70	$43.25	$1.55	$29.90	$28.28	-$1.62
Q4 2014	$40.35	$39.90	-$0.45	$34.45	$34.15	-$0.30
Q1 2015	$40.00	$38.73	-$1.27	$34.95	$32.78	-$2.17
Q2 2015	$29.30	$29.05	-$0.25	$15.90	$14.90	-$1.00
Q3 2015	N/A	$44.40	N/A	N/A	$28.70	N/A
Cal-14	$36.90	$36.60	-$0.30	$27.60	$26.35	-$1.25
Cal-15	$38.35	$38.40	$0.05	$28.65	$27.70	-$0.95
Cal-16	$39.10	$40.00	$0.90	$28.70	$29.10	$0.40
Cal-17	$42.50	$42.40	-$0.10	$31.25	$30.85	-$0.40

25.0 Reference: Exhibit B-1-6, page 3

"Therefore there is currently no forecast impact to overall operating expense as a result of the labour disruption."

25.1 Please comment on the merits of a deferral account to refund variances between forecast and actual labour expense for 2013?

Response:

FortisBC does not believe there are any merits to such a deferral account.

During the labour disruption, the Company has not paid salaries to IBEW staff. However, this does not translate directly to O&M labour savings experienced by the Company, as this is representative of only one component of O&M labour expense.

As explained on page 3, item 2 of the Evidentiary Update, these savings in IBEW payroll have been offset by several items. With respect to labour costs specifically, it's important to recognize the following:

1. Approximately 60 percent of salaries paid to IBEW staff are traditionally allocated to capital or third party services. Therefore, of the salaries not paid to IBEW staff, only 40 percent could be considered avoided O&M costs. The remainder is part of the capital expenditures and third party work not completed in 2013, which in the case of capital has been rescheduled to 2014 and 2015, as explained on page 57 and 58 of the Evidentiary Update. The third party work that has been reduced, deferred or cancelled does not impact the labour expense of the Company;
2. Despite the labour disruption, FBC's cost of employee benefits has remained substantially unchanged. As a result of capital expenditures not completed in 2013, a greater proportion of these benefits are included in O&M rather than being loaded into capital;
3. With the reduced workforce during the labour disruption, FBC has experienced higher than normal overtime costs as a result of qualified management and exempt staff performing IBEW work; and
4. There may be additional impacts to labour costs as a result of the labour disruption yet to be recognized in 2013.

As a result of the labour-related factors above, the salaries not paid to IBEW staff are being offset by other components of O&M labour expense that have increased.

In addition to the above, FBC has recognized some labour as deferred O&M expense in 2013, which has been discussed further in the response to BCUC IR 2.90.13.

26.0 Reference: Exhibit A2-15, page 16

"Allocation of energy efficiency spending among different customer classes and categories of program expenditures reveals additional information about program strategies and administration. Our results show that, generally, states are spending slightly more on non residential electricity programs than they are spending on residential electricity programs. The allocation decisions seem to be driven by both a regulatory concern for equity among customer classes and by the costs and availability of energy efficiency measures in a given customer class. The greater levels of spending on non-residential programs suggest that energy efficiency resources are more accessible and affordable in these sectors than they may be in the residential sector."

26.1 Please provide the program spending in the residential and industrial sector as a percentage of load for each sector by FortisBC and BC Hydro from 2008 to 2012?

Response:

Residential	FBC	BCH
program spending* as a percentage of load**		
2012 (F2013 for BCH)	0.23%	0.16%
2011 (F2012 for BCH)	0.15%	0.16%
2010 (F2011 for BCH)	0.16%	0.16%
2009 (F2010 for BCH)	0.14%	0.17%
2008 (F2009 for BCH)	0.12%	0.13%

* *Program costs, including planning and evaluation costs; excludes costs related to supporting initiatives, codes/standards and rates*

** *Does not include Wholesale load*

Industrial	FBC	BCH
program spending* as a percentage of load**		
2012 (F2013 for BCH)	0.07%	0.31%
2011 (F2012 for BCH)	0.06%	0.35%
2010 (F2011 for BCH)	0.12%	0.18%
2009 (F2010 for BCH)	0.13%	0.19%
2008 (F2009 for BCH)	0.09%	0.10%

* *Program costs, including planning and evaluation costs; excludes costs related to supporting initiatives, codes/standards and rates*

** *Does not include Wholesale load*

26.2 Please comment on whether FortisBC agrees that energy efficiency resources are more accessible and affordable in the industrial sector than in the residential sector?

Response:

FBC agrees. FBC believes that industrial programs are more accessible since industrial customers are given key account status and thus are frequented by FBC's Technical Advisors on a regular interval, at least once a year, to review any capital plans to identify DSM opportunities.

Generally speaking industrial energy efficiency projects enjoy a shorter payback for customers as compared to residential programs.

26.3 Please comment on the factors that FortisBC considers to be the most significant drivers of the allocation of program spending in the residential, commercial and industrial sectors?

Response:

Please refer to the response to BCUC IR 1.248.11.

27.0 Reference: Exhibit B-1, page 103

"Because of this, the Company anticipates that the block price for all heavy load hours will not accurately reflect the cost that the Company expects to pay for capacity to meet its peak demand. The Company adds a 20 percent premium to the block forecast of heavy load energy to account for the peak hour premium. Additionally, these forecasts are converted to Canadian dollars, based on the Company's forecast exchange rates."

27.1 Please provide a current two year term block price for this winter for all hours delivered to the FortisBC system?

Response:

FBC believes a current price for a winter block for all hours for the next two winters (including the winter for 2013/2014 and the winter of 2014/2015) would be approximately $39/MWh delivered to the FBC system.

27.2 Please provide the forecast price for this winter that the 20 per cent premium would be applied to?

Response:

The 20 percent premium represents an estimate of the increased cost to purchase capacity from the open market during the peak hours of the month in order to meet the demand on the FBC system. It is during these times when prices are typically the highest, since other utilities in the Northwest Power Pool usually experience similar high demand periods, resulting in an upward pressure on market prices in the region.

FBC cannot lock in purchases over the peak in advance, since the peak days and peak hours are not known in advance. These purchases need to be made either on the day before or the day of the peak day, when it can be anticipated that peak loads will occur.

Please refer to the response to ICG IR 2.24.2 for the forecast market prices for this winter.

For example, the forecast Mid-C price for January 2014 Heavy Load Hours (HLH) is $38.25/MWh. FBC expects that this price would be, on average, approximately 20 percent higher on the peak hours of the month, equal to $45.90. With the inclusion of $4/MWh for transmission, losses and ancillary services, the cost would be approximately on average $49.90/MWh delivered to the FBC service territory on the peak hours of January 2014. Actual prices in any one hour could vary significantly more than this amount.

28.0 Reference: Exhibit B-1, page 106 and page 109

"With the Waneta Expansion project forecast to come online in 2015, the Company will not have a capacity deficit, and will have surplus capacity compared to its forecast peak load requirements which it will sell in order to mitigate power purchase expense. The estimate of this mitigation is included in line 3 in Table C2-9 above."

"Transactions between FBC and its affiliated Non-Regulated Business (NRBs) are conducted in accordance with FBC's Code of Conduct (COC) and Transfer Pricing Policy (TPP)."

28.1 Please provide a full description calculation of the forecast payments, including a pro forma invoice, under the WAX CAPA that have been relied by FortisBC to calculate line 3 in Table C2-9?

Response:

Please refer to the response to ICG IR 1.24.1.

28.2 Please provide by year the surplus capacity, the expected per unit sale price, and the aggregate sale price of the surplus capacity forecast to mitigate the net price in line 3 in Table C2-9.

Response:

Please refer to the response to ICG IR 1.24.1.

28.3 Please provide all evidence relied upon to forecast the proceeds from the sale of the surplus capacity.

Response:

FBC has estimated the proceeds from the sale of surplus capacity based on the market price forecast as shown in the response to ICG IR 2.24.2, and based on confidential offers from potential buyers.

28.4 Please confirm that the risk of variances from the forecast of the proceeds from the sale of surplus WAX CAPA capacity is to be borne by customers.

Response:

Confirmed, as this amount is part of Power Purchase Expense.

28.5 Please comment on whether transactions under the WAX CAPA are required to be conducted in accordance with FBC's Code of Conduct and Transfer Pricing Policy. If not, please explain why not?

Response:

The WAX CAPA is an energy supply agreement pursuant to Section 71 of the UCA and transactions under that agreement are not subject to FBC's Code of Conduct and Transfer Pricing Policy.

The reference on page 109 relates to Other Income, not to Power Purchase Expense. FBC performs work on the WAX facility pursuant to a Subcontractor Agreement between WELP and FHPI, and those transactions are conducted in accordance with the Code of Conduct and Transfer Pricing Policy.

29.0 Reference: Exhibit B-1-1, Appendix F3

Capitalized Overhead

FortisBC states that KPMG was retained by FortisBC Inc. to assist with its overhead capitalization study (Exhibit B-1-1, Appendix F3 p.4).

29.1 Please provide the following with respect to the study:

29.1.1 the terms of reference of the study;

Response:

The terms of reference are outlined in the Executive Summary of the study.

29.1.2 the curricula vitae of the engagement partner and manager; and

Response:

Please refer to Attachment 29.1.2 for a copy of the curricula vitae of the engagement partner, Peter Greenwood.

29.1.3 the fee paid by FortisBC.

Response:

Due to the commercial sensitivity and market competitiveness regarding the fees paid to KPMG, the Company respectfully declines to disclose the fee paid by FortisBC.

29.2 Please provide a continuity schedule for the years 2000 to 2012 in a comparable format to Exhibit B-7, BCUC IR.1.29.2 that clearly shows the following information:

29.2.1 Year;

29.2.2 unloaded gross capital expenditure;

29.2.3 total direct overhead;

29.2.4 capitalized overhead (excluding direct overhead);

29.2.5 AFUDC; and

29.2.6 cost of removals.

Response:

The table below provides the data from 2000 to 2012 in a format comparable to Exhibit B-7, BCUC IR 1.29.2.

Capital Expenditure Parameters		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Unloaded Gross Capital Expenditure	**A**	**33,202**	**37,736**	**74,480**	**49,616**	**82,493**	**104,910**	**94,854**	**129,189**	**99,589**	**99,168**	**130,491**	**76,209**	**52,391**
Add Loadings:														
Capitalized Overheads		2,482	2,450	2,195	2,815	2,563	3,392	8,382	8,836	9,062	9,315	9,529	10,777	10,969
Direct Overheads		-	-	-	-	1,348	3,750	5,067	5,727	4,944	5,508	5,157	4,814	4,541
AFUDC		590	846	2,451	3,370	2,434	3,335	2,360	2,989	3,009	3,234	4,733	1,833	489
Total Loadings:	**B**	**3,072**	**3,296**	**4,646**	**6,185**	**6,345**	**10,477**	**15,809**	**17,552**	**17,015**	**18,057**	**19,419**	**17,423**	**15,998**
Total Loaded Gross Capital Expenditure	**C = A+B**	**36,274**	**41,032**	**79,126**	**55,801**	**88,838**	**115,387**	**110,663**	146,741	116,604	117,225	149,910	93,632	68,388
Conversion Multiplier (For converting Unloaded Capital to Loaded Capital)	**C/A**	**1.09**	**1.09**	**1.06**	**1.12**	**1.08**	**1.10**	**1.17**	**1.14**	**1.17**	**1.18**	**1.15**	**1.23**	**1.31**
Less Cost of Removals (COR)	**D**	673	582	67	1,307	2,951	2,077	1,315	2,999	5,025	4,502	7,872	5,267	3,710
Total Loaded Gross Capital Expenditure without COR	**E =C-D**	35,601	40,450	79,059	54,494	85,887	113,310	109,348	143,742	111,579	112,723	142,038	88,365	64,679

30.0 Reference: Exhibit B-1-1, Appendix F3

Comparability of KPMG data

In Table 1 KPMG shows the build-up of the direct overhead load pool based on the 2013 Budget, where a total of $4.7 million of overhead costs of certain departments were allocated to the direct overhead pool and were therefore capitalized (Exhibit B-1-1, Appendix F3 p.20).

In Table 2 KPMG shows the build-up of a capitalization rate for by department, with the total indirect capital related cost capitalized under this model being $8.5 million (Exhibit B-1-1, Appendix F3 p.24).

30.1 Each table referred to above refers to departments but they are different in each table. Please provide a spread sheet that starts with a control budget for 2013 of all departments in sufficient detail and granularity to be able to identify the departments in Table 1.

Response:

			2013 Budget			
Table 1 Departments	**Table 2 Departments**	**Cost Centre**	**Direct Overhead Capitalized**	**Total O&M**	**Overhead Capitalized (Note 1)**	**Net O&M**
Operations - Okanagan	Operations	Network Operations	920	3,804		
Operations - Kootenay	Operations	Network Services - Kootenay	360	313		
Line Construction	Operations	Network Operations	370	2,255		
System Control	Operations	System Control	340	2,322		
Station Capital	Operations	Network Services-Stn Capital	140	3,085		
Project Management Office	Engineering Services	Engineering Services	590	-		
Engineering & Engineering Standards	Engineering Services	Engineering Services	480	1,400		
System Planning	Engineering Services	System Planning	700	184		
Asset Management	Engineering Services	Mandatory Reliability Standards	360	1,187		
Distribution Engineering	Engineering Services	Engineering Services	120	21		
Procurement & Materials Handling	Operations Support	Procurement & Purchasing	150	505		
Environment, Health & Safety	Environment, Health & Safety		60	953		
Finance	Financial & Regulatory Services		80	4,271		
	All other departments			37,322		
		Total	**4,670**	**57,621**	**11,524**	**46,097**

Note 1: Please note that the Company does not allocate Overhead Capitalized by department.

30.2 In addition, or as part of the above spreadsheet response, please provide a spreadsheet that offers the same level of granularity and shows the following information for both 2013 and for the PBR period 2014 to 2018:

Column 1	Departments
Column 2	“Gross” budget

Column 3	Amounts directly charged to capital
Column 4	Amounts charged to Deferral Accounts
Column 5	Direct Overhead capitalized
Column 6	Overhead Capitalized
Column 7	O&M charged to operations

Response:

The Company is unable to provide the amounts charged directly to capital or to deferral accounts for 2013. The Company does budget for salaries and wages charged out, but the amounts are on a net basis of various charges in and out of departments. The charges can include net:

- Charges to capital,
- Charges to 3rd parties,
- Charges to deferral accounts,
- Charges to/from other related companies; and
- Charges to/from other departments.

There are also vehicle recoveries, material handling recoveries and other absorption recoveries that are charged to both capital and third parties.

31.0 Reference: Exhibit B-1-1, Appendix F3

Direct Overhead Pool

KPMG states "that a total of $4.7 million of overhead costs were allocated to the direct overhead pool and were therefore capitalized" (Exhibit B-1-1, Appendix F3 p.20).

31.1 Will the amount of $4,670,000 be the amount actually capitalized by FortisBC in 2013?

Response:

No. The amount of Direct Overhead capitalized during 2013 will be the amount of Direct Overhead actually incurred in the year. This may or may not be equal to the forecast amount.

31.2 Please describe how, if at all, this amount can change over the course of 2013.

Response:

The $4.7 million referred to is the 2013 budgeted amount and is comprised of various estimates of labour hours and non-labour costs. Actual costs may vary due to differences in actual hours and actual other costs incurred.

31.3 Please explain in as much detail as possible how the amount of $4,670,000 will actually be recorded in FortisBC's work order system and its fixed asset ledger. Will it be charged to CWIP over the year or into work orders as they are closed out or what?

Response:

Direct Overhead is charged to the relevant work orders in the following manner:

- A Direct Overhead allocation factor or charge-out rate is calculated by dividing the forecast annual total Direct Overhead Loading costs by the forecast annual total Transmission and Distribution project costs;

- Each month, each Transmission and Distribution project is systematically charged Direct Overhead based on the pro rata project expenditures in the month;
- Projects are transferred from CWIP to the fixed asset ledger as they are completed; and
- Any variance in the amount of the Direct Overhead loading pool cost and Direct Overhead charged out is allocated to Transmission and Distribution projects.

31.4 How will the amount capitalized be affected, if at all, by variances of actual and budgeted capital expenditures?

Response:

The amount of Direct Overhead capitalized is not be affected by variances in the actual versus budgeted capital expenditures. The actual Direct Overhead pool, which consists of actual direct overhead costs incurred, is allocated to Transmission and Distribution projects on a pro rata basis.

Please also refer to the response to ICG IR 2.31.3.

31.5 Many utilities maintain different types of work order-capital, recoverable, maintenance etc. What is FortisBC's practices in this regard? Does FortisBC charge all types of work order with direct overhead or just capital work orders?

Response:

FBC utilizes several types of work orders including, but not limited to operating, capital, salvage and recoverable type orders. Direct Overhead is only charged to Transmission and Distribution capital orders.

32.0 Reference: Exhibit B-1-1, Appendix F3

"Administrative Burden"

KPMG states that its study examined FortisBC's direct overhead loading methodology, which captures project specific T&D capital costs that have not been directly charged to capital projects, due to the administrative burden required to do so (Exhibit B-1-1, Appendix F3 p.5).

32.1 Please describe the "administrative burden" referred to.

Response:

The administrative burden referred to in this context includes, but is not limited to, the effort required by many different individuals to charge capital related time to many different projects as well as the coding of every capital related phone bill, capital related invoice, or other capital related item to many different orders.

As the Company stated in its 2004 Revenue Requirements Application where this methodology was first introduced and approved by the Commission,

"It must be noted that every timesheet, phone bill, invoice, or other item that is capital in nature is identified and directly charged to these (Direct Overhead loading) capital orders. There is no allocation made – these are direct charges, at source. It is in the distribution from those "overhead" capital orders to the individual projects where a pro-rata loading mechanism is used."

33.0 Reference: Exhibit B-1-1, Appendix F3

Customer Impact

33.1 Please provide a working spreadsheet that compares the impacts on each year's revenue requirements of:

33.1.1 capitalizing $1,000 of direct overhead loading and recovering it by way of a return on and of capital ; and

Response:

The revenue impact for capitalizing $1,000 of direct overhead loading and recovering it by way of a return on capital would approximately be $28. A simple calculation is shown below, that also specifies the assumptions used. Please also refer to Attachment 33.1.1 for the electronic spreadsheet.

Revenue Impact Calculation:

Additional Capital	1,000	**A**	
Rate Base Change	500	**A/2 = B**	Mid Year Rate Base
Cost of Equity	18	**B*40%*9.15% = C**	Equity: 40% & ROE: 9.15%
Cost of Debt	18	**B*60%*5.94% = D**	Debt: 60% & Average Debt Rate: 5,94%
Income Tax	(8)	**G**	Refer calculation below
Increased Revenue	**28**	**A**	

Income Tax Calculation:

Increased Revenue	28	**A**	Refer calculation above
Less Cost of Debt	(18)	**(D)**	Refer calculation above
Less CCA Tax Shield	(40)	**A*50%*8% = (E)**	Applied Half Year Rule & CCA Rate of 8%
Total	(29)	**F = A-(D+E)**	
Income Tax	**(8)**	**F*26% = G**	Tax Rate: 26%

Note: ***Please note that "Depreciation" has not been considered in the calculation since it takes effect only in the year subsequent to plant additions.***

33.1.2 recovering it from customers through rates in the year incurred.

Please spell out all assumptions used- e.g. capital structure, cost of debt, ROE, income tax rate etc.

Response:

The revenue impact for recovering an incremental $1,000 from customers through rates in the year incurred will be an additional Revenue Requirement of an equivalent amount (i.e., $1,000). This occurs since the Cost of Equity, Cost of Debt and Income Taxes in this case are unaffected.

34.0 Reference: Exhibit B-1-1, Appendix F3

Survey Model

KPMG states that "Under the Survey Model, the Company interviewed department heads and senior managers within the corporate functions and business units listed in Table 2. Management sought to understand and identify those company departments that support, either directly or indirectly, capital projects at FBC" (Exhibit B-1-1, Appendix F3 p.21).

34.1 For all the departments listed on Table 2 which reported indirect capital related O&M expenditures, please provide the responses of senior management to the each of the survey questions in Appendix B.

Response:

Please refer to Attachment 34.1.

35.0 Reference: Exhibit B-1-1, Appendix F3

Capital Intensity

KPMG states that “the relative proportions of capital-related work (capital intensity) for 2013 in those corporate costs within the operating business units are determined” (Exhibit B-1-1, Appendix F3 p.25).

35.1 Please provide the derivation of each of the capital intensity calculations.

Response:

The capital intensity for each of the business units is determined by calculating the ratio of hours charged to Capital versus O&M. 2011 hours data was used, as that was the last full year of hourly data that was available at the time of the study. As is shown below, the Capital Intensity Ratio for Generation was determined to be 72 percent. Similarly, the Capital Intensity Ratio for Network Operations and Customer Service were determined to be 57 percent and 7 percent, respectively.

Generation Capitalized Overhead Allocation Profile

Corporate Overhead		**$**	**3,933**
O&M	14%		28%
Capital	36%		72%
	50%		**100%**
Capitalized Overhead		**$**	**2,832**

2011 Hours Charged to:

FBC O & M	14%
FBC Capital	36%
3rd party	50%
	100.0%

Network Operations Capitalized Overhead Allocation Profile

Corporate Overhead	**$**	**11,548**
O&M	39%	43%
Capital	53%	57%
	92%	**100%**
Capitalized Overhead	**$**	**6,582**

2011 Hours Charged to:

FBC O & M	39%
FBC Capital	53%
3rd Party	8%
	100.0%

1

Customer Service Capitalized Overhead Allocation Profile

Corporate Overhead	**$**	**6,123**
O&M	91%	93%
Capital	7%	7%
	98%	**100%**
Capitalized Overhead	**$**	**429**

2011 Hours Charged to:

FBC O & M	91%
FBC Capital	7%
3rd Party	2%
Total	100%

2

3

36.0 Exhibit B-1-1, Appendix F3

Surveys methodology

KPMG states that the rates derived by both the survey and mathematical models exclude direct overhead loading (Exhibit B-1-1, Appendix F3 p.27).

36.1 Please perform the survey model without excluding direct overhead loading.

Response:

Excluding the Direct Overhead loading would not change the Capitalized Overhead rate as the costs that would have been charged to capital via the Direct Overhead loading methodology would be charged directly to capital.

36.2 Please perform the mathematical model without excluding direct overhead loading.

Response:

Excluding the Direct Overhead loading would not change the Capitalized Overhead rate as the costs that would have been charged to capital via the Direct Overhead loading methodology would be directly charged to capital.

37.0 Reference: Exhibit B-1, Table 6-5, page 1

FortisBC states "[T]he forecast capitalized overhead amounts for 2014 through 2018 are equal to 20 percent of the O&M as calculated under the PBR Plan as shown in Table B6-5 on page 53, Exhibit B-1 of the Application."

37.1 Does FortisBC track O&M over the year and capitalize exactly 20% each month?

Response:

Capitalized Overhead is not a function of actual O&M in the year. FBC calculates a Capitalized Overhead loading factor by dividing an amount equal to 20 percent of the Commission Approved Gross O&M in the year by the forecast total Capital Expenditures in the year. Each month the Capitalized Overhead loading factor is applied to capital expenditures in the month and one-twelfth of the annual Capitalized Overhead is credited to the income statement. At year end, any variance between the actual Capitalized Overhead booked to capital in the year and the amount of approved Capitalized Overhead is allocated to the capital expenditures on a pro rata basis.

37.2 Please explain in as much detail as possible how the amount actually capitalized will be recorded in FortisBC's work order system and its fixed asset ledger. Will it be charged to CWIP over the year or into work orders as they are closed out or what?

Response:

Capitalized Overhead is charged to the relevant fixed assets in the following manner:

- Each month, one-twelfth of the annual Capitalized Overhead budget is charged to a non-rate base capital account and a corresponding credit is booked to the income statement;
- Projects are transferred from CWIP to the fixed asset ledger as they are completed; and
- At the end of the year, prior to closing the account for the fiscal period, the Capitalized Overhead will be charged to the appropriate asset accounts on a pro rata basis according to the actual expenditures in the year by asset class.

37.3 Many utilities maintain different types of work order-capital, recoverable, maintenance etc. What is FortisBC's practices in this regard? Does FortisBC charge all types of work order with capitalized overhead or just capital work orders?

Response:

FBC utilizes several types of work orders including, but not limited to, operating, capital, salvage and recoverable type orders. Capitalized Overhead is only charged to capital orders.

37.4 Please explain how incentives paid to the various levels of FortisBC employees (management, out-of-scope, and union) are charged to capital. Please calculate how much incentive (as defined above) was capitalized in 2007-2012:

37.4.1 directly to the work order; and

37.4.2 indirectly, by way of direct overhead loading and capitalized overhead.

Response:

Incentive amounts are included in the derivation of the fringe benefit loading that is applied to each hour (regular) worked. The fringe benefit loading recovers costs associated with medical, dental, pension and OPEB, time away including statutory holidays, vacation, sick pay and incentives and is included as a loading on every hour worked. By doing so, labour hours charged directly to capital also include fringe benefit loading.

The amount of incentive charged to capital will vary each year as a function of the relative labour charges to capital versus other areas, including operating and third-party work.

The following amounts are estimates of the amount of incentive charged to capital.

($000s)

	2007	2008	2009	2010	2011	2012	2013
Estimated Incentive Amount in:	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Base**
Direct Charges to Capital	**1,100**	**1,200**	**1,200**	**1,100**	**1,500**	**1,500**	**1,500**
Direct Overhead	**100**	**100**	**200**	**200**	**200**	**200**	**200**
Capitalized Overhead	**300**	**300**	**400**	**300**	**400**	**500**	**500**
Charged to Capital	**1,500**	**1,600**	**1,800**	**1,600**	**2,100**	**2,200**	**2,200**

37.5 Please provide details of the incentives that have been built into the 2013 budget and the 2014-2018 forecast and the amount that will be capitalized directly to the work order, and indirectly, by way of direct overhead loading and capitalized overhead.

Response:

The 2014 – 2018 incentive forecast is effectively the 2013 incentive forecast of approximately $3.2 million escalated for inflation each year. Each year, approximately 68 percent of the annual incentive is expected to be capitalized directly to capital or indirectly via capitalized overhead.

Please also refer to the response to ICG IR 2.37.4.

38.0 Reference: Exhibit B-1-1, Appendix H

Demand Side Management (DSM)

In Table H1-5 of Appendix H FortisBC identified the program components of its supporting initiatives.

38.1 Please present the table by expenditure type (viz. salaries, expenses grants etc.).

Response:

As Supporting Initiatives projects usually means supporting and/or working in collaboration with other organizations, it is more difficult to provide a detailed allocation of funds. The following table expresses the expenditures expected in 2014-18:

Component	Salary (program design and/or management, admin)	Sponsorships, grants, marketing collateral, etc.
Public awareness	50,000	50,000
Community energy planning	5,000	15,000
Trades training	2,000	8,000
Education (schools)	5,000	45,000
Codes and standards	5,000	5,000

FortisBC states that in 2012 "[T]he Supporting Initiative costs for 2012 were $816 thousand or 113 percent of the $725 thousand Plan. The Conservation Culture costs included in Supporting Initiatives were $360 thousand. Supporting Initiatives and Conservation Culture spending continues to drive community outreach and direct customer communication, which is a strong component of PowerSense programming" (Exhibit B-1-1, App H2, p.11)

38.2 Please explain the reduction in supporting initiatives costs from $816,000 in 2012 to $195,000 in each of the years 2013-2018.

Response:

This program area was reduced in order to keep an appropriate balance between incentives (paid to participants) and non-incentive costs (program administration, planning and evaluation and supporting initiatives).

The following table illustrates the cost differences by component:

Supporting Initiatives	**2012**	**2014**
Public Awareness	$ 604,000	$ 100,000
Community Energy Planning	$ 75,000	$ 20,000
Education (trades and school)	$ 133,000	$ 60,000
Codes and Standards	$ 4,000	$ 10,000
Total	**$ 816,000**	**$ 190,000**

The majority of cost reductions are in Communications costs (promotional material development, media buys and staff labour) and in the elimination of a category of staff labour (Conservation Ambassadors). Additionally the Community Energy component was reduced by eliminating Community Energy Diets from the proposed DSM plan.

Note: the 2014 Supporting Initiatives plan amount is $190 thousand, not the $195 thousand amount referenced in the question.

FortisBC sets out its forecast expenditures on P&E in Table H1-6 of Appendix H, of approximately $500,000 per year.

38.3 Please explain the decrease in expenditures in 2014-2018 from the $728,000 and $760,000 incurred in 2012 and 2013 respectively.

<u>Response:</u>

FBC has reduced: P&E staffing by 0.5 FTE, office expenses, general consultant budget and reconfigured the implementation of the M&E Plan (please see Appendix H3).

39.0 Reference: Exhibit B-1-1, Appendix H

Incentives

39.1 For both Supporting Initiatives and Planning & Evaluation, please identify the amount of incentives to employees included in actual amounts paid in 2012 or those forecast to be paid in 2013. Do the amounts included in the annual forecasts for 2014-2018 include any such incentives?

Response:

Part of the short-term incentive (STI) plan for DSM (M&E) employees includes personal goals that relate to the management of DSM programs. These goals are included in the overall evaluation of the employees' performance, but there is no direct or quantitative linkage between the program elements named in the question and the STI amounts. STI payments are indirectly funded through labour loadings charged to all departments, including PowerSense.

40.0 Reference: Exhibit B-1-1, Appendix H

Accounting Policy

40.1 When did FortisBC begin to defer Supporting Initiatives and Planning & Evaluation expenditures as part of its DSM expenditures?

<u>Response:</u>

Planning & Evaluation expenditures have been incorporated in deferred DSM expenditures for as long as the program expenditures have been capitalized under G-47-89.

Public awareness, which is a component of Supporting Initiatives, was the last element to be allowed to be deferred in 2005 under Decision G-52-05.

40.2 Please provide the Order of the Commission and reasons therefor.

<u>Response:</u>

Attachment 40.2 contains the relevant excerpt from Order G-52-05.

41.0 Reference: Exhibit B-1-1, Appendix H

Customer Impact

41.1 Please provide a working spreadsheet that compares the impacts for both a 10-year and a 15-year period on each year's revenue requirements of:

41.1.1 capitalizing $1,000 of DSM supporting initiatives and recovering it by way of a return on and of capital ; and

Response:

Please refer to the tables below and Attachment 41.1 which contains the working spreadsheet. Table 1 calculates the Revenue Impact for 10-years for capitalizing $1,000 of DSM supporting initiatives and recovering it by way of a return on and of capital. Table 2 calculates the Revenue Impact for 15-years for capitalizing $1,000 of DSM supporting initiatives and recovering it by way of a return on and of capital.

Table 1: Revenue Impact for 10-years for capitalizing $1,000 of DSM Supporting Initiatives

Revenue Requirement Calculation:	Year-1	Year-2	Year-3	Year-4	Year-5	Year-6	Year-7	Year-8	Year-9	Year-10
Capital Addition Opening	-	1,000	900	800	700	600	500	400	300	200
Additions during the Year	1,000	-	-	-	-	-	-	-	-	-
Less Depreciation / Amortization	-	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
Capital Addition Close	1,000	900	800	700	600	500	400	300	200	100
Mean (Mid Year) Depreciated Capital Variance	500	950	850	750	650	550	450	350	250	150
Cost of Equity	18	35	31	27	24	20	16	13	9	5
Cost of Debt	18	34	31	27	23	20	16	13	9	5
Depreciation	-	100	100	100	100	100	100	100	100	100
Income Tax	(8)	20	21	22	22	23	23	23	23	23
Revenue Impact	**29**	**189**	**183**	**176**	**170**	**163**	**156**	**149**	**141**	**134**

Table 2: Revenue Impact for 15-years for capitalizing $1,000 of DSM Supporting Initiatives

Revenue Requirement Calculation:	Year-1	Year-2	Year-3	Year-4	Year-5	Year-6	Year-7	Year-8	Year-9	Year-10	Year-11	Year-12	Year-13	Year-14	Year-15
Capital Addition Opening	-	1,000	933	867	800	733	667	600	533	467	400	333	267	200	133
Additions during the Year	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Depreciation / Amortization	-	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)
Capital Addition Close	1,000	933	867	800	733	667	600	533	467	400	333	267	200	133	67
Mean (Mid Year) Depreciated Capital Variance	500	967	900	833	767	700	633	567	500	433	367	300	233	167	100
Cost of Equity	18	35	33	31	28	26	23	21	18	16	13	11	9	6	4
Cost of Debt	18	35	32	30	28	25	23	20	18	16	13	11	8	6	4
Depreciation	-	67	67	67	67	67	67	67	67	67	67	67	67	67	67
Income Tax	(8)	9	10	11	12	13	14	14	15	15	15	16	16	16	16
Revenue Impact	**29**	**146**	**142**	**138**	**135**	**131**	**126**	**122**	**118**	**113**	**109**	**104**	**99**	**94**	**90**

41.1.2 recovering it from customers through rates in the year incurred.

Response:

The revenue impact for recovering an incremental $1,000 from customers through rates in the year incurred will be an additional Revenue Requirement of an equivalent amount (i.e., $1,000). This occurs since the Cost of Equity, Cost of Debt and Income Taxes in this case are unaffected.

41.2 Please spell out all assumptions used- e.g. capital structure, cost of debt, ROE, income tax rate etc.

Response:

The assumptions used are indicated below:

1	Equity Ratio	40.00%
2	Debt Ratio	60.00%
3	ROE	9.15%
4	Average Debt Rate	6.00%
5	Depreciaton / Amortization Rate (10 Years)	10.00%
6	Depreciaton / Amortization Rate (15 Years)	6.67%
7	Income Tax Rate	26.00%
8	CCA Rate	8.00%

42.0 Reference: Exhibit B-1, Section 4

Deferral Accounts

42.1 Please provide a working spreadsheet that compares the impact on revenue requirements (including the impact of income tax) for the years 2013 to 2018 of the Commission allowing FortisBC to earn a return on the unamortized balances on its deferral accounts (excluding DSM) of:

42.1.1 Weighted Average Cost of Capital;

42.1.2 Weighted Average Cost of Debt; and

42.1.3 FortisBC's forecast short-term interest rates.

Response:

The requested calculation is shown in the Table below and Attachment 42.1 contains the working spreadsheet.

Revenue Impact Analysis	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Remarks**
Total Unamortized Deferred Year End Rate Base Balance	19,052	20,995	(4,462)	2,939	13,575	18,927	18,372	
Less Year End Net DSM Balance	(14,877)	(17,142)	(18,037)	(18,910)	(19,610)	(20,192)	(20,661)	
Total Year End Deferred excluding DSM	**4,175**	**3,853**	**(22,499)**	**(15,971)**	**(6,035)**	**(1,265)**	**(2,289)**	**A**
Prior Year Deferred excluding DSM		4,175	3,853	(22,499)	(15,971)	(6,035)	(1,265)	**B**
Mid Year Rate Base (Deferred Related)		**4,014**	**(9,323)**	**(19,235)**	**(11,003)**	**(3,650)**	**(1,777)**	**C = (A+B)/2**
Assumptions Used:								
FBC Equity Ratio		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	**D**
FBC Debt Ratio		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	**E**
Income Tax Rate		25.75%	26.00%	26.00%	26.00%	26.00%	26.00%	**F**
FBC ROE %		9.15%	9.15%	9.15%	9.15%	9.15%	9.15%	**G**
FBC Weighted Average Cost of Debt (WACD)		5.72%	5.94%	5.74%	5.80%	5.83%	5.83%	**H**
FBC's Forecast Short Term Interest Rates (ST)		2.40%	2.60%	3.50%	4.60%	4.80%	4.80%	**I**
Revenue Impact Calculation:								
Cost of Equity		147	(341)	(704)	(403)	(134)	(65)	**J = C*D*G**
Cost of Debt		138	(332)	(662)	(383)	(128)	(62)	**K = C*E*H**
Tax Impact		51	(120)	(247)	(141)	(47)	(23)	**L = J*F/(1-F)**
Revenue Requirements, Financing at WACC		**336**	**(793)**	**(1,614)**	**(927)**	**(308)**	**(150)**	**M = J+K+L**
Revenue Requirements, Financing at WACD		**230**	**(554)**	**(1,104)**	**(638)**	**(213)**	**(104)**	**N = C*H**
Revenue Requirements, Financing at ST Interest Rate		**96**	**(242)**	**(673)**	**(506)**	**(175)**	**(85)**	**P = C*I**

42.2 Please explain why two of the Deferral Accounts (Interest Expense Variance and Property Tax Variance) have a three year amortization while other variance accounts are amortized into rates in the following year.

Response:

FBC explained the rationale for the proposed amortization periods on its deferral accounts in the first round of information requests.

A three year amortization for the Interest Expense Variance Deferral Account was explained in part of the response to BCUC IR 1.190.6 which stated the following:

> *"A three year amortization term for the Interest Expense Variance deferral account is appropriate as it provides a reasonable balance between a long enough period to smooth the customer impact for any potential large variances that may arise in a given year, with a short enough period for which customers are still paying for the true cost of service in a timely manner. In addition, the amortization period is consistent with the Commission's approval of the three-year amortization term for FEI's Interest Variance deferral account."*

FBC explained the rationale for a three year amortization for the Property Tax Variance Deferral Account as part of the response to BCUC IR 1.191.4 which stated the following:

> *"A three year amortization term for the Property Tax Variance deferral account is appropriate as it provides a reasonable balance between a long enough period to smooth the customer impact for any potential large variances that may arise in a given year, with a short enough period for which customers are still paying for the true cost of service in a timely manner. In addition, the amortization period is consistent with the Commission's approval of the three-year amortization term for FEI's Property Tax Variance deferral account."*

Other deferral accounts identified in the response to BCUC IR 1.181.3 explained the rationale for amortization periods of three years or greater, while the response to BCUC IR 1.194.2 summarized the general principle around amortization periods which could be applied to those deferral accounts that are amortized in the following year, as follows:

> *"When considering the amortization period to be requested for a deferral account, FortisBC considers the size of the balance in the deferral account, the nature of the deferral, any applicable benefit period of the deferral, and the impact on customer rates in determining over how many years a deferral account balance should be amortized.*

This information is considered in the context of the overall rate increase for the test period."

42.3 Please confirm that all the first nine variance accounts listed can as easily be credit as well as debit balances, that is that they exist to capture variances between actual and forecast amounts, and the variances can be credit as well as debit.

Response:

The reference in the question to "Exhibit B-1 Section 4" is somewhat vague so it is not entirely clear which of "first nine variance accounts listed" is being referred to. Accordingly, FBC is assuming that the question is referencing the newly requested rate base deferral accounts requested under Section D4.3, beginning on page 262 of the 2014-2018 PBR Filing which include D4.3.2 Earnings Sharing Mechanism Deferral Account, D4.3.3 Generic Cost of Capital Revenue Requirements Impact, D4.3.4 Insurance Expense Variance deferral account, D4.3.5 Interest Expense Variance deferral account, D4.3.6 Tax Variance deferral account and the D4.3.7 Property Tax Variance deferral account.

FBC would agree that these six variance accounts could be either credit or debit balances as they exist to capture variances between actual and forecast amounts.

42.4 From a treasury management point of view does FortisBC's Treasury function seek to finance these balancing accounts with a combination of 30 year debt, common equity and bank borrowings?

Response:

Whether the variance deferral accounts balances referred to in the response to ICG IR 2.42.3 are initially recognized in rate base or not, they will be part of the regulated balance sheet financed collectively through a combination of long-term debt issuances, equity injections from FBC's parent company, short-term bank borrowings and funds generated by operating activities. These variance deferral accounts are currently forecast with nil amounts, however, when there are additions to these deferral accounts they will be funded through a combination of the previously mentioned debt and equity, consistent with any other item residing in rate base.

Attachment 21.4

Dennis Swanson
Director, Regulatory Affairs

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September 30, 2013

Via Email
Original via mail

Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Inc. Semi-Annual Demand Side Management Report for the Year ended June 30, 2013

Please find enclosed for filing FortisBC Inc.'s Semi-Annual Demand Side Management Report to June 30, 2013. Twelve copies will be couriered to the Commission.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson
Director, Regulatory Affairs

FortisBC Inc.

Semi-Annual DSM Report
Six Months Ended June 30, 2013

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REPORT OBJECTIVE

This report provides highlights of FortisBC Inc.'s (FBC or the Company) Demand Side Management (DSM) programs for the six month period ended June 30, 2013. The report reviews the progress of FBC's PowerSense program in meeting the approved DSM Plan and incenting FBC's customers to improve their energy efficiency. The report also provides information regarding integration and collaboration of the DSM programs with other BC Utilities[1]. A summary of PowerSense program activities in 2013 is also presented, with a comparison of actual energy savings and costs to Plan and provides a statement of financial results including benefit/cost ratios. Finally, a summary of historical FBC DSM costs and energy savings for the past five years is included in Appendix B.

OVERVIEW OF RESULTS FOR THE SIX MONTH PERIOD ENDED JUNE 30, 2013

Energy efficiency savings for the six month period ended June 30, 2013 were 11.6 GWh, or 73 percent of the 15.8 GWh Plan to June 30. Company costs incurred were $2,919,000 or 74 percent of the $3,939,000 Plan to June 30. Adding customer costs to the Company's program costs yields a Total Resource Cost (TRC) of $5,555,000 with an overall TRC benefit/cost ratio of 1.3. The method used to determine benefits is provided in the Financial Results section.

OVERVIEW OF PROGRAM ACTIVITIES

After bringing several new energy efficiency programs rapidly to market in 2012, the early part of 2013 was focused on refining those program offers and improving processes. Marketing and communication campaigns were also developed to better address specific target markets for both the residential and commercial sectors. To provide a more seamless and positive experience for customers seeking information and rebates for both natural gas and electricity measures, program and marketing integration continued with FBC Energy Utilities (FEU) EEC program. Operational efficiencies between the two companies were also sought.

RESIDENTIAL SECTOR

For the residential sector, PowerSense continued to work cooperatively with the Ministry of Energy and Mines (MEM), BC Hydro and FEU to provide a "one-stop shop" retro-fit rebate offer through the LiveSmart BC program. Although the MEM was not able to fund rebates in 2013, by focusing on the most cost-effective retro-fit measures and using a "whole house" approach, the utility partners continued to support the program with rebates for insulation and air sealing measures. The utility partners continued to collaborate on the evaluation of the 2009-2011 LiveSmart BC program and also had research conducted to develop a BC Home Energy Performance strategy and a BC Standards Guide for Air Sealing.

The residential Home Improvement and New Home programs' offers remained the same as 2012. However, marketing efforts were integrated with EEC natural gas rebate offers.

[1] British Columbia Utilities Commission (BCUC or the Commission) Order G-110-12, Directive 51.

Customers applying for both energy type rebates can access joint program information and experience a single application process[2]. The retail Appliance and Lighting Rebate programs and Heat Pump Maintenance programs continued to be popular. The Reduce Your Use program – rebates for home energy assessments for high-usage customers – was moderately successful with approximately 50 households receiving a full rebate on their home energy assessment.

A major advertising campaign to promote the On-Bill Financing program was launched in the spring. Despite the promotion, the program failed to garner much interest or participation. Feedback to MEM resulted in a change to the provincial regulation to loosen the eligibility requirements for the program.

The 2011-2012 Rossland Energy Diet pilot project's success in motivating customers to get home energy assessments and make energy efficiency improvements attracted national attention and resulted in funding from NRCan (Natural Resources Canada) and the Columbia Basin Trust to test the program's replicability and scalability. The Kootenay-region wide program for natural gas and electricity measures was launched in May and received immediate favourable responses. The intense "blitz" marketing campaign will continue to the end of the year. Planning for an Okanagan Energy Diet also started in late Q2.

The Low Income Direct Installation program for multi-family units continued from 2012. The common areas' lighting and control installations were completed in the Kootenays and household energy efficiency measures (low-flow shower heads, tap aerators and CFL lighting) were installed in-suite units. Planning for a Rental Direct Installation and Energy Assessment program commenced.

COMMERCIAL, INDUSTRIAL AND IRRIGATION SECTORS

In late 2012, PowerSense, in partnership with EEC, launched an on-line prescribed rebate program for business lighting, HVAC, refrigeration, commercial kitchen, natural gas boilers and hot water heaters. In 2013 program marketing started, which included sector specific advertising (i.e. commercial kitchens). The on-line application process was also improved. It was recognized that the lighting offer process needed to be amended to better meet customers' needs. Further customer research was conducted, which resulted in adding specific "point of sale" rebates at lighting wholesale businesses.

Although there were no changes to the Custom Business and Industrial Efficiency Program offers, the eligibility, application and approval processes were restructured and redesigned.

The PowerSense Irrigation program was structured in conjunction with the BC Farm Plan program, which lost funding in early 2013. During the redesign of the Irrigation Program, customers are able to access incentives through PowerSense's Custom Business Efficiency program.

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[2] Due to labour and other contractual agreements, the back-end application processing remained separate.

The FLIP Direct Install Lighting Program for small businesses wrapped up in March. The MEM jointly funded program was hugely successful, achieving 10 million kWh in savings over the 3 year program.

BEHAVIOURAL PROGRAMMING AND SUPPORTIVE INITIATIVES

PowerSense was able to integrate most aspects of its behavioural and educational programming with EEC's. PowerSense worked closely with the EEC outreach team and whenever appropriate, event sponsorship funding and outreach activities were shared. Similarly, PowerSense and EEC partnered to offer school educational programming: Destination Conservation, Beyond Recycling, Energy is Awesome, and the BC Lions Energy Champions are several of the educational programs supported.

PowerSense worked with EEC to help build a robust Contractor Ally program. The intent is to work collaboratively with local tradespeople and contractors so they can help promote energy efficiency and PowerSense's incentive programs. Opportunities for trades training and marketing are offered regularly through the Contractor Ally program.

POWERSENSE PROGRAMS OFFERED IN 2013

The following tables summarize the PowerSense program offerings and indicate program status and progress of integration with FEU's EEC programs.

Table 1 - Residential Programs 2013

Program and Measures	Status	Integrated with FortisBC Energy Utilities for combined offer
Energy Star Appliances	Ongoing	Yes[3] (clothes washers)
Energy Star Retail Lighting Rebate	Ongoing	No (electricity only)
Heat Pump (Air Source and Geo-Exchange)	Ongoing	No (electricity only)
TLC Heat Pump Maintenance	Ongoing	No (electricity only)
New Home	Ongoing	Yes (Marketing and Application Process)
Home Improvement (Retro-fit)	Ongoing	Yes (Marketing and Application Process)
LiveSmart BC (Retro-fit)	Ongoing	Yes
Reduce Your Use (energy assessments)	Ongoing	No (electricity only)
On-Bill Financing	Pilot Project	Yes
Low Income – Direct Installation Lighting	Completed	No (electricity only)

[3] Based on fuel source of hot water tank.

Program and Measures	Status	Integrated with FortisBC Energy Utilities for combined offer
Low Income – Direct Installation Household Measures	New	Yes
Low Income – Energy Savings Kits	Ongoing	In progress
Rental and Low-Income Housing	In-Design	Yes
Supporting Initiatives	Ongoing	Yes (where appropriate)
Contractor program	New	Yes (where appropriate)
WaterSavers (Tap by Tap)	Enhanced	Yes

Table 2 - Commercial and Industrial Programs 2013

Program and Measures	Status	Integrated with FortisBC Energy Utilities for combined offer
Product Rebate Program	Ongoing	Yes
FLIP – Direct Installation of Lighting for Small Business	Complete	No (electricity only)
Building Improvement – New	Ongoing	No
Building Improvement – Retro-fit	Ongoing	No
Building Optimization	Ongoing	Yes
Partners in Energy	Ongoing	No
Energy Efficiency Studies	Ongoing	In progress
Industrial Efficiency	Ongoing	No
Irrigation Pumping	New	No (electricity only)
Green Motors (motor rewinds)	Ongoing	No (electricity only)

ENERGY SAVINGS BY SECTOR

The energy savings that PowerSense achieved in the six month period ended June 30, 2013, are shown in the table below.

Table 3 - Energy Savings by Sector

SECTOR	Plan	Actual	% of Plan
	GWh		Achieved
Residential	8.5	6.7	79%
Commercial	6.0	4.3	72%
Industrial	1.3	0.6	46%
Total Savings (GWh)	**15.8**	**11.6**	**73%**

Overall, PowerSense achieved 73 percent of the Plan goal of 15.8 GWh savings to June 30. Residential and Commercial sector energy savings were below Plan at 79 and 72 percent of Plan savings. Industrial sector energy savings were under Plan at 46 percent. These results are discussed in more detail in the following sections.

DETAIL OF ENERGY SAVINGS

The following tables provide details on the DSM energy savings in each sector, including DSM activities in the service territories of the Municipal Wholesale customers.

Table 4 - Residential Energy Savings

RESIDENTIAL	Plan	Actual	% of Plan
	GWh		Achieved
Home Improvement Program	4.7	1.5	32%
Low Income	0.8	0.6	71%
Residential Lighting	1.2	2.8	227%
Heat Pumps	1.7	0.9	53%
New Home Program	0.05	0.9	1982%
Total Savings (GWh)	**8.5**	**6.7**	**79%**

Note: Minor differences due to rounding

In the six month period ended June 30, 2013, the energy saving results from Residential programs were 79 percent of Plan. The New Home and Residential Lighting programs exceeded Plan. The Heat Pump, Home Improvement and Low Income programs fell short of forecast. Customer (and builder) participation in the New Home program continues to exceed plan expectations. The point-of-purchase incentive campaign in March-April was effective and contributed to the success in Residential Lighting.

The LiveSmart BC collaboration resulted in 0.6 GWh of retrofit energy savings, which are recorded in the Heat Pump and Home Improvement (HIP) programs. The provincial incentives ended March 31, 2013, following in the steps of the federal government a year earlier, which likely was a factor in the reduced uptake in those programs.

In 2013, the Low Income program distributed approximately 140 Energy Saving Kits (ESKs) and the Kootenay phase of the direct install lighting program was completed. The ECAP[4] program did not launch in the first half of the year, resulting in fewer Low Income savings than Plan.

Table 5 - Commercial Energy Savings

COMMERCIAL	Plan	Actual	% of Plan
	GWh		Achieved
Lighting	3.7	3.8	102%
Building and Process Improvement	1.7	0.5	30%
Water Handling and Infrastructure	0.6	0.0	0%
Total Savings (GWh)	**6.0**	**4.3**	**72%**

Note: Minor differences due to rounding

The Commercial sector recorded savings of 4.3 GWh, or 72 percent of Plan to June 30. The majority of these savings were realized through the Commercial lighting programs, which include both "at the counter" product rebates and custom lighting retrofits, such as those installed at a supermarket in Nelson, producing 0.2 GWh of savings. Another component of the Commercial lighting programs was the FLIP direct installation program, a collaborative effort with the LiveSmart BC Business program. FLIP continued to be very popular until the program ended in the first quarter of 2013 and it contributed 1.8 GWh of savings.

An example of a Building and Process Improvement (BIP) project is a refrigeration upgrade at a supermarket in the Okanagan, contributing 0.15 GWh of savings. BIP results lagged as the Product Rebate portal, which enables customers to apply for prescriptive incentives on-line, was still ramping up in the first half of 2013.

As of June 30, 2013, there were no large water infrastructure projects, which generally occur less frequently than projects in other sectors. The pilot phase of the Irrigation program, which closed April 30, 2013, had a small number of applicants; however none of the applicants were eligible for incentives based on the upgrades proposed.

[4] Energy Conservation Assistance Program – targets low income owner occupied dwellings.

Table 6 - Industrial Energy Savings

INDUSTRIAL	Plan	Actual	% of Plan
	GWh		Achieved
Industrial Efficiency	1.1	0.6	52%
Integrated EMIS	0.1	0.0	0%
Total Savings (GWh)	**1.3**	**0.6**	**46%**

Note: Minor differences due to rounding

The Industrial Programs achieved savings of 0.6 GWh, or 46 percent of the 1.3 GWh Plan to June 30 as of result of an Industrial Efficiency project which involved the installation of variable speed drives on process equipment at a Kootenay lumber mill.

The table below disaggregates the Wholesale DSM savings, which are included in the sector tables above.

Table 7 - Wholesale Energy Savings by Municipality

WHOLESALE ACTIVITY	GWh	MW	% of GWh*
Penticton	0.6	0.1	39%
Summerland	0.2	0.1	13%
Grand Forks	0.1	0.01	5%
Nelson	0.6	0.1	42%
Total Savings (Wholesale)	**1.5**	**0.3**	**100%**

**Of savings attributable to the Wholesale class*

Note: Minor differences due to rounding.

The total Wholesale energy savings, which were acquired within the service areas of the four municipal electric utilities served by FBC, were 1.5 GWh and 0.3 MW in the first half of 2013. The largest DSM savings results occurred within Penticton and Nelson municipal utility service areas (the municipalities with the largest number of customers).

PROGRAM COSTS BY SECTOR

The table below presents the actual costs incurred in the six month period ended June 30, 2013, compared to the approved Plan. The percent of plan savings achieved is shown in the table for comparison purposes.

Table 8 - Costs by Sector

SECTOR/COMPONENT	Plan ($000s)	Actual ($000s)	% of Plan Costs	% of Plan Savings
Residential	1,972	1,179	60%	79%
Commercial	1,043	1,038	100%	72%
Industrial	182	76	42%	46%
Supporting Initiatives	363	307	85%	-
Monitoring & Evaluation	156	103	66%	-
Planning & Admin	224	217	97%	-
Total	**3,939**	**2,919**	**74%**	**73%**

Note: Minor differences due to rounding

Costs amounted to $2,919,000, or 74 percent of the 2013 Plan to June 30, commensurate with overall savings. Commercial Plan costs include proportionally higher fixed costs than Residential Plan costs, and as a result Commercial Plan costs are at 100 percent of Plan, despite lower Commercial Savings than plan to June 30. A breakdown of utility program costs per sector or program component follows. Appendix A contains an additional breakdown of total program costs, including the customer portion of project costs.

DETAIL OF COSTS

The following tables provide details on the DSM program costs for each sector and component in the PowerSense portfolio.

Table 9 - Residential Costs

RESIDENTIAL	Plan ($000s)	Actual ($000s)	% of Plan Achieved
Home Improvement Program	1,114	350	31%
Low Income	330	151	46%
Residential Lighting	157	243	155%
Heat Pumps	349	180	52%
New Home Program	23	255	1134%
Total	**1,972**	**1,179**	**60%**

Note: Minor differences due to rounding

The utility cost of Residential programs was $1,179,000, or 60 percent of Plan for the first half of 2013 largely due to the lower energy savings (32% of plan) in the Home Improvement program. The New Home program continues to be very successful and while the costs are over budget, they are commensurate with savings. The Low Income program was also underspent, since the Energy Conservation Assistance Program (ECAP) will not be launched until the second half of 2013.

Table 10 - Commercial Costs

COMMERCIAL	Plan	Actual	% of Plan Achieved
	($000s)		
Lighting	606	723	119%
Building and Process Improvement	348	307	88%
Water Handling and Infrastructure	89	8	9%
Total	**1,043**	**1,038**	**100%**

Commercial sector costs in the first half of 2013 amounted to $1,043,000 or close to 100 percent of Plan. The largest cost component of Commercial programs was the Lighting program, which includes incentives paid through the LiveSmart BC FLIP collaboration. The expenditures for Water Handling and Infrastructure are under budget, partially because it incorporates the Irrigation program. PowerSense launched the Irrigation program in June 2012, but had low uptake. In 2013 the program will be assessed to determine causes of low participation and the steps to be taken to improve it.

Table 11 - Industrial Costs

INDUSTRIAL	Plan	Actual	% of Plan Achieved
	($000s)		
Industrial Efficiency	162	72	45%
Integrated EMIS	21	3	17%
Total	**182**	**76**	**42%**

Note: Minor differences due to rounding

Industrial sector costs incurred by the Company were $76,000 for the period, or 42 percent of Plan. The Industrial sector is characterized by large projects that generally occur less frequently than in other sectors. Energy Management Information System (EMIS) software is a long-term program with up-front costs and savings that will be realized later in the process.

Portfolio level costs, which are not specifically associated with individual programs, include the following components: Supporting Initiatives, Monitoring and Evaluation, and Planning and Administration. These costs are summarized in the table below.

Table 12 - Portfolio Costs by Component

COMPONENTS	Plan	Actual	% of Plan Achieved
	($000s)		
Supporting Initiatives	363	307	85%
Monitoring & Evaluation	156	103	66%
Planning & Administration	224	217	97%
Total	**743**	**627**	**84%**

The Supporting Initiative costs for the first half of 2013 were $307,000 or 85 percent of the $363,000 Plan. Supporting Initiatives spending continues to drive community outreach and direct customer communication, which is a strong component of PowerSense programming. The three community ambassadors attended more than 85 community events in over 28 communities. Whenever possible, outreach and community event sponsorship was done in collaboration with EEC.

The Earth Hour promotion was expanded to included pledges from businesses in 2013, and was once again well received. As part of Earth Hour, customers across the FBC service area sent in approximately 1,500 pledges, each committing to turn their lights off for one hour. The majority of these customers also committed to at least one further action to reduce energy. Approximately 200 businesses pledged to turn their lights off for Earth Hour and 20 made commitments to take further action to reduce energy consumption.

The Planning and Evaluation budget is separated into two main components: Monitoring and Evaluation (M&E), and Planning and Administration. M&E was under budget with costs of $103,000, or 66 percent of Plan. The majority of expenses for M&E will be in the second half of 2013 as the main evaluation reports are completed. The Planning and Administration expenditure was $307,000, or 85 percent of Plan.

In Appendix A, Program Development costs are further broken out from the Planning and Administration costs.

FINANCIAL RESULTS

This section provides the financial and benefit/cost test results for the first half of 2013 and includes information about how the benefits were calculated for the total resource cost test (TRC) and for the modified total resource cost test (mTRC)[5].

The table below presents the financial and benefit cost tests by program. It also includes the Planning and Evaluation costs, which are allocated to the programs by savings achieved.

Table 13 - Financial Results for Six Month Period Ended June 30, 2013 by Program

Program	Program Benefits	Utility Program Costs	Planning & Evaluation Costs: Planning & Admin.	Monitoring & Eval.	Program Dev.	Customer Incurred Costs	Total Resource Costs	Benefits less Costs	Total Resource Benefit/Cost Ratio: TRC	mTRC
	($000s)									
Residential										
Home Improvement	1,360	350	23	13	5	567	958	402	1.4	1.5*
Low Income	197	151	8	5	2	35	201	(4)	1.0	1.3**
Residential Lighting	1,070	243	43	25	10	272	593	478	1.8	1.8
Heat Pumps	820	180	14	8	3	597	802	18	1.0	1.5*
New Home Program	994	255	14	8	3	261	541	452	1.8	1.8
Residential Total	**4,441**	**1,179**	**102**	**60**	**24**	**1,731**	**3,095**	**1,347**	**1.4**	**1.6**
Commercial										
Lighting	2,079	723	58	34	13	609	1,436	643	1.4	1.4
Building and Process Improvement	456	307	8	5	2	178	499	(43)	0.9	0.9
Water Handling Infrastructure	-	8	-	-	-	-	8	(8)	0.0	0.0
Commercial Total	**2,536**	**1,038**	**65**	**38**	**15**	**787**	**1,943**	**592**	**1.3**	**1.3**
Industrial										
Industrial Efficiency	336	72	9	5	2	118	206	130	1.6	1.6
Integrated EMIS	-	3	-	-	-	-	3	(3)	-	- *
Industrial Total	**336**	**76**	**9**	**5**	**2**	**118**	**210**	**126**	**1.6**	**1.6**
Supporting Initiatives		307					307		-	-
Total	**7,313**	**2,599**	**176**	**103**	**41**	**2,635**	**5,555**	**1,758**	**1.3**	**1.4**

Note: Minor differences due to rounding
** mTRC benefits used with some of program measures*
*** Low Income benefits increased by 30 percent*

An overall total resource benefit/cost ratio of 1.3 was achieved in the first half of 2013. The benefit/cost ratios for the individual programs are also detailed in the table above. The Residential sector program performance resulted in a benefit/cost ratio of 1.4, the Commercial sector achieved a benefit/cost ratio of 1.3 and the Industrial sector benefit/cost ratio was 1.6.

The Low Income program attained a benefit/cost ratio of 1.0, and with the 30 percent benefits lift as per the DSM Regulation, s4(2)(b), the benefit/cost ratio increased to 1.3.

Program benefits are primarily based on the present value of avoided power purchase costs. For the TRC test, the present value of avoided power purchase costs is calculated using the long-term avoided power purchase cost[6] over the measure lifespan, plus a deferred construction expenditure factor. Total resource costs shown are a total of Company costs and

[5] As described in the Demand Side Management Regulation (326/2008 as amended in December 2011) of the *Utilities Commission Act*.

[6] As per the 2012-2013 Long Term Demand Side Management (DSM) Plan, approved by BCUC Order G-110-12, the long-term avoided power purchase cost is $84.94/MWh.

customer costs. The customer portion of costs are the incremental costs of new construction measures and the energy efficiency "portion" of retrofit measure costs.

The estimated modified total resource benefit/cost ratio is also shown in the table above. The benefits used in the mTRC were estimated using a long-term avoided power purchase cost[7] plus a fifteen percent adder for non-energy benefits (NEB), as per the Company's interpretation of the DSM Regulation filed in the 2012 – 2013 Revenue Requirements Application[8] (2012-2013 RRA). The mTRC benefits were estimated based on the following measures that were subject to the mTRC in the 2012-2013 RRA:

- Residential:
    - Building Envelope – windows;
    - Heat Pumps – geo exchange, air source conversion, and ductless; and
    - Appliances – freezers.
- Industrial:
    - Integrated – EMIS.

The mTRC benefits estimation excludes the controls measure in the commercial lighting program, as it was not feasible to separate it from the other commercial lighting measures in the program results.

The mTRC does not differ substantially from the TRC results. Overall, the benefit/cost ratio increased from 1.3 to 1.4 using the prescribed mTRC method. The Residential benefit/cost ratio increased from 1.4 to 1.6. Most notably, the heat pump benefit/cost ratio increased from 1.0 to 1.5 with the use of the mTRC. Commercial and Industrial benefit/cost ratios were unaffected by incorporation of the mTRC.

The Company's DSM expenditure related to the measures that are subject to the mTRC was estimated to be $224,000 or 7.7 percent of the year-to-date DSM expenditure, which is within the regulated mTRC impact cap.

[7] As per the 2012-2013 Long Term Demand Side Management (DSM) Plan, approved by BCUC Order G-110-12, the long-term avoided power purchase cost is $111.96/MWh, for BC "clean" new resources.

[8] FBC 2012-2013 Revenue Requirements Application, Exhibit B-23, Oral Hearing Undertakings from March 8, 2012, Table 31-1.

ON-BILL FINANCING PILOT PROGRAM

The On-Bill Financing (OBF) pilot program, which is marketed as the Residential Energy Efficiency Loan Program, was mandated by the provincial government and provides loans of up to $10,000 to residential customers in the South Okanagan to make energy efficiency improvements to their homes. The loans are to be repaid on the customers' electricity bills over the next 10 years. This pilot program was launched on November 1, 2012 and will run until the end of 2014.

The OBF pilot program costs are separate from the DSM budget and in accordance with BCUC Order G-163-12, FBC created a non-rate base deferral account to capture the OBF pilot program costs. In the first half of 2013, the FBC portion of the OBF pilot program costs were $6,000.

APPENDIX A - DSM SUMMARY REPORT IN BCUC FORMAT

Table 14 - FBC Demand Side Management Summary Report for Six month period ended June 30, 2013

Sector/Program	Utility Program Costs			Planning and Evaluation			Total	Customer	Total			Benefit/Cost Ratios				
	Direct Incentives	Direct Information	Program Labour	Planning & Admin.	Monitoring & Eval.	Program Dev.	Utility Costs	Incurred Cost	Resource Cost	Program Benefits*	Energy Savings	Total Resource	Modified Total Resource	Rate Impact	Uility Cost	Levelised Cost
	($000s)										MWh					¢/kWh
Residential																
Home Improvements Program	169	57	124	23	13	5	391	567	958	1,360	1,499	1.4	1.5	0.7	3.5	6.4
Low Income	121	8	22	8	5	2	166	35	201	197	559	1.0	1.3	0.5	1.2	9.0
Residential Lighting	194	6	43	43	25	10	320	272	593	1,070	2,803	1.8	1.8	0.7	3.3	5.3
Heat Pumps	127	9	44	14	8	3	205	597	802	820	898	1.0	1.5	0.7	4.0	8.8
New Home Program	199	20	36	14	8	3	281	261	541	994	921	1.8	1.8	0.7	3.5	5.2
Residential Total	**810**	**100**	**269**	**102**	**60**	**24**	**1,364**	**1,731**	**3,095**	**4,441**	**6,680**	**1.4**	**1.6**	**0.7**	**3.3**	**6.5**
Commercial																
Lighting	476	33	213	58	34	13	827	609	1,436	2,079	3,783	1.4	1.4	0.6	2.5	5.0
Building and Process Improvement	145	20	143	8	5	2	321	178	499	456	523	0.9	0.9	0.6	1.4	9.7
Water Handling Infrastructure	-	2	6	-	-	-	8	-	8	-	-	0.0	0.0	0.0	0.0	-
Commercial Total	**621**	**55**	**362**	**65**	**38**	**15**	**1,157**	**787**	**1,943**	**2,536**	**4,306**	**1.3**	**1.3**	**0.6**	**2.2**	**5.8**
Industrial																
Industrial Efficiency	41	3	29	9	5	2	89	118	206	336	590	1.6	1.6	0.8	3.8	5.2
Integrated EMIS	-	-	3	-	-	-	3	-	3	-	-	0.0	0.0	0.0	0.0	-
Industrial Total	**41**	**3**	**32**	**9**	**5**	**2**	**92**	**118**	**210**	**336**	**590**	**1.6**	**1.6**	**0.8**	**3.6**	**5.3**
Supporting Initiatives	-	34	273	-	-	-	307	-	307			-	-	-		-
TOTAL	**1,472**	**191**	**936**	**176**	**103**	**41**	**2,919**	**2,635**	**5,555**	**7,313**	**11,576**	**1.3**	**1.4**	**0.7**	**2.5**	**6.5**

Note: Minor differences due to rounding

** Benefits calculated using the long-term avoided power purchase cost of $84.94/MWh.*

APPENDIX B - HISTORICAL SUMMARY OF FBC'S DSM COSTS AND ENERGY SAVINGS

Table 15 - Historical FBC DSM Costs and Energy Savings 2008- 2009

		1	2	3	4	5	6	7	8	9	10	11	12	13	14
		2008 (Actual)							2009 (Actual)						
		Spend ($000s)			Energy Savings (MWh)			TRC[3]	Spend ($000s)			Energy Savings (MWh)			TRC[3]
		Planned	Actual	Variance	Planned	Actual	Variance	(B/C)	Planned	Actual	Variance	Planned	Actual	Variance	(B/C)
1	**Residential**														
2	Home Improvements	135	62	73	385	331	(54)	0.8	273	145	128	1,024	1,032	8	1.4
3	Building Envelope[1]														
4	Heat Pumps	446	682	(236)	4,889	8,444	3,555	1.4	515	677	(162)	5,642	3,188	(2,454)	0.7
5	Residential Lighting	156	151	5	1,796	2,562	766	4.1	263	306	(44)	2,822	3,349	526	2.8
6	New Home Program	286	340	(54)	1,332	1,596	265	2.8	341	496	(155)	1,216	1,735	518	2.2
7	Appliances[1]														
8	Electronics[1]														
9	Water Heating[1]														
10	Low Income[1]														
11	Behavioural[1]														
12	*Residential Total*	**1,023**	**1,236**	**(213)**	**8,401**	**12,933**	**4,531**	**1.7**	**1,391**	**1,624**	**(233)**	**10,705**	**9,304**	**(1,401)**	**1.3**
13	**Commercial**														
14	Lighting	257	375	(118)	3,000	5,960	2,960	2.4	724	422	302	5,505	7,638	2,133	3.0
15	Building and Process Improvements	497	506	(9)	6,103	5,081	(1,022)	1.6	563	639	(75)	6,095	8,713	2,618	1.8
16	Computers														
17	Municipal (Water Handling)[2]														
18	Irrigation[2]														
19	*Commercial Total*	**754**	**881**	**(127)**	**9,103**	**11,042**	**1,939**	**1.9**	**1,287**	**1,060**	**227**	**11,600**	**16,351**	**4,751**	**2.2**
20	**Industrial**														
21	Compressed Air	58	22	36	700	210	(490)	1.2	71	41	30	811	398	(413)	0.9
23	EMIS														
22	Industrial Efficiencies	142	124	18	1,285	3,083	1,798	2.3	274	195	79	2,189	2,305	116	1.6
24	*Industrial Total*	**200**	**147**	**53**	**1,985**	**3,294**	**1,309**	**2.3**	**345**	**236**	**109**	**3,000**	**2,703**	**(297)**	**1.5**
25	**Programs Total**	**1,977**	**2,264**	**(287)**	**19,489**	**27,268**	**7,779**	**-**	**3,023**	**2,920**	**103**	**25,305**	**28,358**	**3,053**	**-**
26	Supporting Initiatives	-	-	-	-	-	-	-	141	141	0	-	-	-	-
27	Planning & Evaluation	378	419	(41)	-	-	-	-	503	402	101	-	-	-	-
28	**Total**	**2,355**	**2,683**	**(328)**	**19,489**	**27,268**	**7,779**	**1.8**	**3,667**	**3,464**	**204**	**25,305**	**28,358**	**3,053**	**1.7**

[1] These programs were included in Home Improvements program

[2] Water Treatment and Wastewater Handling infrastructure were part of Building and Process Improvement

[3] Benefits calculated using RS3808 applicable at the time

Table 16 - Historical FBC DSM Costs and Energy Savings 2010

		1	2	3	4	5	6	7
		2010 (Actual)						
		Spend ($000s)			Energy Savings (MWh)			TRC³
		Planned	Actual	Variance	Planned	Actual	Variance	(B/C)
1	**Residential**							
2	Home Improvements	294	434	(140)	953	4,948	3,995	3.1
3	Building Envelope¹							
4	Heat Pumps	624	749	(125)	6,377	3,239	(3,138)	1.2
5	Residential Lighting	243	278	(35)	2,383	2,589	206	2.4
6	New Home Program	254	247	7	1,392	477	(915)	1.1
7	Appliances¹							
8	Electronics¹							
9	Water Heating¹							
10	Low Income¹	100	131	(31)	1,000	385	615	0.7
11	Behavioural¹							
12	*Residential Total*	**1,515**	**1,838**	**(323)**	**12,105**	**11,638**	**764**	**1.9**
13	**Commercial**							
14	Lighting	722	526	196	5,304	7,971	2,667	3.5
15	Building and Process Improvements	658	597	61	6,751	6,685	(67)	1.5
16	Computers							
17	Municipal (Water Handling)²							
18	Irrigation²							
19	*Commercial Total*	**1,380**	**1,123**	**257**	**12,055**	**14,655**	**2,600**	**2.1**
20	**Industrial**							
21	Compressed Air	87	25	62	938	114	(823)	0.7
23	EMIS							
22	Industrial Efficiencies	302	216	86	2,412	2,853	441	2.1
24	*Industrial Total*	**389**	**241**	**148**	**3,350**	**2,967**	**(383)**	**2.0**
25	**Programs Total**	**3,284**	**3,203**	**81**	**27,510**	**29,261**	**2,981**	**2.1**
26	Supporting Initiatives	148	155	(7)	-	-	-	
27	Planning & Evaluation	519	354	165	-	-	-	-
28	**Total**	**3,951**	**3,712**	**239**	**27,510**	**29,261**	**2,981**	**2.0**

¹ These programs were included in Home Improvements program

² Water Treatment and Wastewater Handling infrastructure were part of Building and Process Improvement

³ Benefits calculated using RS3808 applicable at the time

Table 17 - Historical FBC DSM Costs and Energy Savings 2011-2012

		1	2	3	4	5	6	7	8	9	10	11	12	13	14
		2011 (Actual)							2012 (Actual)						
		Spend ($000s)			Energy Savings (MWh)			TRC[3]	Spend ($000s)			Energy Savings (MWh)			TRC
		Planned	Actual	Variance	Planned	Actual	Variance	(B/C)	Planned	Actual	Variance	Planned	Actual	Variance	(B/C)
1	**Residential**														
2	Home Improvements	2,145	479	1,666	8,960	3,692	(5,268)	1.6	1,719	637	1,082	7,620	4,656	(2,964)	1.7
3	Building Envelope[1]														
4	Heat Pumps	694	532	162	3,397	2,257	(1,140)	1.0	703	636	67	3,397	2,161	(1,236)	1.0
5	Residential Lighting	438	239	199	3,420	3,308	(112)	2.2	328	337	(9)	2,530	2,599	69	1.8
6	New Home Program	54	205	(151)	105	689	584	1.0	43	314	(271)	90	1,040	950	1.4
7	Appliances[1]								247	332	(85)	690	1,248	558	
8	Electronics[1]														
9	Water Heating[1]														
10	Low Income	305	245	60	540	1,447	(907)	1.0	677	308	369	1,774	1,054	(720)	1.3
11	Behavioural[1]														
12	*Residential Total*	**3,636**	**1,700**	**1,936**	**16,422**	**11,393**	**(6,843)**	**1.3**	**3,717**	**2,564**	**1,153**	**16,101**	**12,758**	**(3,343)**	**1.5**
13	**Commercial**														
14	Lighting	1,114	1,995	(881)	7,370	20,577	13,207	2.3	1,157	2,152	(995)	7,390	14,256	6,866	2.2
15	Building and Process Improvements	572	606	(34)	3,010	1,386	(1,624)	0.7	659	612	47	3,410	1,959	(1,451)	1.3
16	Computers														
17	Municipal (Water Handling)	432	231	201	3,560	2,199	(1,361)	1.6	383	255	128	2,580	1,677	(903)	2.6
18	Irrigation[2]														
19	*Commercial Total*	**2,118**	**2,832**	**(714)**	**13,940**	**24,162**	**10,222**	**1.9**	**2,199**	**3,019**	**(820)**	**13,380**	**17,892**	**4,512**	**2.0**
20	**Industrial**														
21	Compressed Air														
23	EMIS	10	9	1	80	-	(80)	-	27	10	17	190	-	(190)	2.0
22	Industrial Efficiencies	603	128	475	9,280	794	(8,486)	2.5	323	163	160	2,290	937	(1,353)	-
24	*Industrial Total*	**613**	**137**	**476**	**9,360**	**794**	**(8,566)**	**2.4**	**350**	**173**	**177**	**2,480**	**937**	**(1,543)**	**1.9**
25	**Programs Total**	**6,367**	**4,669**	**1,698**	**39,722**	**36,349**	**(5,187)**	**1.8**	**6,266**	**5,756**	**510**	**31,961**	**31,587**	**(374)**	**1.8**
26	Supporting Initiatives	725	658	67	-	-	-	-	725	816	(91)	-	-	-	-
27	Planning & Evaluation	750	590	160	-	-	-	-	740	728	12	-	-	-	-
28	**Total**	**7,842**	**5,918**	**1,924**	**39,722**	**36,349**	**(5,187)**	**1.6**	**7,731**	**7,300**	**431**	**31,961**	**31,587**	**(374)**	**1.6**

[1] These programs were included in Home Improvements program

[2] Irrigation was included in Municipal (Water Handling)

[3] Benefits calculated using RS3808 applicable at the time

Attachment 24.2

Argus US Electricity

Incorporating the Energy Market Report

argusmedia.com

Power Market Prices and Analysis | Issue 13-177 | 13 September 2013

Day-ahead peak prices

Trade date 13-Sep-13

	$/MWh	Price*	Change	Low	High	MW	Trades
East	NY G	42.00	0.50	41.50	42.50	-	-
	PJM W	38.00	1.50	37.50	38.50	-	-
	NE Pool	41.50	3.75	41.00	42.00	-	-
ERCOT	Houston	38.00	-4.50	37.50	38.50	-	-
	North	37.50	-6.75	37.50	37.50	1,050	6
	South	37.00	-5.25	36.50	37.50	-	-
	West	38.00	-6.25	37.50	38.50	-	-
Midwest	Indiana	31.00	0.50	30.50	31.50	-	-
	N. Ill.	32.75	4.00	32.25	33.25	-	-
	PJM AD	30.75	1.75	30.25	31.25	-	-
Southeast	Entergy	32.50	3.50	32.00	33.00	-	-
	Southern	34.76	0.26	34.50	35.00	415	4
West	COB	36.55	-4.29	36.00	36.75	125	4
	Four Corners	38.75	2.75	38.25	39.25	-	-
	Mead	38.75	-0.78	38.25	39.25	-	-
	Mid-C	34.04	-5.11	32.00	35.00	1,350	53
	Mona	32.00	-7.50	31.50	32.50	-	-
	NP 15	45.00	-0.50	44.50	45.50	-	-
	Palo Verde	37.11	1.50	36.25	38.00	450	16
	SP 15	48.78	2.28	48.75	48.85	100	4

Day-ahead off-peak prices

Trade date 13-Sep-13

	$/MWh	Price*	Change	Low	High	Volume	Trades
East	NY G	30.00	-3.75	29.50	30.50	-	-
	PJM W	25.50	-1.50	25.00	26.00	-	-
	NE Pool	29.50	0.25	29.00	30.00	-	-
ERCOT	Houston	24.75	-0.50	24.25	25.25	-	-
	North	24.75	-1.00	24.25	25.25	-	-
	South	24.50	-0.50	24.00	25.00	-	-
	West	25.25	0.00	24.75	25.75	-	-
Midwest	Indiana	20.50	-2.00	20.00	21.00	-	-
	N. Ill.	19.00	-1.75	18.50	19.50	-	-
	PJM AD	22.00	-3.00	21.50	22.50	-	-
Southeast	Entergy	21.50	1.25	21.00	22.00	-	-
	Southern	24.00	3.25	23.50	24.50	-	-
West	COB	29.95	1.29	29.50	30.00	250	7
	Four Corners	30.00	5.00	29.50	30.50	-	-
	Mead	31.00	3.75	30.50	31.50	-	-
	Mid-C	29.00	0.51	28.50	29.50	-	-
	Mona	25.00	2.00	24.50	25.50	-	-
	NP 15	34.00	0.50	33.50	34.50	-	-
	Palo Verde	30.50	5.25	30.00	31.00	-	-
	SP 15	39.25	6.25	38.75	39.75	-	-

* When MW and trade number are blank, the low/high/price represent bid/ask/assessment. When MW and trade number have values, low/high/price represent low trade, high trade and volume-weighted average

News

East

Peak prescheduled dailies in **PJM West added 4.1pc** to $38/MWh for 16 September. New England settled at $41.50, up 9.9pc. Buyers appeared to cover weekend uncertainty, and not a return to cooling loads next week.

Continued on page 2

Midwest

Indiana peak packages prescheduled for 16 September delivery ticked slightly higher today, despite a bearish weather and demand outlook next week. ***Argus* assessed Indiana peak at $31/MWh today, up 50¢ on the day.**

Continued on page 5

West

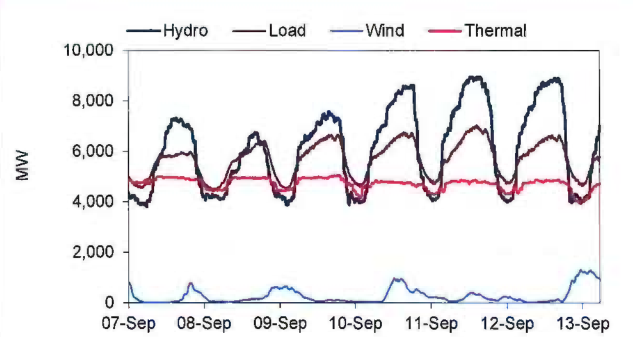
Mid-Columbia peak for 16 September was deeply discounted today as AC and DC paths into California were cut and temperatures fall along the west coast. The Mid-C to SP-15 spread jumped to 43pc today.

Continued on page 9

ERCOT

Texas peak preschedules for 16 September fell today following a rally in prices that began mid-last week amid hot fall weather. Houston and Dallas area temperatures look slightly lower early next week, with demand declines.

BPA wind vs loads



Inside

East Markets

Continued from page 1

- **Peak dailies in PJM West averaged $66.50 this week, up 72pc.** The off-peak average added 14pc to $28.90. Temperatures next week are forecast lower, suggesting lower loads and prices and possibly some heating demand at night.

- Peak day-ahead prices in PJM West averaged $55.44 for 1-12 September, up 25pc from the same period last year. The average is **skewed by the hot weather of 10 September.** The off-peak average added 16pc to $27.41.

- The day-ahead natural gas spark spread in PJM West for 1-12 September was $26.02, up 27pc from the same period last year. However, the dark spread more than doubled to $28.99, meaning that it is **increasingly profitable to run coal-fired generators.** That has been the case every month so far this year.

- Weather in the east was moderate today and loads and prices are consequently lower. Prices in New England in the early afternoon were in the $40s after hitting $58 between 10am and 11am. For most of the day, the actual load in the region was above what the Independent System Operator (ISO) was expecting. The difference was more than 600MW at 2pm. Unlike yesterday, **today the grid operator did not call on oil-fired generators**, and coal was just 2pm of the fuel mix.

- New England is expecting a peak load of 18,160MW today and an average of 14,920MW over the weekend. That is **0.4pc above the average of the prior weekend.**

- **The weekend peak load in New York will average 17,990MW.** The average in New York City will be 6,027MW, compared with 2,679MW on Long Island and 1,324MW in the Capital region.

Market-implied heat rates and spark spreads

		Heat rate	Spark spreads in 000 Btu/kWh at heating efficiencies of:					
		(Btu/kWh)	7	8	10	12	15	18
Peak	NYISO G	10,370	13.65	9.60	1.50	-6.60	-18.75	-30.90
	PJM West	10,659	13.05	9.48	2.35	-4.78	-15.48	-26.17
	NE Pool	11,464	16.16	12.54	5.30	-1.94	-12.80	-23.66
	Southern	9,382	8.82	5.12	-2.29	-9.70	-20.82	-31.93
Off-peak	NYISO G	7,407	1.65	-2.40	-10.50	-18.60	-30.75	-42.90
	PJM West	7,153	0.55	-3.02	-10.15	-17.28	-27.98	-38.67
	NE Pool	8,149	4.16	0.54	-6.70	-13.94	-24.80	-35.66
	Southern	6,478	-1.94	-5.64	-13.05	-20.46	-31.58	-42.69

Forward markets $/MWh

	PJM West				NEPOOL			New York A			New York G			New York J		
	Peak			Off-Peak	Peak		Off-Peak	Peak		Off-Peak	Peak		Off-Peak	Peak		Off-Peak
	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price
Oct-13	41.50	16.36	15.01	31.18	40.65	14.21	31.10	38.00	7.77	30.55	45.23	18.76	34.60	47.60	21.79	35.60
Nov-13	41.55	15.51	14.90	32.13	48.03	13.18	36.95	38.00	9.48	32.05	48.00	13.18	37.80	50.20	22.67	38.80
Dec-13	42.85	13.80	17.43	34.00	74.95	15.72	59.00	41.18	12.54	34.35	59.55	0.32	47.20	60.80	24.09	48.25
Jan-14	46.30	14.12	20.22	36.20	98.15	14.93	76.55	44.80	16.12	36.55	70.70	-12.52	51.90	73.30	30.99	54.75
Feb-14	43.90	13.02	18.34	35.75	95.55	18.40	73.70	44.30	15.58	36.15	70.30	-6.85	51.25	74.40	34.49	54.10
Mar-14	42.65	15.91	16.83	31.95	55.83	13.93	39.75	36.70	8.14	31.15	46.05	4.18	37.45	48.05	19.06	38.20
Q4-13	41.95	15.21	15.76	32.48	54.20	14.03	42.68	39.05	9.93	32.38	50.78	10.63	40.03	52.75	22.73	41.05
Win-14	45.15	13.62	19.33	36.00	96.90	16.72	75.20	44.55	15.85	36.35	70.50	-9.69	51.60	73.80	32.69	54.45
Spr-14	41.98	15.93	16.19	31.48	49.03	13.22	36.43	36.43	8.63	30.65	45.35	9.57	36.50	47.35	19.94	37.25
Sum-14	54.45	27.49	27.20	31.30	53.50	23.32	35.45	49.85	22.19	31.90	61.25	31.07	38.40	66.40	39.14	40.40
Q4-14	40.93	13.64	14.84	31.45	56.68	13.39	43.85	38.20	9.28	31.15	49.10	5.84	36.60	51.65	22.83	38.25
Win-15	45.15	12.67	18.68	35.70	98.50	16.71	71.30	45.05	14.70	36.85	63.70	-18.09	47.85	66.45	27.06	49.80
Spr-15	41.45	14.25	15.09	31.50	48.70	11.46	38.13	39.55	10.75	30.85	47.45	10.21	35.65	50.35	22.28	37.65
Sum-15	56.40	28.62	28.55	32.10	53.45	22.47	35.50	44.50	16.07	32.15	58.90	27.92	40.60	65.70	37.72	44.00
Cal-14	44.65	17.90	18.39	31.50	58.00	15.96	43.20	41.10	13.04	31.35	53.45	11.41	38.45	56.65	27.25	39.95
Cal-15	44.90	17.26	18.02	31.60	57.90	14.97	43.40	41.10	12.20	31.35	52.55	9.62	38.55	56.20	26.63	40.95
Cal-16	45.50	17.04	17.57	32.20	55.45	13.72	40.85	41.35	11.89	31.85	53.25	11.52	39.25	57.35	27.53	42.10
Cal-17	46.25	16.56	17.68	33.25	53.10	14.44	40.25	42.40	11.86	32.33	56.05	17.39	39.85	57.75	27.35	43.00

East Markets

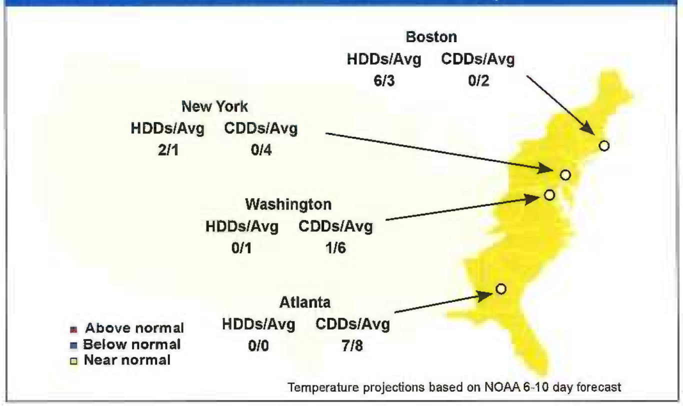
Spot natural gas in $/mmBtu

Location	Average	Low	High
Col Gas Appalachia	3.650	3.620	3.760
Dominion South Point	3.310	3.250	3.390
Florida Gas, zone 3	3.650	3.625	3.680
Texas Eastern zone M3	3.565	3.540	3.640
Transco zone 4	3.605	3.575	3.660
Transco zone 6 NY	3.720	3.680	3.860

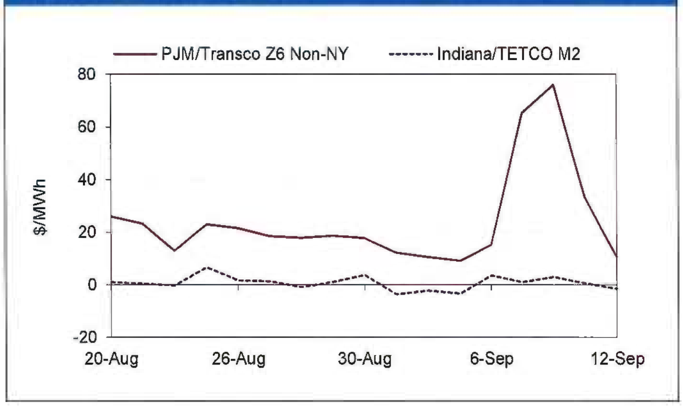
Forward natural gas in $/mmBtu

Location	October	Nov 2013-Mar 2014	Apr 2014-Oct 2014
Columbia Gas App.	3.647	3.732	3.760
Dominion South Pt.	3.412	3.556	3.760
Florida Gas Zone 3	3.765	3.828	4.119
Texas Eastern M-3	3.592	4.000	3.548
Transco Zone 4	3.668	3.795	3.952
Transco Zone 6 NY	3.687	4.873	3.692

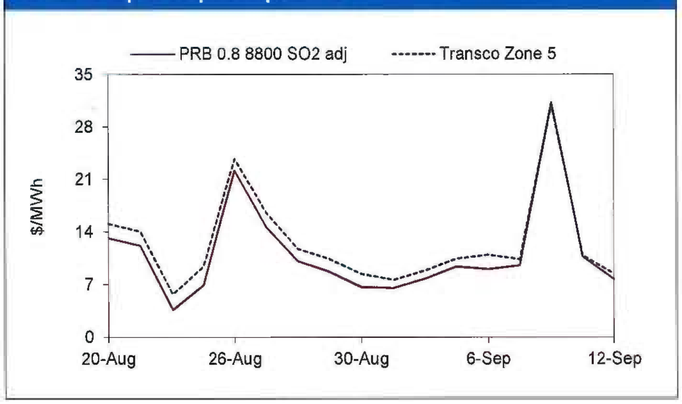
Degree days outlook vs temperature: 19-Sep



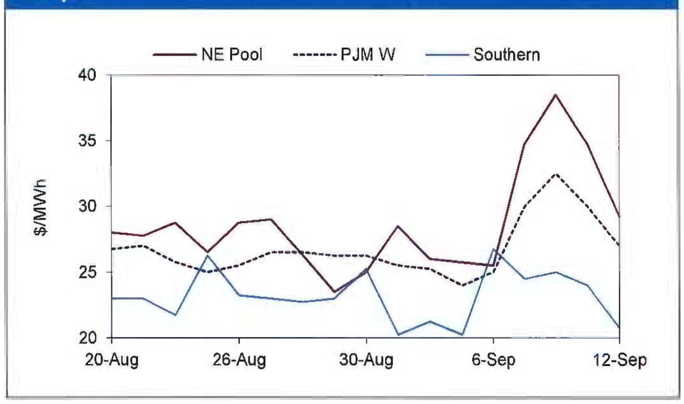
Implied gas spark spreads



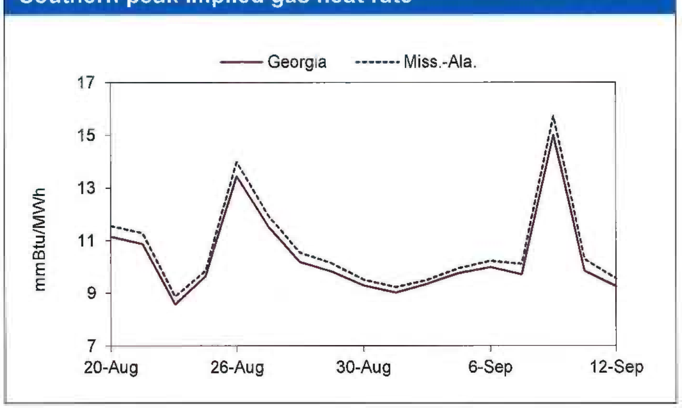
Southern peak spark spreads



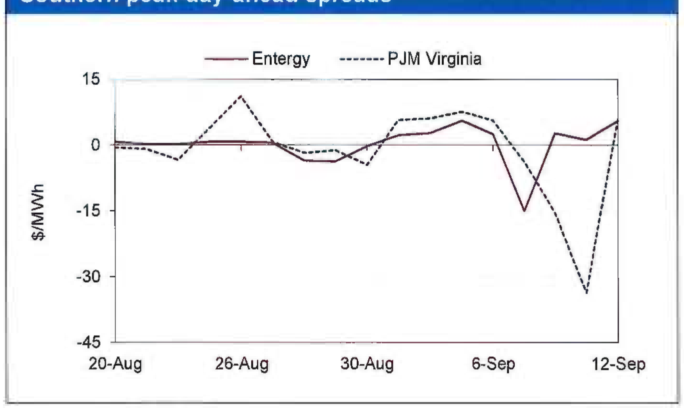
Off-peak



Southern peak implied gas heat rate



Southern peak day-ahead spreads



East Prices at a Glance — $/MWh

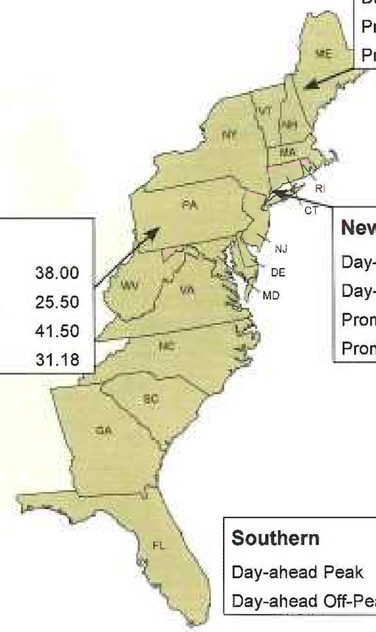
Day-ahead markets for 13-Sep-13

New England	
Day-ahead Peak	41.50
Day-ahead Off-Peak	29.50
Prompt Peak	40.65
Prompt Off-Peak	31.10

New York zone G	
Day-ahead Peak	42.00
Day-ahead Off-Peak	30.00
Prompt Peak	45.23
Prompt Off-Peak	34.60

PJM West	
Day-ahead Peak	38.00
Day-ahead Off-Peak	25.50
Prompt Peak	41.50
Prompt Off-Peak	31.18

Southern	
Day-ahead Peak	34.76
Day-ahead Off-Peak	24.00



Day-ahead minus hourly spread

12-Sep-13	Peak	Off-Peak
ISO NE		
Internal Hub	38.43	1.12
Phase I/II	16.68	1.02
NY ISO		
Zone A	16.18	-0.29
Zone G	18.85	0.45
Zone J	19.00	-2.31
Cross Sound	24.26	-0.14
PJM		
PJM Western Hub	11.28	-0.36
PJM Eastern Hub	19.33	1.48
PJM Dominion Hub	15.05	4.44
PJM New Jersey Hub	10.39	-20.99

Hourly price averages

	Peak		Off-peak	
	12-Sep-13	11-Sep-13	12-Sep-13	11-Sep-13
ISO NE				
Internal Hub	50.67	192.87	33.67	32.70
Phase I/II	49.11	187.10	32.76	31.92
NY ISO				
Zone A	33.12	224.30	36.73	41.25
Zone G	63.15	222.35	40.80	45.71
Zone J	68.39	223.22	43.65	46.27
Cross Sound	47.59	143.94	40.10	44.48
PJM				
PJM Western Hub	48.72	109.00	30.36	33.60
PJM Eastern Hub	48.74	104.87	30.13	34.45
PJM Dominion Hub	55.96	93.86	32.55	37.44
PJM New Jersey Hub	60.35	153.80	52.78	39.12

Emissions-adjusted dark spreads

	Peak	Off-peak	24-hour
Nepool	18.12	6.12	14.12
New York G	8.55	-3.45	4.55
PJM West	13.67	1.17	9.50
Southern	1.18	-9.58	-2.40

Note: Dark spreads are derived first by determining the value for a representative mix of coals and their transportation to the power hub. After adjusting for the amount of sulfur output from that proportionate coal mix in the production of a megawatt hour, the value of SO_2 allowances under current regulations is added to the cost of generation (heat rate 10 mmBtu/MWh x mmBtu value of the coal). This cost of generation is subtracted from the day's power hub clearing price, which is either the *Argus* index or assessment.

Day-ahead peak spreads

	New England	NY G	PJM West	Indiana	AEP Dayton	Northern Ill	Southern
New England	—	-0.50	3.50	10.50	10.75	8.75	6.74
NY G	0.50	—	4.00	11.00	11.25	9.25	7.24
PJM West	-3.50	-4.00	—	7.00	7.25	5.25	3.24
Indiana	-10.50	-11.00	-7.00	—	0.25	-1.75	-3.76
AEP Dayton	-10.75	-11.25	-7.25	-0.25	—	-2.00	-4.01
Northern Ill	-8.75	-9.25	-5.25	1.75	2.00	—	-2.01
Southern	-6.74	-7.24	-3.24	3.76	4.01	2.01	—

Sources: ISOs, Argus assessments

Midwest Markets

Continued from page 1

- Early-week heat in the mid-Atlantic caused PJM peak loads and next-day prices to rise sharply for 9-13 September flows, increasing the value of wheels from the midwest as well. **AEP-Dayton peak rose 53pc to a weekly average of $52.50.** Off-peak was up 12pc to $27.55. Indiana peak rose 34pc to$47.20.

- **Calendar 2015 power is undervalued** by about $2/MWh in PJM West and about $4/MWh at the Northern Illinois hub, an Exelon executive told investors this week, so the company has not sold forward as much as in the past. The utility normally hedges a third of output on a forward basis each year. But William Von Hoene, senior executive vice president, told a Barclays energy-power conference that the strategy is currently "behind rateable to take advantage of our market view." Exelon expects to benefit from coal plant retirements and other fundamental changes in PJM that will result in rising prices over the next two years.

- Cooling loads backed down enough to send prices lower in Texas this week. Prescheduled peak blocks at the Electric Reliability Council of Texas (ERCOT) South hub averaged $41.60/MWh for 9-13 September flows, down 8pc week to week. North slipped 5pc to $41.81. **West blocks retained a slight premium to the other hubs.** Wind output this week was about one-third of where it is in the spring.

- **Demand forecasts from ERCOT for early next week are significantly lower** than what was recorded in the grid operator footprint this week. Dallas and Houston are likely to cool a few degrees. The grid operator is calling for peak of 55,782MW on 16 September.

Market-implied heat rates and spark spreads

		Heat rate	Spark spreads in 000 Btu/kWh at heating efficiencies of:					
		(Btu/kWh)	7	8	10	12	15	18
Peak	Indiana	9,185	7.38	4.00	-2.75	-9.50	-19.63	-29.75
	N. Ill.	8,863	6.88	3.19	-4.20	-11.59	-22.68	-33.76
	PJM AD	8,448	5.27	1.63	-5.65	-12.93	-23.85	-34.77
	Entergy	9,015	7.27	3.66	-3.55	-10.76	-21.58	-32.39
Off-peak	Indiana	6,074	-3.13	-6.50	-13.25	-20.00	-30.13	-40.25
	N. Ill.	5,142	-6.87	-10.56	-17.95	-25.34	-36.43	-47.51
	PJM AD	6,044	-3.48	-7.12	-14.40	-21.68	-32.60	-43.52
	Entergy	5,964	-3.74	-7.34	-14.55	-21.76	-32.58	-43.39

Forward markets $/MWh

	Indiana				Northern Illinois				PJM AD				ERCOT North			
	Peak			Off-Peak	Peak			Off-Peak	Peak			Off-Peak	Peak			Off-Peak
	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price
Oct-13	34.63	9.12	5.19	26.85	34.50	7.78	15.01	22.65	37.90	12.37	11.41	29.50	34.10	8.92	9.61	25.75
Nov-13	34.60	8.60	5.15	26.50	35.35	8.23	15.66	23.50	38.15	12.15	11.50	30.18	33.55	7.98	8.86	26.80
Dec-13	35.25	8.29	13.50	27.18	35.95	7.97	16.21	25.75	39.18	12.19	20.88	31.18	34.35	7.70	9.46	28.30
Jan-14	38.75	11.12	16.68	27.95	38.00	9.31	17.84	28.85	42.10	14.47	23.60	33.05	37.25	10.01	12.91	29.95
Feb-14	36.10	8.48	14.25	27.30	37.40	8.83	17.44	28.20	39.40	11.78	21.09	32.35	38.20	10.96	13.11	30.35
Mar-14	35.40	8.10	12.44	26.75	35.95	7.74	15.59	24.95	38.80	11.50	19.55	30.15	39.10	12.22	13.26	29.80
Q4-13	34.83	8.68	7.95	26.83	35.23	7.98	15.59	24.00	38.40	12.23	14.59	30.30	34.03	8.20	9.33	26.98
Win-14	37.50	9.88	15.54	27.65	37.70	9.07	17.64	28.55	40.80	13.18	22.39	32.70	37.70	10.46	12.99	30.15
Spr-14	35.30	8.28	12.62	26.15	35.35	7.76	14.98	24.45	38.28	11.28	19.30	29.55	38.45	11.91	13.14	29.40
Sum-14	44.15	17.84	20.76	26.20	46.10	18.63	25.08	25.30	48.65	22.34	29.36	28.45	83.35	56.20	57.54	34.60
Q4-14	34.90	7.62	12.37	26.60	34.18	5.52	13.87	22.55	37.40	10.12	18.57	29.20	37.80	10.08	12.58	29.65
Win-15	37.95	9.16	15.06	27.90	37.35	7.27	16.44	29.60	41.20	12.41	22.10	31.75	42.85	13.73	17.30	33.00
Spr-15	35.55	7.79	11.99	25.80	35.50	7.03	14.33	23.05	38.50	10.74	18.87	29.45	42.20	14.40	16.10	31.50
Sum-15	47.25	20.83	22.93	26.75	50.05	22.51	28.17	25.90	50.95	24.53	30.97	29.85	96.60	68.69	69.96	37.05
Cal-14	37.25	10.38	14.54	26.15	37.50	9.59	17.11	24.30	40.45	13.58	21.52	29.15	47.38	20.28	22.09	30.45
Cal-15	37.80	10.41	14.16	26.00	38.15	9.77	16.93	24.30	41.15	13.76	21.54	29.20	52.00	23.90	25.90	32.05
Cal-16	38.70	10.58	13.91	27.45	38.70	9.95	16.74	26.20	41.35	13.23	21.13	30.75	51.20	22.39	24.43	31.83
Cal-17	39.90	11.20	14.11	28.03	39.25	9.67	16.31	28.18	42.50	13.80	21.51	32.65	49.05	19.49	21.31	31.10

Midwest Markets

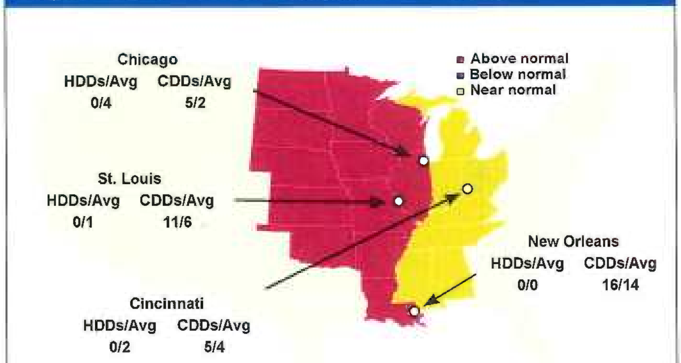
Spot natural gas in $/mmBtu

Location	Average	Low	High
CenterPoint	3.550	3.500	3.580
Chicago Citygates	3.695	3.650	3.770
Mich Con Citygates	3.830	3.815	3.855
NGPL Texok Zone	3.600	3.570	3.670
NNG Ventura	3.645	3.610	3.705
Panhandle OK Mainline	3.395	3.380	3.500

Forward natural gas in $/mmBtu

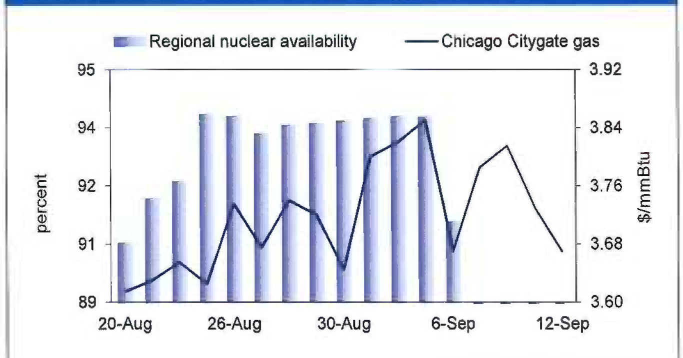
Location	October	Nov 2013-Mar 2014	Apr 2014-Oct 2014
CenterPoint	3.559	3.626	3.757
Chicago Citygates	3.817	3.877	3.907
MichCon Citygate	3.895	3.887	3.951
NGPL Texok Zone	3.652	3.689	3.822
NNG Ventura	3.772	3.801	3.818
Panhandle OK Mainline	3.457	3.566	3.587

Degree days outlook vs temperature: 19-Sep



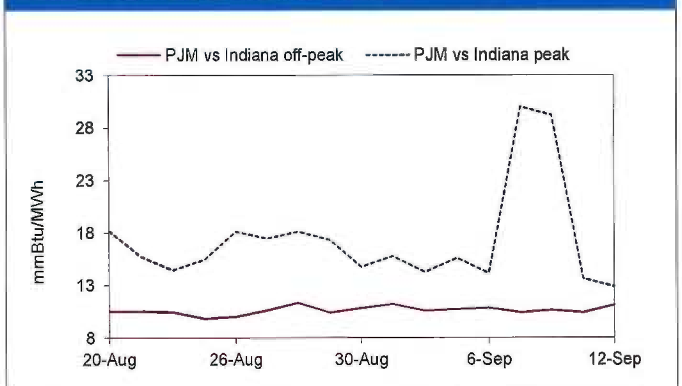
Temperature projections based on NOAA 6-10 day forecast

Nuclear availability vs Chicago Citygates

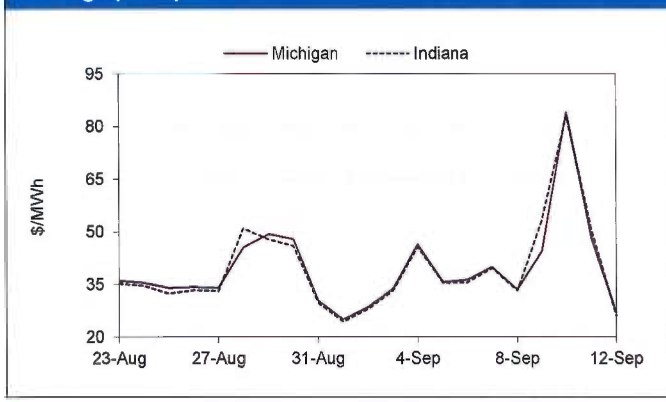


Nuclear availability data source: NRC

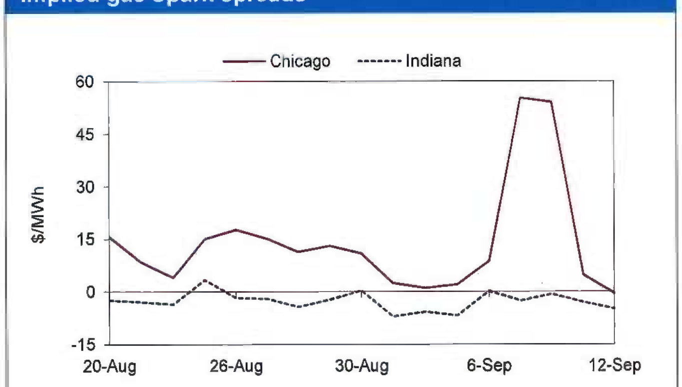
PJM AD vs Indiana coal heat rates



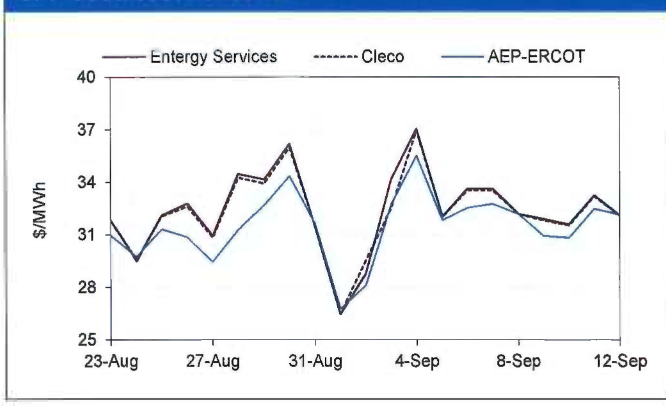
Average peak price



Implied gas spark spreads



SPP Southeast nodes LIP



Midwest Prices at a Glance $/MWh

Day-ahead markets for 13-Sep-13

Indiana

Day-ahead Peak	31.00
Day-ahead Off-Peak	20.50
Prompt Peak	34.63
Prompt Off-Peak	26.85

PJM AD

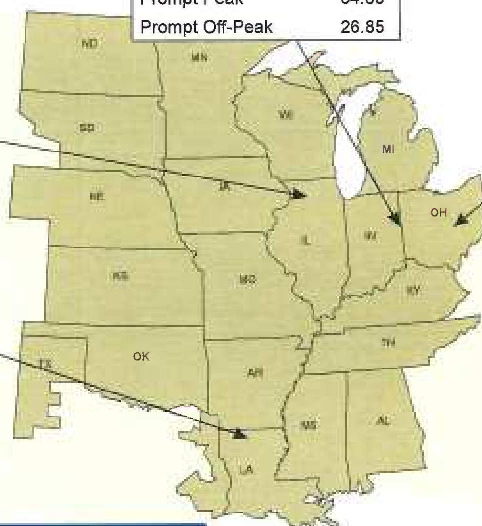
Day-ahead Peak	30.75
Day-ahead Off-Peak	22.00
Prompt Peak	37.90
Prompt Off-Peak	29.50

Northern Ill

Day-ahead Peak	32.75
Day-ahead Off-Peak	19.00

Entergy

Day-ahead Peak	32.50
Day-ahead Off-Peak	21.50



Day-ahead minus hourly spread

12-Sep-13	Peak	Off-Peak
MISO		
Indiana	12.20	2.66
Michigan	12.56	3.50
Minnesota	22.15	5.48
Illinois	9.28	-2.93
PJM		
Duke	8.64	-1.14
Northern Ill	7.15	-2.74
A-D	5.89	-1.33

SPP imbalance prices: Flow date — 12-Sep-13

	Peak	Off-peak
SPP North		
Cooper	31.52	20.62
Gentleman	31.53	18.14
Holcomb	31.93	23.75
Jeffrey	31.54	18.44
Emporia	31.42	21.80
Empire	32.55	22.03
Wolf Creek	32.65	22.13
WAPA-Nebraska	31.53	18.21
SPP East		
Sibley	33.51	21.95
Ameren Missouri	32.38	21.59
AECI	32.37	21.70
SPA-Arkansas	32.23	21.67
SPP South		
Sooner	32.71	22.17
Muskogee	30.53	21.51
Oneta	32.35	22.15
Redbud	28.58	22.14
Seminole	32.84	22.08
Kiamichi	32.85	22.08
Wilkes	32.13	21.79
Arsenal Hill	32.10	21.79
Entergy	32.10	21.64
Cleco	32.10	21.66
Ercot-East	32.14	21.81
Ercot-North	32.66	22.55
SPP West		
Tolk	32.92	23.43
WAPA-Colorado	31.68	20.17
Blackwater	32.96	23.48
EDDY	32.90	23.40

Emissions-adjusted dark spreads

	SO_2		24-hour
	Peak	Off-peak	average
Indiana	10.61	0.11	7.11
Entergy	6.48	-4.52	2.81
Northern Ill	12.13	-1.62	7.55
PJM A-D	6.06	-2.69	3.14

Hourly price averages

	Peak		Off-peak	
	12-Sep-13	11-Sep-13	12-Sep-13	11-Sep-13
MISO				
Indiana	26.05	50.65	22.84	26.59
Michigan	26.82	48.31	23.34	27.48
Minnesota	25.14	45.55	20.90	26.02
Illinois	25.24	40.95	23.17	25.38
PJM				
Northern Ill	27.35	49.74	26.99	29.65
A-D	28.86	59.60	27.83	30.18
Duke	27.43	72.68	27.13	29.25

Day-ahead peak spreads

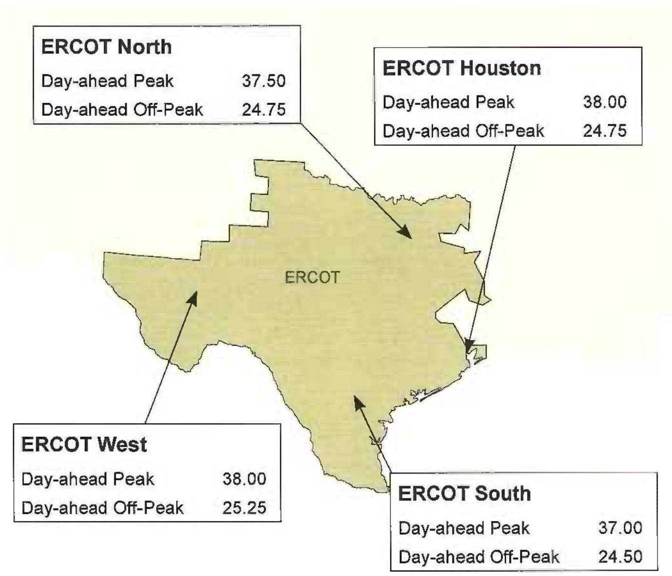
	Indiana	Northern Ill	PJM A-D	PJM West	Entergy	Southern
Indiana	—	-1.75	0.25	-7.00	-1.50	-3.76
Northern Ill	1.75	—	2.00	-5.25	0.25	-2.01
PJM A-D	-0.25	-2.00	—	-7.25	-1.75	-4.01
PJM West	7.00	5.25	7.25	—	5.50	3.24
Entergy	1.50	-0.25	1.75	-5.50	—	-2.26
Southern	3.76	2.01	4.01	-3.24	2.26	—

Sources: ISOs, Argus assessments

argus

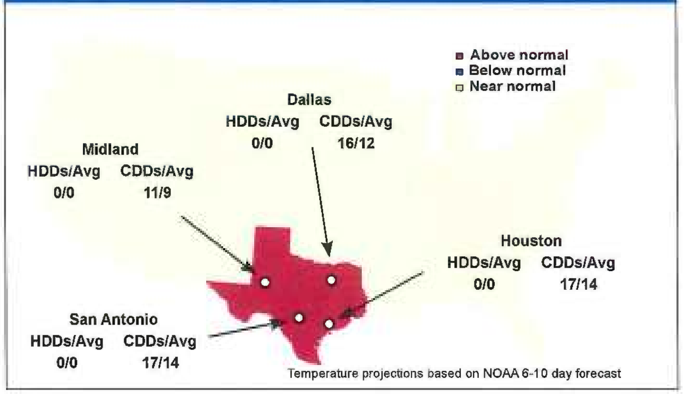
ERCOT Prices at a Glance $/MWh

Day-ahead markets for 13-Sep-13



Houston Ship Channel daily natural gas index *(all Houston Ship Channel transactions)*	**$3.610/mmBtu**

Degree days outlook vs temperature: 19-Sep



Day-ahead minus real time

12-Sep	Peak ($/MWh)	Off-peak ($/MWh)
Hubs		
Houston	7.23	0.58
North	4.67	0.05
South	6.58	0.50
West	11.62	0.24
Load zones		
Houston	7.47	0.58
North	4.35	-0.07
South	7.00	0.51
West	-36.97	0.54

ERCOT PRB coal dark spreads

(Emissions-adjusted)	Peak	Off-peak	24-hour
Houston	12.56	-0.69	8.14
South	11.56	-0.94	7.39
North	12.06	-0.69	7.81
West	12.56	-0.19	8.31

Note: Dark spreads are derived first by determining the value for a representative mix of coals and their transportation to the power hub. After adjusting for the amount of sulfur output from that proportionate coal mix in the production of a megawatt hour, the value of SO_2 allowances under current regulations is added to the cost of generation (heat rate 10 mmBtu/MWh x mmBtu value of the coal). This cost of generation is subtracted from the day's power hub clearing price, which is either the *Argus* index or assessment.

Day-ahead nodal prices

14-Sep	Peak ($/MWh)	Off-peak ($/MWh)
Hubs		
Houston	37.78	25.35
North	37.36	25.35
South	37.62	25.35
West	38.19	25.39
Load zones		
Houston	37.93	25.35
North	37.43	25.35
South	37.95	25.35
West	49.33	25.63
Hub average	**37.73**	**25.36**
Bus average	**37.56**	**25.36**

Market-implied heat rates and spark spreads

		Heat rate	Spark spreads in 000 Btu/kWh at heating efficiencies of:					
		(Btu/kWh)	7	8	10	12	15	18
Peak	Houston	10,526	12.73	9.12	1.90	-5.32	-16.15	-26.98
	North	10,417	12.30	8.70	1.50	-5.70	-16.50	-27.30
	South	10,511	12.36	8.84	1.80	-5.24	-15.80	-26.36
	West	10,795	13.36	9.84	2.80	-4.24	-14.80	-25.36
Off-peak	Houston	6,856	-0.52	-4.13	-11.35	-18.57	-29.40	-40.23
	North	6,875	-0.45	-4.05	-11.25	-18.45	-29.25	-40.05
	South	6,960	-0.14	-3.66	-10.70	-17.74	-28.30	-38.86
	West	7,173	0.61	-2.91	-9.95	-16.99	-27.55	-38.11

West Markets

Continued from page 1

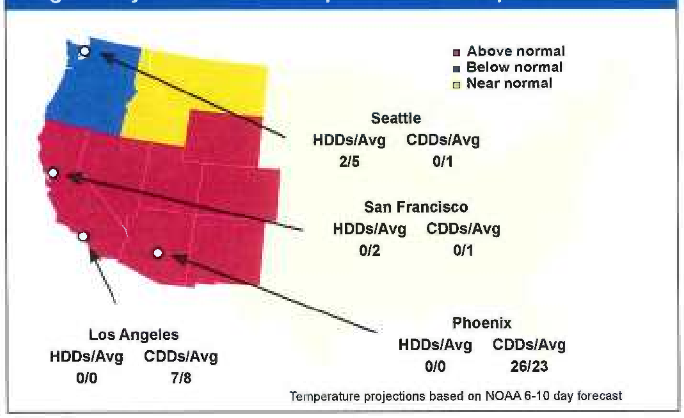
- Supply trapped in the Pacific northwest prompted further declines at Mid-C today for 16 September flows. "Assuming an all-in heat rate of 9.0 as a floor for the gas fleet, **the Mid-C floor is somewhere around $32/MWh,"** Jeff Richter, principal at EnergyGPS told *Argus*.

- Implied heavy load heat rates have crashed this week from 19.35mmBtu/MWh to a "measly" 11.21 for today. "Since that is still clearly in the gas stack, hydro continues to generate more megawatts and **eastside flows are finding a home in the Pacific northwest,"** he said.

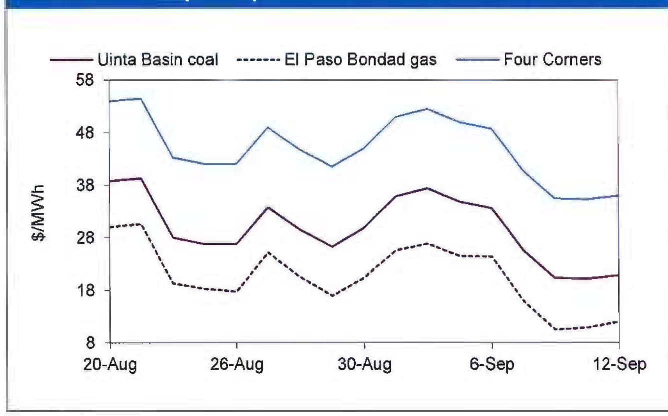
- **Inland west day-ahead prices fell sharply this week,** following a downtrend in the broader region. Mead peak averaged $40.91/MWh for the 9-14 September delivery period, down 18pc from the previous week. Palo Verde fell 17pc to $36.22. Four Corners slid 21pc to $39.27.

- **Past and future rainfall might account for the decline in prices for Mid-Columbia October peak** since the start of September. The contract was yesterday assessed by *Argus* at $35.80, down 6pc since it assumed the prompt-month position. Portland has had nearly three times the normal amount of rainfall for the period.

Degree days outlook vs temperature: 19-Sep



Four Corners spark spreads



Forward markets $/MWh

	Mid-Columbia				Palo Verde				SP-15				NP-15			Mead		
	Peak			Off-Peak	Peak			Off-Peak	Peak			Off-Peak	Peak		Off-Peak	Peak		Off-Peak
	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price
Oct-13	34.50	9.32	13.95	28.43	36.25	11.35	11.76	27.00	46.50	20.36	31.67	36.90	43.00	14.83	36.38	39.35	14.45	28.75
Nov-13	37.25	11.05	16.54	31.18	34.00	8.78	9.31	27.60	45.78	19.17	30.75	36.88	43.18	14.56	36.25	38.50	13.28	30.30
Dec-13	41.43	13.99	19.98	34.38	35.75	9.28	10.95	27.55	45.85	17.92	25.64	37.50	43.88	14.77	36.75	39.75	13.28	29.85
Jan-14	38.25	10.57	16.39	32.15	35.85	8.87	11.34	28.05	45.70	17.27	25.86	37.65	42.20	12.93	37.60	38.70	11.72	29.75
Feb-14	36.00	8.30	14.57	30.85	35.80	8.81	10.53	28.15	45.75	17.34	24.87	37.70	42.30	13.02	37.70	39.60	12.61	30.40
Mar-14	32.95	5.52	11.95	27.40	35.80	9.05	9.77	28.15	45.75	17.63	24.46	37.70	42.00	12.78	34.10	40.10	13.35	30.75
Q4-13	37.63	11.39	16.72	31.43	35.35	9.82	10.69	27.38	46.05	19.17	29.36	37.13	43.30	14.68	36.48	39.20	13.67	29.65
Q1-14	35.75	8.15	14.32	30.10	35.80	8.89	10.53	28.10	45.75	17.43	25.08	37.70	42.18	12.89	36.43	39.48	12.54	30.30
Q2-14	27.58	1.01	5.94	12.75	36.65	10.57	11.18	23.75	43.98	16.26	23.09	32.15	39.08	10.14	29.15	40.13	14.07	25.83
Q3-14	43.25	15.95	21.35	28.28	43.70	16.64	17.75	29.10	52.15	23.74	30.47	38.65	47.50	17.96	36.10	47.40	20.34	31.30
Q4-14	39.90	11.52	18.33	34.15	37.30	9.79	11.86	29.68	48.20	19.08	27.30	39.10	45.83	15.09	37.90	40.88	13.34	31.88
Q1-15	38.73	9.31	16.42	32.78	38.25	9.56	12.26	29.78	47.10	16.75	25.90	38.65	43.70	12.36	36.63	41.65	12.96	31.78
Q2-15	29.05	2.52	6.67	14.90	37.00	10.42	10.90	24.93	44.15	15.55	22.79	33.40	40.08	10.26	29.73	40.23	13.67	26.85
Q3-15	44.40	16.88	21.65	28.70	44.40	16.74	17.76	27.33	52.05	22.82	29.88	38.93	47.15	16.83	36.60	47.83	20.19	29.38
Cal-14	36.60	9.13	14.96	26.35	38.35	11.46	12.82	27.70	47.50	19.10	26.47	36.90	43.65	14.03	34.95	41.95	15.06	29.90
Cal-15	38.40	10.33	15.93	27.70	39.55	11.74	13.32	28.23	48.00	18.46	26.43	37.60	44.33	13.53	35.35	42.90	15.09	30.20
Cal-16	40.00	11.55	16.85	29.10	41.58	13.08	14.57	29.80	49.45	19.25	26.96	39.20	46.10	14.78	36.78	44.65	16.18	31.70
Cal-17	42.40	13.24	18.25	30.85	43.85	14.70	16.06	32.00	51.25	20.07	28.25	41.30	47.75	15.61	38.80	47.95	18.80	33.83

West Markets

Western generating unit outages

Capacity	Unit	Owner	Fuel	Begins	Reason
7,864	Total CAISO units curtailed	various	various	NA	planned and unplanned
820	Big Creek	SCE	hydro	28-Aug-13	@436MW Planned
337	Contra Costa 6	GenOn	gas	5-Jul-12	Planned, Unplanned
337	Contra Costa 7	GenOn	gas	4-Jun-12	Unplanned
250	Desert Sunlight 250	Nextera Energy	solar	11-Sep-13	Unplanned
300	Desert Sunlight 300	Nextera Energy	solar	16-Aug-13	Unplanned
335	El Segundo 3	NRG Energy	gas	26-Aug-13	Unplanned
933	Hyatt-Thermalito Pump-Gen	CDWR	hydro	2-May-12	@457MW Planned, Unplanned
612	Russell City	Calpine	gas	13-Sep-13	@357MW Planned
374	Gianelli Pump-Gen	CDWR	hydro	30-Aug-13	@80MW Planned, Unplanned

Spot natural gas in $/mmBtu

Location	Average	Low	High
PG&E Citygates	3.970	3.960	4.000
Stanfield	3.360	3.330	3.450
SoCal Gas Co	3.630	3.610	3.750
El Paso San Juan Basin	3.475	3.455	3.490
El Paso Permian Basin	3.475	3.450	3.485
El Paso, South Mainline	3.750	3.740	3.750
Northwest Sumas	3.315	3.280	3.380
Northwest Wyoming	3.380	3.320	3.500

Forward natural gas in $/mmBtu

Location	October	Nov 2013-Mar 2014	Apr 2014-Oct 2014
El Paso Permian	3.557	3.643	3.808
El Paso San Juan	3.549	3.653	3.777
Northwest, Wyoming	3.504	3.671	3.720
Northwest PL at Sumas	3.442	4.039	3.782
PG&E Citygates	4.025	4.016	4.197
SoCal Gas	3.735	3.845	4.017

Gas-implied, carbon-adjusted spark spreads

	NP-15		SP-15	
Marginal unit	Heat rate (mmBtu/ MWh)	Carbon cost ($/MWh)	Heat rate (mmBtu/ MWh)	Carbon cost ($/MWh)
Gas-implied	11.335	7.232	13.438	8.57
Carbon-adjusted	9.766	6.230	11.429	7.29
Western grid electric exports				5.14
Bonneville Power Administration exports				0.30
Powerex electric exports				0.35
Adjusted spark spreads in $/MWh				
Heat rate	7	8	10	12
NP-15				
Gas-implied	17.21	13.24	5.30	-2.64
Carbon-adjusted	12.74	8.14	-1.08	-10.30
Carbon cost	4.47	5.10	6.38	7.66
SP-15				
Gas-implied	23.37	19.74	12.48	5.22
Carbon-adjusted	18.90	14.64	6.10	-2.44
Carbon cost	4.47	5.10	6.38	7.66

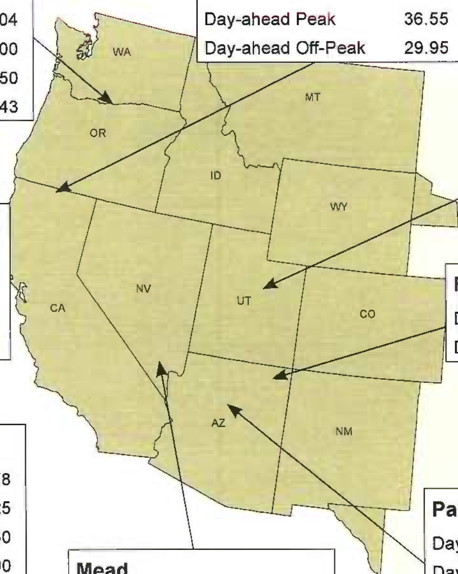
The data display the spread of fuel and carbon costs of running a power plant compared with the power price at NP-15 and SP-15, along with the carbon cost per heat-rate and for unspecified power imports. Data for SP-15 uses the day-ahead power price at SP-15 and the day-ahead gas price at SoCal. Data for NP-15 uses the day-ahead power price at NP-15 and the day-ahead gas price at PG&E Citygates. Both use the assessed December 2013-Delivery CCA price for carbon costs. For more information about this data, please contact airdaily@argusmedia.com or +1 (202) 775-0240.

Market-implied heat rates and spark spreads

		Heat rate	Spark spreads in 000 Btu/kWh at heating efficiencies of:					
		(Btu/kWh)	7	8	10	12	15	18
Peak	COB	10,069	11.14	7.51	0.25	-7.01	-17.90	-28.79
	Four Corners	11,248	14.64	11.19	4.30	-2.59	-12.93	-23.26
	Mead	10,675	13.34	9.71	2.45	-4.81	-15.70	-26.59
	Mid-C	10,131	10.52	7.16	0.44	-6.28	-16.36	-26.44
	Mona	9,316	7.95	4.52	-2.35	-9.22	-19.53	-29.83
	NP 15	11,335	17.21	13.24	5.30	-2.64	-14.55	-26.46
	Palo Verde	10,223	11.70	8.07	0.81	-6.45	-17.34	-28.23
	SP 15	13,438	23.37	19.74	12.48	5.22	-5.67	-16.56
Off-peak	COB	8,251	4.54	0.91	-6.35	-13.61	-24.50	-35.39
	Four Corners	8,708	5.88	2.44	-4.45	-11.34	-21.68	-32.01
	Mead	8,540	5.59	1.96	-5.30	-12.56	-23.45	-34.34
	Mid-C	8,631	5.48	2.12	-4.60	-11.32	-21.40	-31.48
	Mona	7,278	0.95	-2.48	-9.35	-16.22	-26.53	-36.83
	NP 15	8,564	6.21	2.24	-5.70	-13.64	-25.55	-37.46
	Palo Verde	8,402	5.09	1.46	-5.80	-13.06	-23.95	-34.84
	SP 15	10,813	13.84	10.21	2.95	-4.31	-15.20	-26.09

West Prices at a Glance $/MWh

Day-ahead markets for 13-Sep-13



Mid-Columbia	
Day-ahead Peak	34.04
Day-ahead Off-Peak	29.00
Prompt Peak	34.50
Prompt Off-Peak	28.43

COB	
Day-ahead Peak	36.55
Day-ahead Off-Peak	29.95

Mona	
Day-ahead Peak	32.00
Day-ahead Off-Peak	25.00

NP-15	
Day-ahead Peak	45.00
Day-ahead Off-Peak	34.00
Prompt Peak	43.00
Prompt Off-Peak	36.38

Four Corners	
Day-ahead Peak	38.75
Day-ahead Off-Peak	30.00

SP-15	
Day-ahead Peak	48.78
Day-ahead Off-Peak	39.25
Prompt Peak	46.50
Prompt Off-Peak	36.90

Palo Verde	
Day-ahead Peak	37.11
Day-ahead Off-Peak	30.50
Prompt Peak	36.25
Prompt Off-Peak	27.00

Mead	
Day-ahead Peak	38.75
Day-ahead Off-Peak	31.00
Prompt Peak	39.35
Prompt Off-Peak	28.75

Day-ahead minus hourly spread

12-Sep-13	Peak	Off-Peak
CAISO		
COB	0.74	0.57
Four Corners	-6.74	-2.21
Mead	-3.72	-0.11
Mona	-4.09	23.32
NOB	-0.14	4.44
NP-15	2.06	2.39
Palo Verde	-7.32	-1.30
SP-15	4.37	5.46

Source: CAISO

Hourly price averages

	Peak		Off-peak	
	12-Sep-13	11-Sep-13	12-Sep-13	11-Sep-13
CAISO				
COB	43.07	30.03	29.24	31.34
Four Corners	42.07	23.09	26.96	28.89
Mead	43.22	28.39	27.61	29.59
Mona	43.84	30.03	0.68	0.81
NOB	44.07	30.56	28.10	30.12
NP-15	43.94	30.75	31.36	33.36
Palo Verde	41.99	20.31	26.92	28.84
SP-15	43.38	30.92	28.04	30.07

Source: CAISO

Emissions-adjusted dark spreads

	SO_2		24-hour average
	Peak	Off-peak	
COB	10.53	3.93	8.33
Four Corners	23.58	14.83	20.66
Mead	12.73	4.98	10.15
Mona	16.83	9.83	14.50
Mid-C	8.02	2.98	6.34
NP-15	18.98	7.98	15.31
Palo Verde	21.94	15.33	19.74
SP-15	22.76	13.23	19.58

Day-ahead peak spreads

	COB	Four Corners	Mead	Mona	Mid-C	NP-15	Palo Verde	SP-15
COB	—	-2.20	-2.20	4.55	2.51	-8.45	-0.56	-12.23
Four Corners	2.20	—	0.00	6.75	4.71	-6.25	1.64	-10.03
Mead	2.20	0.00	—	6.75	4.71	-6.25	1.64	-10.03
Mona	-4.55	-6.75	-6.75	—	-2.04	-13.00	-5.11	-16.78
Mid-C	-2.51	-4.71	-4.71	2.04	—	-10.96	-3.07	-14.74
NP-15	8.45	6.25	6.25	13.00	10.96	—	7.89	-3.78
Palo Verde	0.56	-1.64	-1.64	5.11	3.07	-7.89	—	-11.67
SP-15	12.23	10.03	10.03	16.78	14.74	3.78	11.67	—

Source: Argus assessments

Impact of Renewables at a Glance

Northwest and California fundamentals: Changes are based on prior day

Real-time markets for 12-Sep-13

BC line loadings

	Average	Change
Peak (MW)	-400	-208
Off-peak (MW)	-99	-210
Capacity utilization (percent)	-18.6	-14.1

BPA area

	Average	Change
Wind output		
Peak (MW)	67	-124
Off-peak (MW)	278	85
Hydroelectric output		
Peak (MW)	8,027	-14
Off-peak (MW)	4,387	-236

COI line loadings

	Average	Change
Peak (MW)	2,080	560
Off-peak (MW)	1,329	222
Capacity utilization (percent)	38.1	6.7

PDCI line loadings

	Average	Change
Peak (MW)	1,027	341
Off-peak (MW)	620	116
Capacity utilization (percent)	29.8	8.9

COB

	Average	Change
Real-time peak ($/MWh)	43.07	13.05
Real-time off-peak ($/MWh)	29.24	-2.09

NOB

	Average	Change
Real-time peak ($/MWh)	44.07	13.51
Real-time off-peak ($/MWh)	28.10	-2.01

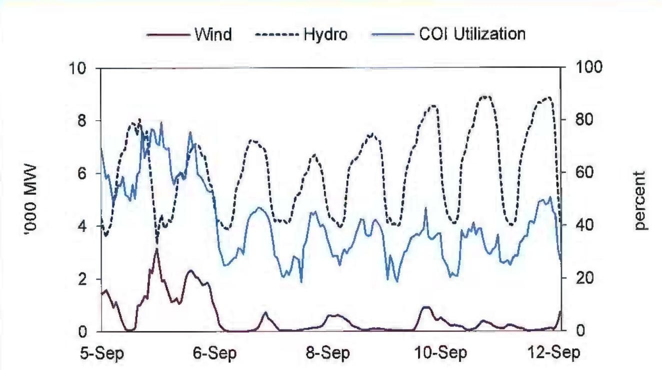
CAISO real-time ancillary services

	Average ($/MW)
Regulation down peak	1.05
Regulation down off-peak	0.24
Regulation up peak	0.63
Regulation up off-peak	0.39
Spinning reserve peak	0.01
Spinning reserve off-peak	0.01

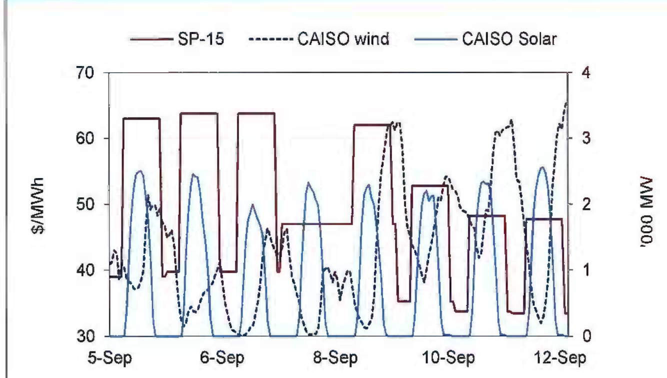
California

	Average	Change
Wind output		
Peak (MW)	1,385	-785
Off-peak (MW)	2,700	411
Hydroelectric output		
Peak (MW)	2,185	164
Off-peak (MW)	924	-31

BPA generation vs COI utilization



SP-15 vs CAISO generation



Markets

Central US heat buoys Nymex gas

US natural gas futures ended higher today as the market weighed forecasts for demand-boosting hot weather next week against the impending moderation in seasonal temperatures.

Nymex gas for October delivery rose by 3.9¢/mmBtu, or 1.1pc, to settle at $3.677/mmBtu. The 12-month strip and the 2014-calendar strip were each up by about 1pc to $3.902/mmBtu and $3.979/mmBtu, respectively. Prompt-month prices increased this week by 4pc after finishing higher in three of those five sessions.

Federal forecasters are predicting that above-normal temperatures will blanket the central US on 18-22 September and then spread to parts of the northeast, according to the National Weather Service. That warmer-than-normal weather should boost demand for gas-fired power above normal seasonal levels and limit gas inventory growth.

Prices received a boost yesterday after the US Energy Information Administration (EIA) reported that gas inventories grew by 65 Bcf (1.8bn m^3) in the week ended 6 September. The injection topped the five-year average increase for the week of 62 Bcf and the year-earlier injection of 27 Bcf. But it fell short of the consensus estimate in an *Argus* survey for a build of 67 Bcf.

Nymex natural gas settlements $/mmBtu

Contract	Price	Change	Volume*
Oct-13	3.677	0.039	87,177
Nov-13	3.755	0.043	44,355
Dec-13	3.902	0.045	15,926
Jan-14	3.989	0.046	18,686
Feb-14	3.991	0.047	4,760
Mar-14	3.952	0.047	7,411
Apr-14	3.872	0.043	9,056
May-14	3.890	0.044	617
Jun-14	3.918	0.044	248
Jul-14	3.948	0.044	208
Aug-14	3.965	0.043	60
Sep-14	3.965	0.043	97
Oct-14	3.988	0.043	1,323
Nov-14	4.060	0.044	337
Dec-14	4.214	0.044	600
Jan-15	4.297	0.045	899
Feb-15	4.270	0.045	14
Mar-15	4.207	0.043	363
Apr-15	3.998	0.032	99

*Volume data estimated by Nymex, subject to verification.

Argus North American Electricity Methodology

Prices are based on daily survey data received from the non-commercial departments of market participants. Day-ahead peak and off-peak volume-weighted price indexes and assessments are compiled based on this data. Argus publishes the total volume of trades reported, the number of transactions, the high price, low price, and the volume weighted average price where sufficient data exists.

In low-liquidity markets when insufficient data is received to support a volume weighted index calculation (less than three trades of 25MW minimum each are received) a clearly marked price assessment is made. Volume and number of trades are left blank when an assessment is made.

Peak and off-peak electricity price indexes are based on data submitted daily to Argus voluntarily by the risk-management divisions or non-commercial departments of market participants.

All data submitted is treated confidentially and used only to establish the index or form a market price assessment. The Argus electricity index procedures are audited at least annually by the company's global compliance officer.

Only firm deals equal to or greater than 25MW are included in each index. Firm delivery means that a contract for liquidated damages in the event of non-performance is in place. Swaps, contracts for difference, and derivative-linked deals are not included but financially settled deals are included where the price does not diverge from what is observed in the physical market.

In low-liquidity markets, Argus publishes assessments based on an intelligent range of trade. Argus assesses the range within which electricity did or could have traded, based on actual deals and bids and offers throughout the trading day for next-day power, historical price relationships and other market conditions.

Assessments are clearly identifiable from volume-weighted average indexes. The volume and number of trades will be blank where an assessment is made.

Argus **US Electricity** is published by Argus Media Inc.

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News

California power bill passes

California's legislature gave final approval to a bill that would reform the state's electric rate structure and promote more renewables in the state.

The Assembly approved AB 327 yesterday on a 71-1 vote, following Senate approval. The bill heads to California governor Jerry Brown (D) for his signature. Brown has been an outspoken proponent of the current renewable portfolio standard (RPS) and has spoken about trying to raise the program's target in the near future.

The bill undoes electric rate freezes put in during the aftermath of the California energy crisis a decade ago that have caused rising power costs to be paid by fewer customers of the state's investor-owned utilities (IOUs). The reform allows rising costs due to greater use of renewables to be spread out among all of the utilities' ratepayers, rather than just the largest customers.

The change will help the utilities balance their rate increases as they add large-scale renewable projects to meet the state's 33pc by 2020 RPS. AB 327 also requires them to allow for about another 5,500MW of net-metered rooftop solar and other behind-the-meter renewable projects through July 2017. The total amount of net metering available in each of the three major IOUs' service areas will be set at 5pc of their aggregate peak demand.

The bill also allows the California Public Utilities Commission (PUC) to require the IOUs to procure large-scale renewable electricity in excess of what they will need to meet the 33pc RPS. It is unclear under what circumstances the PUC would deploy that power, but California's utilities believe that the current RPS will be raised and they may seek to procure additional long-term renewable power contracts as soon as possible.

Several tax credits that lower the cost of renewable projects will expire in this decade and are not expected to be renewed.

Keep Colstrip, Avista says in plan

Utility Avista is expecting low power load growth for the rest of the decade and believes its share of the Colstrip coal-fired plant in Montana will be economical under any scenario.

The company filed its 20-year resource strategy with regulators in Washington and Idaho late last month, saying it has largely met its renewable energy portfolio requirements. The utility will need little new gas-fired generation soon because of reduced growth in retail load.

Loads were expected to grow 1.6pc annually in a plan submitted in 2011, but Avista's current strategy only expects 1pc/yr load growth in the next 20 years. Energy efficiency offsets projected load growth of 42pc over that period.

Avista owns 15pc, or 222MW, of units 3 and 4 at the Colstrip plant, which uses Powder River Basin coal. The Washington Utilities and Telecommunications Commission asked that the plant be studied for phase-out or more environmental controls.

If Colstrip was phased out by Avista by 2017, the utility would have to acquire generation from more than 300MW of gas turbines over the next seven years. This would add $52mn/yr to energy portfolio costs, 13pc higher than now expected. Greenhouse gas reductions would be about 1mn t/y over 16 years.

Selective catalytic reduction to reduce NO_x emissions from the two units would add $34mn/yr to power supply costs, while a carbon pricing scenario adds $25mn. Avista concluded that the plant should continue to operate as the company seeks to comply with regional haze regulation costs.

Additional generation resource needs are foreseen at less than 100MW for the rest of this decade, but grow to around 400MW over the 2020s. A request for proposals following the 2015 integrated resource plan will evaluate generation technologies and sites, but simple cycle combustion turbine gas units currently are preferred.

Weekend peak prices

Trade date for 13-Sep-13 for 14-Sep-13 to 15-Sep-13

	$/MWh	Price	Low	High	Volume (MW)	Trades
East	NY G	39.25	38.75	39.75	-	-
	PJM W	30.50	30.00	31.00	-	-
	NE Pool	51.50	51.00	52.00	-	-
ERCOT	Houston	37.75	37.25	38.25	-	-
	North	36.26	36.25	36.30	300	5
	South	37.50	37.00	38.00	-	-
	West	38.25	37.75	38.75	-	-
Midwest	Indiana	25.25	24.75	25.75	-	-
	N. Ill.	26.25	25.75	26.75	-	-
	PJM AD	28.25	27.75	28.75	-	-
Southeast	Entergy	23.25	22.75	23.75	-	-
	Southern	24.00	23.50	24.50	-	-

Weekend off-peak prices

Trade date for 13-Sep-13 for 14-Sep-13 to 15-Sep-13

	$/MWh	Price	Low	High	Volume (MW)	Trades
East	NY G	27.50	27.00	28.00	-	-
	PJM W	25.00	24.50	25.50	-	-
	NE Pool	28.25	27.75	28.75	-	-
ERCOT	Houston	25.25	24.75	25.75	-	-
	North	25.25	24.75	25.75	-	-
	South	25.25	24.75	25.75	-	-
	West	25.50	25.00	26.00	-	-
Midwest	Indiana	20.75	20.25	21.25	-	-
	N. Ill.	20.50	20.00	21.00	-	-
	PJM AD	24.00	23.50	24.50	-	-
Southeast	Entergy	18.00	17.50	18.50	-	-
	Southern	18.25	17.75	18.75	-	-

News

The utility has winter capacity needs from 2014 to 2016, at which time a 150MW capacity sale contract ends. The next winter capacity deficit begins in 2020. The company's first summer deficit, defined as a 14pc planning margin plus reserves, occurs in 2025.

Power supply costs increased 2.3pc annually over inflation for Avista from 2002 to 2012. That rate is expected to decline if forward price forecasts prove accurate and other cost reductions occur from sales of renewable energy credits (RECs), more energy efficiency and higher revenues from a capacity sale to Portland General Electric over the next two years.

The company investigated studies regarding changing water conditions from climate change, and found that higher water flows will occur earlier in the calendar year, indirectly benefitting customers during peak demand periods. A 30-year load forecast for Spokane, Washington, Avista's demand center, includes fewer heating degree days and more cooling degree days, but this will not have a large effect on retail loads.

Avista plans to meet its Washington state renewable energy requirements through hydroelectric plant upgrades, purchased power from Palouse Wind Project that began operation in December, the Kettle Falls biomass generator and selective REC purchases.

The company plans to obtain 77MW annual of energy efficiency gains over the next 10 years, which will reduce peak shaving needs by 104MW by 2023. Avista has identified 20MW of commercial demand response, and intends to study the market for the service over the next two years.

Most state commissions hold hearings on utility resource plans, give general guidance and allow other parties to intervene. Commissions do not approve the plans, but usually confirm that the utility has met its planning requirements.

Marilyn Brown rejoins TVA board

Marilyn Brown is returning to the Tennessee Valley Authority's (TVA) board of directors for a second term after members of the US Senate initially held up her nomination.

Brown's previous term ended last year and President Barack Obama nominated her for a second five-year term in March. Her confirmation process stalled because of opposition from some Republicans. The Senate eventually approved the nomination on 10 September, meaning Brown will rejoin the nine-member board and is available to attend its next meeting on 14 November in Mississippi.

Brown is a professor of energy policy in the Georgia Institute of Technology's School of Public Policy and a visiting scientist at Oak Ridge National Laboratory. Her current term expires on 18 May, 2017.

Separately, TVA today announced the appointment of 19 people to serve on its new Regional Energy Resource Council to advise it on current and future energy activities. The agency's board established the advisory panel in April to provide input on TVA's energy resources and to become a formal channel for regularly receiving diverse views on energy policy.

Dominion to move coal plant to gas

Dominion Virginia Power has received approval from the Virginia State Corporation Commission to convert the 227MW two-unit Bremo Power Station to natural gas.

The approval received on 10 September was the last regulatory hurdle Dominion had to clear. The company is obligated to complete the conversion by 1 July, 2014 or else it must ask the regulator for an extension.

Dominion had agreed to stop using coal and convert to gas as part of an air permit for the Virginia City Hybrid Energy Center, a 600MW coal-fired station that began commercial operations in July. The company previously said Bremo would stop burning coal in the autumn of 2013 if it receives permission for the $53.4mn conversion.

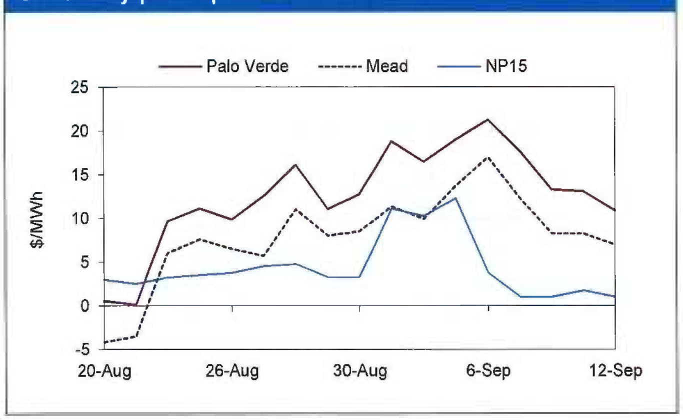
The low price and wide availability of natural gas as an alternative to coal and new environmental regulations that require costly expenditures to retrofit emission control equipment have made operating smaller, older coal-fired stations uneconomical, the company said.

Dominion plans to shut or convert all or part of five other coal-fired power stations and convert three small units to biomass. The Chesapeake Energy Center, which has four coal units generating a total of 595MW and eight gas turbines that can generate 122MW, is to close by 2015.

The same goes for the two coal-fired units of the three-unit Yorktown Power Station. The coal units produce a total of 323MW. The single-unit 74MW coal-fired North Branch Power Station in West Virginia will also close by 2015.

The three small Virginia stations being converted to biomass by 2014 are in Altavista, Hopewell and Southampton County.

SP15 daily peak spreads



News

Duke Carolinas to raise rates

The Public Service Commission of South Carolina gave Duke Energy Carolinas approval to increase rates by an average of 8.16pc for all customers.

The total annual rate increase will be implemented over two years. Electric rates will first rise by $80.4mn, an average of 5.53pc, beginning 18 September. Rates will increase by an additional $38.2mn, or 2.63pc, beginning 18 September, 2014. The total rate increase over the two-year period will be $118.6mn, an average of 8.16pc for all customers.

"We are pleased the commission has approved the settlement in this case," Clark Gillespy, Duke Energy's South Carolina state president, said. "We believe the settlement reflects a balance between the needs of our company and the needs of our customers."

The approved settlement was agreed upon by Duke Energy Carolinas, Wal-Mart, the South Carolina Energy Users Committee, Spartanburg Water, South Carolina Small Business Chamber of Commerce and the Office of Regulatory Staff.

The monthly bill for a typical residential customer using 1,000kWh a month in the first year would be $107.97, an increase of 7.5pc. In the second year it would be $110.76, a further 2.6pc rise. The average net rate increase for residential customers will be higher than for industrial customers.

"The approved settlement will allow us to keep the rate increase as low as we reasonably can, and still recover the investments we have made to modernize our system," Gillespy said.

The agreement stipulates that the company will not implement another base rate increase in South Carolina prior to September 2015.

Duke Energy Carolinas, a subsidiary of Duke Energy, provides about 20,000MW of owned electric capacity to 2.4mn customers in the western parts of North Carolina and South Carolina. This rate increase will affect about 540,000 customers in South Carolina.

Duke Energy Carolinas has a separate pending rate increase with the North Carolina Utilities Commission.

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Join us for informative sessions that will address the business and transactional aspects of the Cap-and-Trade program including the dynamics of procuring carbon allowances at auction and in the secondary market, offset procurement and strategies, managing regulatory and market changes, among many other relevant topics.

Why attend the carbon conference?

- Learn about innovative market products to help manage the risks of allowances and offsets
- Network with key carbon market participants including covered entities and intermediaries
- Understand how different entities look at program and hedge management
- Understand key developments to watch and expect as Cap-and-Trade enters its second compliance year
- Hear expert opinion on regulatory and market issues and challenges, and how these issues may impact market prices
- Participate in hands-on strategy implementation in auction theory and a "mock" auction
- Interact with major market participants through one-on-one breakout sessions

For more information, please contact:

Howard Walper | howard.walper@argusmedia.com | +1 713 360 7527

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Who attends?

- Compliance entities
- Offset providers
- Government officials
- Auction participants
- Traders, brokers
- Environmental NGOs

... and others

About the event organizers:

Argus, the publisher of *Argus Air Daily*, is a leading provider of data on prices and fundamentals, news, analysis, consultancy services and conferences for the global crude, oil products, natural gas, coal, electricity, emissions, bioenergy, fertilizer, petrochemical, metal and transportation industries. Please visit www.argusmedia.com for more information.

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DATES & VENUE

October 28 – 30, 2013
Hyatt Fisherman's Wharf, San Francisco, CA
www.argusmedia.com/california-carbon

REGISTRATION

Pre-registration (Register by August 23):	☐ $1095
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Standard registration (After September 20):	☐ $1495
Onsite registration (October 28-30):	☐ $1595

* Special group and government rates available. Contact Antonette Jones:
+1 713 429 6310 or antonette.jones@argusmedia.com

Fees include participation in all sessions, conference luncheon/reception, coffee breaks, continental breakfast and one set of conference documentation per person. Travel and accommodation costs are not included.

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Address: ______________________

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City/State or Province: ______________________

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Country: ______________________

Main Business/Activity: ______________________

DELEGATE 1 DETAILS

Name: Dr/Mr/Ms: ______________________

Job Title: ______________________

Telephone: ______________________

Email: ______________________

____

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TERMS AND CONDITIONS

• All registrations must be on the prescribed form, with payment enclosed. Payment will be accepted by credit card, bank wire or company check only.
• The conference organizers reserve the right to refuse the registration of any individual or company for any reason, at the conference organizer's sole discretion. The conference organizers reserve the right to impose conditions of entry for walk-in delegates, including refusal of entry.
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• Argus may disclose the delegate's contact information (full name, title, company name, company address, telephone and e-mail address) to other delegates, sponsors, speakers and/or conference partners.

Cancellation & Substitution
• Cancellations prior to September 28, 2013 will be eligible for a 50% refund. No refunds will be given after September 27, 2013.
• Substitutions from the same company are accepted at any time. Please contact us by October 25, 2013 with substitute name so we can have their materials ready.

Hotel Accommodation & Visa Application
Delegates are responsible for their hotel, travel and visa arrangements. Event room rates are available on a first-come, first-served basis.

Disclaimer
The organizers will not accept liability for non-approval of visas, individual transport delays and transport disruption. In such circumstances, our normal cancellation rules and penalties apply. Where matters beyond the reasonable control of the organizers impair or prevent the organizers from being able to perform their obligation under this event, the delegate releases the organizers from any liability, incidental or consequential, to such matters.

Attachment 29.1.2

Peter Greenwood, CA, ACA (ICAEW)

Partner, Accounting Advisory

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Vancouver, BC V7Y 1K3

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Fax 604-691-3031
Cell 604-671-5574
pgreenwood@kpmg.ca

Function and Specialization

Peter is a member of KPMG's advisory practice and specializes in accounting for complex transactions and accounting GAAP conversions.

Representative Clients

- BC Hydro
- Fortis Group
- PNG
- Yukon Energy Corporation
- Northwest Territories Hydro
- Columbia Power Corporation
- Alberta Motor Association

Professional Associations

- Chartered Accountant – BC CA and ICAEW in the UK

Languages

English

Background

Peter is a partner with KPMG's Accounting Advisory group. He specializes in complex accounting issue resolution, cost allocation and regulatory requirements.

Peter has 21 years of business experience, including 15 years in accounting advisory services and financial audit with KPMG (both in the UK and Canada) and 4 years at British Telecom in the UK at the Director/Principal level.

He has extensive experience advising major public and private sector clients, including issues on shared cost allocation, cost methodology and reporting to regulators. Examples of his experience are noted below. Peter is the Western Canada leader for KPMG's Accounting Advisory Services and includes the public sector in that practice.

Professional and Industry Experience

Development of major corporate cost study reporting projects, including reporting to regulatory bodies

- Peter has advised a number of Canadian public sector, listed and privately held entities, across a range of cost allocation and regulatory filing projects include;
- Western Canadian Gas Utility – leading two studies that reviewed the allocation of shared costs to different reporting entities and also the impact of costs related to capital activities that were not charged directly to products. The team documented their approach, findings and recommendations in a final report that was presented to the client and subsequently used by the client in their regulatory rate application.
- Western Canadian Electric Utility – led a team that reviewed the impact of costs related to capital activities that were not charged directly to products. Worked closed with the client to gather data from across the organizations, as well as gathering information on the external regulatory compliance requirements and precedents set within other jurisdictions. KPMG then completed a market research exercise to gather data on; leading practices, alternative methods, lessons learned and comparative costing for the services being allocated.
- Western Canadian Gas Utility – led a study to review the allocation of shared costs to different geographic reporting business units. The report also reviewed the impact on costs of a stand-alone call centre within one of the geographic business units and the impact on overall costs should that call centre be constucted. The team documented their approach, findings and recommendations in a final report that was presented to the client and subsequently used by the client in their regulatory rate application.
- Western Canadian Gas Utility – led a study to impact of costs related to capital activities that were not charged directly to products. The team documented their approach, findings and recommendations in a final report that was presented to the client and subsequently used by the client in their regulatory rate application.
- Western Motor Association – Peter was the quality review partner on a KPMG financial assessment and fee model build for a Provincial Registry Agent Network. The financial assessment was based on information provided directly by Registry Agents, the Association of Registry Agents, Motor Association and Service providers. The financial assessment was based on a representative sample of Registry Agents that was

determined to be statistically sound to support the integrity of the financial assessment and fee model.

- Prior to joining KPMG Canada in 2008, he worked at British Telecom Group ('BT') in the UK, a publicly listed Telecom utility. BT is a $40 Billion revenue organization with a staff of over 100,000.
- Director of Product Costing at BT 2007
  - Promoted internally to head team of 40 people that allocates and apportions all BT P&L and balance sheet (£15 Billion net assets) to services and products.
  - Provided essential financial projections for use in negotiations on future pricing with the UK Regulator, Ofcom. Managed team that models future costing predictions for next generation networks. Directed geographic analysis of BT's costs for broadband products
- Director of Regulatory Finance at BT from 2005 -2007
  - Peter held responsibility for annual regulatory reporting obligations for BT Group plc, managing team of ~10 and coordinating and communicating both externally and across the company.
  - He led BT in negotiations with Ofcom regarding all aspects of public reporting of products where BT has significant market power.

Accounting Advisory Services

- Leads the accounting conversions and management of accounting standard reporting at a number of commercial organizations as well as Provincial and Federal Crown Corporations over the last three years. The work addresses general and client-specific accounting issues and conversions to new accounting framework.
- Has led, developed and delivered training courses on accounting standards, including some specifically designed for the Office of the Auditor General ('OAG'), both for the Provincial OAG and also Federal OAG.
- Peter assists the Global Chair of KPMG's Public Sector Accounting Network across a number of International Public Sector Accounting Standards ('IPSAS') issues. As an example, he led KPMG's Global response to the 2013 Exposure Draft on the IPSAS Conceptual Framework.

Development of major corporate reporting framework and change management

- Manager for the BT conversion from UK GAAP to IFRS through 2004-2005
  - Led the significant transition of BT accounting, reporting and preparation for external audit from UK GAAP to reporting under IFRS for BT Group plc's statutory accounts.
  - Applied technical accounting knowledge of IFRS to accounting across all BT global and UK divisions.

Statutory audit

- Prior to joining BT in 2004 Peter worked as a senior manager within the KPMG UK and Bahamas audit practice.

Other Activities

- Peter is Treasurer for the West Vancouver Arts Centre Trust (the Kay Meek Centre).

Attachment 33.1.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 34.1

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name **Customer service (Gas and electric) – See attached**
Division ☒**Gas** **Cost Centre Number** **See Attached list**
☒**Electric** **Cost Centre Number** **See Attached list**

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

See attachment

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

See attachment

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

2013 is attached. No expected material variances for 2014 and 2015 as compared to 2013.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

Management review and input to various projects and initiatives as required.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

Yes, only by the amount charged to capital budgets.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Notes: This number is too small to break out in this fashion.			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

Very minimal, less than .25%

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

Minimal not directly charged – the main driver would be the number of customers.

9. Please indicate why these overhead capital activities are not charged directly to capital.

Doesn’t fit the definition of capitalize overhead.

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name **Distribution Engineering**

Division	☐**Gas**	**Cost Centre Number**	
	☒**Electric**	**Cost Centre Number**	**10586**

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

Responsible for distribution planning for the Kootenay and Okanagan regions. Develops future capital projects for distribution growth and sustainment capital. Maintains feeder load forecast for the Kootenays and Okanagan.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

97%

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

97%

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

75%

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

25% would still need to exist.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour	97	3	
Non-Labour	n/a	n/a	n/a
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

75%

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

See #7

9. Please indicate why these overhead capital activities are not charged directly to capital.

See #7

FortisBC
Capitalized Overhead Questionnaire

Cost Centre Name <u>Environment, Health & Safety</u>

Division	☒**Gas**	**Cost Centre Number**	______________
	☒**Electric**	**Cost Centre Number**	______________

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

> Operational support and guidance per Provincial and Federal regulatory requirements in the following areas: Occupational Health and Safety; Emergency and Business Continuity Planning; Environmental Management: Operational Compliance/Audit; Public Safety Management

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

> Very rarely do we charge directly to capital for gas or electric division works conducted by management.
> On the Electric side the Safety Coordinators do charge to capital when they are directly involved in a project. This percentage varies by Operational Group (T,D or G) but over the past three years, the percentages of SAWCO have been 39% (2010), 22% (2011), 12% (2012) and estimated to be 28% in 2013.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

> The same as in response to number 2 above and relatively stable.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

> The department works alongside Operations and the PMO teams, generally advising the Project Managers on Environmental and Safe Work Practices but unless the project is large enough they don’t charged directly to capital. The department is also involved in emergency response.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

No change. The department is staffed to meet ongoing Operational compliance.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour	25%	65%	10%
Non-Labour	Same	Same	Same
Electric	Capital	Operating and Maintenance	Administration
Labour	25%	65%	10%
Non-Labour	Same	Same	Same
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

The percentage would be the same as in number 6 above and is not expected to change.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

The ratio of small to large projects and the ratio of capital to O&M.

9. Please indicate why these overhead capital activities are not charged directly to capital.

There is no clear line of sight to the many small projects and that would make direct charging burdensome.

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name Engineering

Division	☐**Gas**	**Cost Centre Number**	
	☒**Electric**	**Cost Centre Number**	**10120**

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

   Takes the scope developed by System Planning and that were then approved and provide detail design and specifications.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

   76%

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

   82%

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

   Operational support.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

25% to 33% would still need to exist.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour	82	18	
Non-Labour		100	
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

15% to 20% related to System Planning and Standards

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

See #7

9. Please indicate why these overhead capital activities are not charged directly to capital.

See #7

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name **External Relations**

Division	☒**Gas**	**Cost Centre Number**	**2097 FEI / 6014 FEVI**
	☒**Electric**	**Cost Centre Number**	**10144**

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

> Relations with governments, aboriginal communities and other external stakeholders and community leaders.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

> We would charge directly to a capital project where our group is assigned to conduct community engagement around the project.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

> The expectation is given the current structure, a combined charge of less than $100 k per year to capital.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

> Where we do community engagement during the pre-CPCN phase of a project for large project or for smaller projects such as ROW clearing, maintenance capital, main and services, emergency response we wouldn’t charge to the project directly.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

Perhaps one FTE out of 13 FTE's in total would not be required.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour	50	50	
Non-Labour	50	50	
Electric	Capital	Operating and Maintenance	Administration
Labour	10	90	
Non-Labour	10	90	
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

Not anticipating any change.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

Management estimates

9. Please indicate why these overhead capital activities are not charged directly to capital.

Typically either small amount of time involved, preliminary discussion or part of a general initiative that includes both O&M and Capital making differentiation difficult. External Relations is tasked with building relationships with the communities we serve so in the course of that work we cover both capital and O&M.

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name______Facilities______________________________________

Division ☒**Gas** **Cost Centre Number** ____________________
☒**Electric** **Cost Centre Number** ____________________

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

> The Facilities department is responsible for operating and maintaining all FortisBC facilities. The services range from building asset operation and maintenance, physical security, space planning, office furniture and equipment and mailroom services. The department ensures FortisBC employees have a suitable work environment with safe and efficient buildings and workspaces.
>
> Facilities include:
> - 70 sites (58 gas and 12 electric) with buildings ranging from less than 1 year to 100 years in age
> - Over 1 million square feet
> - Over 100 acres of land

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

> Yes. Gas employees charge time to larger projects such as the Vancouver Island Operations Centre or the Meter Reader Facilities. A portion of Electric employee's time will also be charged into capital. 2 Electric FTE's charge about 25% of their time and 2 other Electric FTE's charge about 10% of their time into capital for work on project design and specification as well as construction supervision and similar activities.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

> Gas 5% - Electric 18.75%
> Both Gas and Electric are essentially in a steady state with slight increases possible in the 2015 – 2016 time frame.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

Many small projects will attract the same level of design, specification, construction supervision and the like.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

There would be no impact if capital work ceased to exist.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour	5%	90%	5%
Non-Labour	0.5%	99%	0.5%
Electric	Capital	Operating and Maintenance	Administration
Labour	5%	90%	5%
Non-Labour	0.5%	99%	0.5%
Notes: Capital projects are not charged for their space allotment within the buildings.			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

Estimate 5% of labour spent on overhead capital activities not directly charged to capital. This is a result of capital projects allotted space and working within buildings that are managed by Facilities staff.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

The primary driver is headcount (both employee's and contracted labour where FBC is providing accommodation or other services).

9. Please indicate why these overhead capital activities are not charged directly to capital.

There are a fair number of capital projects being supported and it would be administratively challenging to direct charge.

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name ______ Finance ______________________________________

Division ☐**Gas** **Cost Centre Number** ________________________
☒**Electric** **Cost Centre Number** ________________________

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

Budgeting and Forecasting, Corporate Reporting, Accounting, Accounts Payable and Miscellaneous AR.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

One AP Clerk 100% to Capital.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

Same

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

Supporting Regulatory and Operations in development of and reporting on capital expenditures. From capital plan, CPCNs to Management Reporting, project accounting and asset accounting.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

Yes

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour	20%	75%	5%
Non-Labour	5%	90%	5%
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

Budgeting & Forecasting 20 % Labour and 5% Non-Labour. Corporate Reporting 20% Labour and 5% Non-Labour Stable

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

Managements estimates.

9. Please indicate why these overhead capital activities are not charged directly to capital.

No direct line of sight and administratively burdensome.

FortisBC
Capitalized Overhead Questionnaire

Cost Centre Name **Human Resources**

Division	☒**Gas**	**Cost Centre Number**	**2071, 2172, 2171, 2173, 2174, 2320, 2290**
	☒**Electric**	**Cost Centre Number**	**10002, 10003, 10004, 10006, 10007, 10009**

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

> The overall goal of the Human Resources function is to ensure that the Company's workforce, now and into the future, has the level of skill and capacity to achieve the Company's business goals and objectives. Workforce planning, hiring practices, labour relations strategies, employee development, total compensation programs, and the associated processes and systems that support them must be effective, efficient and aligned to support the Company's business plans.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

> If there are systems upgrades (to the Payroll system for example) HR may charge a portion of time to capital. About 25% of one FTE. Other support would be from IT.
> HR time was also charged to the CEC project over one year that amounted to about 2.5 FTE's.
> Training will occasionally do some work that charges to capital projects (e.g. we have some training requirements for contractors and we provide the training for them). Estimate of this is that it is at most 7 – 10% of an FTE.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

> As per the response to number 2 above, do not expect the amount to be material.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

> This would include, payroll, compensation, benefits, etc. that would be in support of capital.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

Under the assumption that the company cease to undertake all capital project and simply maintain current systems, ie reduce the active employees by 50%: • Payroll (Gas) – reduce the FTE by 2 from a total of the current 8. An M&E, IBEW and COPE payroll will still be run regardless of the amount of employees in each affiliation • Payroll (Electric) – reduce the FTE by 1 from a total of the current 3. An M&E, IBEW and COPE payroll will still be run regardless of the amount of employees in each affiliation. • Advisory – reduce the FTE by 4 from a total of the current 9. Disability and labour relations would be unaffected as they are functions not driven by headcount by rather by policy and collective agreements • Pension & Benefits – reduce the FTE by 1.5 from a total of the current 8.5. M&E, IBEW and COPE benefits and pension plans will still be administered regardless of the amount of employees in each affiliation. • Learning & Development – reduce the FTE by 1.5 from a total of the current 20. 0.5 from training programs (fewer people to schedule and keep records for) and 1 from instructional design (no real reduction in the amount of content that needs to be built, but there would be a reduction in the amount of facilitation that needs to be done). No reduction to leadership development.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour	19.8%=(2+4+1.5+1.5)/(8+9+8.5+20)	15 FTE	Remaining FTE
Non-Labour	5%		
Electric	Capital	Operating and Maintenance	Administration
Labour	19.8%=(1+4+1.5+1.5)/(3+9+8.5+20)	1 FTE	Remaining FTE
Non-Labour	5%		
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

Based in #5, the FTE attributed to overheard capital would be estimated at 10 FTE for each year, 2013, 2014, 2015.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

Headcount and number of programs/plans/collective agreements was used as the main driver to estimate the percentage of labour forecast to be spent on overheard capital. The correlation to capital activity and HR is indirect.

9. Please indicate why these overhead capital activities are not charged directly to capital.

For the most part, HR hours are in support of the employees, not in direct support of the capital activities.

FortisBC
Capitalized Overhead Questionnaire

Cost Centre Name __**Information Systems**__

Division	☒**Gas**	**Cost Centre Number Gas**	__**2225, 2103, 2117, 2184, 2324, 2325**__
	☒**Electric**	**Cost Centre Number Electric**	__**10571, 10572, 10577**__

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

> 10571 & 2225 – exec admin for IS – PMO is captured in this cost centre
>
> 10572, 2184, 2324 & 2325 – applications – operating, sustainment & enhancements for all applications
>
> 10577, 2103 & 2117 – infrastructure – operating, sustainment & replacement for all infrastructure (hardware)

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

> On average they would charge approximately 40% directly to capital initiatives – sustainment, enhancements and replacement of technology and systems.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

> 40% on average on electric & 30% to 35% on gas

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

> - SAP for budgeting, planning & reporting
> - Microsoft Project for managing
> - GIS for planning and tracking assets
> - Several desktop server based applications
> - Servers and PCs used to support applications and provide the interface tool to project resources
> - Technical support for above systems and infrastructure – includes security, change control, yearly audits, etc.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

If all capital expenditures, both IT and other, including sustaining, were to be stopped there would be a reduction of approximately 50% in current staffing levels.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour	25%	60%	15%
Non-Labour	30%	65%	5%
Electric	Capital	Operating and Maintenance	Administration
Labour	30%	60%	10%
Non-Labour	35%	60%	5%
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

25% with no expected change based on existing long term plans for The Companies.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

The primary driver is the amount of capital activity based on budget. This amount as a ratio to O&M is the best indicator as to how much labour and non-labour is in support of capital outside of direct charge. The main driver that would affect indirect support is the capital budget. Expectations would be that a material change in overall capital spending, whether it be due to customer growth or asset management programs, would impact labour and non-labour costs. The affect would be on systems, licensing, support, infrastructure and labour required to support them.

9. Please indicate why these overhead capital activities are not charged directly to capital.

These activities are associated with programs that do not have an IT component where IT is a provider of a service that delivers tools and information to deliver the project. To try and allocate components of technology and the related support on an individual project basis would add costs for administration and is not practical.

FortisBC
Capitalized Overhead Questionnaire

Cost Centre Name **Internal Audit**

Division ☒**Gas** **Cost Centre Number** **1021**
☒**Electric** **Cost Centre Number** **10013**

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

> The Internal Audit department is responsible for planning and conducting reviews and audits of financial processes and capital projects. This department also conducts the Company's annual risk assessment process, administers the Ethics Point (Whistleblower) hotline, and monitors and evaluates the effectiveness and efficiency of the Company's internal controls. In recent years additional duties involving projects such as operational audits, Pandemic Response preparations, Enterprise Risk Management and Mandatory Reliability Standards have been taken on. Internal Audit's work is becoming increasingly more relied upon by the external auditors, saving them time and duplication in their own testing. This helped to keep the Company's external audit expense stable.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

> Approximately 5 percent of the Department costs are direct charges to capital for both Electric and Gas. Involvement of audit activities driving this allocation relate to inclusion of audit staff on planning committees for key capital projects, auditing of energy efficiency programs offered by both companies, information technology audits encompassing IT requirements of both companies, as well as specific post capital project completion audits. Lastly, we are also involved in the transition of both companies from HST back to the PST effective April 1, 2013.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

> Electric 5 percent for 2013, 2014 and 2015.
> Gas 5 percent for 2013, 2014 and 2015.
>
> Both companies are expected to remain consistent in terms of charges to capital.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

> Some of the Internal Auditors work with the business side by being involved on planning committees for major capital projects. In addition, some of the Internal Auditors work with the business side to assist in post implementation reviews of large capital projects. Finally, ongoing audits of areas such

as information technology and energy efficiency encompass key programs impacting capital. As such, one could argue that a portion of their time should recovered via the Capitalized Overhead charge for the involvement listed above.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

If the staffing levels were impacted as a result then yes, the cost centre(s) would operate with fewer staff. We estimate that the Electric budget would be reduced by one FTE and that the Gas budget would also see a one FTE reduction.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour	5%	85%	10%
Non-Labour	0%	70%	30%
Electric	Capital	Operating and Maintenance	Administration
Labour	5%	85%	10%
Non-Labour	2%	10%	88%
Notes: The allocations were based on the estimated effort required to support each type of activity. The capital estimate was based on the response to question 5 above.			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

For Gas approximately 5 percent of the labour cost forecast will be spent on overhead capital activities but not directly charged to capital. For Electric, approximately 5 percent of the labour cost forecast will be spent on overhead capital activities but not directly charged to capital.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc.). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

The primary driver would be the number of employees for both Gas and Electric. Additionally, if there are specific capital projects that Internal Audit is working on, there may be a direct charge to capital. (i.e. MRS).

9. Please indicate why these overhead capital activities are not charged directly to capital.

Generally, it is not practical to estimate the amount of capital activity an auditor might be involved in. In some circumstances, it would be possible to allocate cost directly to capital but again impractical.

FortisBC
Capitalized Overhead Questionnaire

Cost Centre Name_______Legal____________________________________

Division ☒**Gas** **Cost Centre Number** ______________________________

☒**Electric** **Cost Centre Number** ______________________________

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

> The Legal department services areas include Corporate (including joint ventures, mergers and acquisitions), Insurance, Litigation, Aboriginal, Tax, Securities, Trademarks, Contracts (including service contracts, gas supply contracts, leases and purchasing contracts), Environmental, Marketing, Employment and Labour, Intellectual Property and Real Property.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

> There is an expectation that direct charges to capital will be increasing in the near future due to the potential increase in the number of projects on the Gas side including asset maintenance projects, expansion projects and LNG projects.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

> If a project is small or does not have a deferral account that doesn’t necessarily mean that it does not attract some level of legal support. FBC would still have many smaller contracts that legal would be involved with.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

There could be a reduction of 1 – 2 FTE's out of a total staff complement of 8.5 FTE's (12 – 24%).

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour	12%		
Non-Labour	5%		
Electric	Capital	Operating and Maintenance	Administration
Labour	12%		
Non-Labour	5%		
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

There is an expectation that this will be increasing depending on how Operations breaks out their projects. i.e. if there are an increasing number of small projects they still are exposed to similar risk.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

The relative number of smaller versus larger prjects.

9. Please indicate why these overhead capital activities are not charged directly to capital.

It would be difficult to identify in some cases whether work was related to capital or O&M. It would be administratively challenging to direct charge.

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name______MRS___________________________________

Division	☐**Gas**	**Cost Centre Number**	____________________________
	☒**Electric**	**Cost Centre Number**	**10122**______________________

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

> FortisBC is responsible for ensuring that the Company becomes compliant, and maintains that compliance with the applicable BC Mandatory Reliability Standards. Ongoing effort is required to remain within auditable compliance with all standards and to evaluate the impacts and implement changes to existing and new standards.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

> Where a capital project requires it labour is direct charged into the project. Approximately 20% of one FTE or about 2-5%.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

> Should remain in that range.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

> About 50% of the Manager's time or about 5% of the labour budget is charged to planning and ultimately the Standing Orders.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

No impact.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour	5%	90%	5%
Non-Labour		100%	
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

Should remain in that range.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

No real driver. This would be a standing cost.

9. Please indicate why these overhead capital activities are not charged directly to capital.

Projects are not well enough defined to charge to.

FortisBC Capitalized Overhead Questionnaire

Cost Centre Name______PMO and Plant Operations__________________________

Division ☒**Gas** **Cost Centre Number** __________________________

☒**Electric** **Cost Centre Number** __________________________

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

> The Project Management Office is a strategic outcome based and flexible team that is focused on delivering business driven end products and providing support to:
>
> - Operations
> - Energy Solutions; and
> - External customers
>
> Plant Operations includes LNG Plant Operations and Gas Plant Compression Operations.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

> The PMO for the Gas side charges about 80% of their time directly to capital projects while Electric charges approximately 85% of the PMO time directly to capital.
> Gas LNG Plant Operations charges about 10% directly to capital while Gas Plant Compression Operations charges 20 – 35% to capital projects.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

> PMO should remain relatively stable for both Gas and Electric.
> Gas LNG Plant Operations may move from 10% to 20% in the 2015 – 2016 years, while Gas Plant Compression Operations charges may increase due to Business Development projects in the same time period.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

> Some Administrative/Support Staff and Supervision costs in the PMO are not directly charged to capital. For both Gas LNG and Compression departments there are virtually zero activities that are capital related.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

The PMO for both Gas and Electric would virtually disappear. LNG O&M would increase by about 10% and Compression O&M would increase by 20 – 35% per the response to number 2 above.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

No change. Any increase in capital project work would be managed by adding FTE’s and direct charge to capital.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

Capital intensity.

9. Please indicate why these overhead capital activities are not charged directly to capital.

Line of sight to the projects. It is more problematic and administratively burdensome to charge directly to many small projects.

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name **Property Services & Land**

Division	☒**Gas**	**Cost Centre Number**	**2046 & 6170**
	☒**Electric**	**Cost Centre Number**	**10015**

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

Costs related to managing all land rights and land tenure issues, including:

- property taxation forecasting and payment
- fee simple acquisitions and disposals of station lands
- leases of office space
- right of way agreements and Crown permits to support new customer connections
- coordinating environmental reviews related to property acquisitions and disposals
- First Nations negotiations
- Assess and generate third party crossing permits of high pressure pipelines
- sub-division review and approvals to ensure land rights are maintained as lands around facilities are developed by third parties
- public safety awareness communications in support of damage reduction initiatives
- encroachment removal and enforcement of land rights to maintain integrity of facilities and visibility of rights of way
- manage ongoing trespass, expropriation and legal files
- communication with right of way property owners and others affected by construction activities
- compiling line lists

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

About 70% of Electric. Maybe 10-15% on Gas side.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

See #2 above.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

Up to 40 – 50% on Gas could be attributable to indirect capital costs. Virtually zero on the Electric side.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

Would reduce by one FTE on Electric (out of two FTEs). Would reduce by 4 FTEs out of 10.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour	40 – 50 %	50%	5%
Non-Labour	5%	90%	5%
Electric	Capital	Operating and Maintenance	Administration
Labour	0%	95%	5%
Non-Labour	0%	95%	5%
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

In general a steady state.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

Level of capital intensity.

9. Please indicate why these overhead capital activities are not charged directly to capital.

No direct line of sight to the many sustaining capital jobs and it would be an administrative burden.

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name______Regulatory_____________________________________

Division ☐**Gas** **Cost Centre Number** ___________
☐**Electric** **Cost Centre Number** **10554___________**

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

The Regulatory Affairs department maintains the relationship with the BC Utilities Commission (BCUC) and ensures that the Company remains compliant with the regulations as set out in the Utilities Commission Act. As part of this compliance the regulatory affairs department co-ordinates the annual rate setting process (Revenue Requirements) and any related tariff rate Applications. It also co-ordinates applications for Certificates of Public Convenience and Necessity (CPCN's) for all capital expenditures. In addition to ensuring compliance and co-ordinating Applications, the regulatory department ensures that the company meets all of its reporting requirements with the BCUC.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

None of the cost center charges for electric Regulatory Affairs are charged directly to capital.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

Electric - 0%.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

As noted in question 1 above, the Regulatory Affairs department is heavily involved in CPCN type activities. These include Long-Term Capital Plans which communicate the long term direction of the Company's capital activities, Capital Expenditure Plans which seek approval of the Company's capital expenditures, Revenue Requirements which seeks to have the capital expenditures recovered through customer rates, individual CPCN Applications for individual capital projects that are not approved within a Capital Expenditure Plan and Capital Progress Reporting to the BCUC which communicate the progress, risks and opportunities being faced by individual capital projects.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

Yes. Approximately 2.5 of the 5 employees in Regulatory Affairs would no longer be required for electric.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour	50%	25%	25%
Non-Labour	30%	30%	40%
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

For Electric, approximately 50% of activities relate to capital, but are not directly charged to capital.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

The primary driver used to forecast the percentage related to, but not directly charged to capital is employee effort. The capital activities undertaken by Regulatory Affairs are separate and distinct from the non-capital activities, as they are separate regulatory processes.

9. Please indicate why these overhead capital activities are not charged directly to capital.

Sometimes these activities can clearly be attributable to an individual capital project, but sometimes they are related to many capital projects. In addition, the Company has historically communicated to the BCUC that the regulatory costs associated with capital projects are not directly charged to capital projects as these costs have been budgeted into Operating and Maintenance costs and are recovered in customer rates as such, except for any amounts that would be included in a capitalized overhead mechanism. This ensures that there can be no double count or double recovery of regulatory costs.

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name ______ Resource Planning ___________________________________

Division Gas Cost Centre Number ________________________
☒Electric Cost Centre Number 10088________________________

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

Power Supply directly manages the energy supply portfolio to ensure there is sufficient energy available at all times to meet load. This includes looking at requirements now and out to the extent of the Resource Plan 20 to 30 years in the future. We also provide resources to the Load Forecasting group to produce the overall electric load forecast. Finally, there are certain financial reporting requirements around the Company's load and power supply costs.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

There are no direct charges to capital at this time.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

Zero percent.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

We need to do a fair bit of IT work to upgrade our computer systems to operate under the renewed PPA and associated agreements that support WAX coming on-line. There is definitely a management component to this.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

Interesting question since in our case it implies the PPA is not renewed and hence the need to upgrade our systems to meet it goes away. This would actually most likely require more staff to manage as the Company would then have an immediate and very serious supply shortfall.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour	5%	90%	5%
Non-Labour			
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

The majority of the work is needed in 2013 and would be about 5%. Somewhat lower in 2014 and probably back to zero in 2015. If the Company brings forward requests to build new generating capacity, I'm not sure how we will relate to that. Not clear to me how the regulatory process fits into this as we would be heavily involved up to project approval stage at which point in time our direct job is "done" more or less expect for the associated contracts and agreements dealing with the new plant and power supply issues. BCH contracts for example, but I don't think that is really capital??

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc).. What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

Expect it to be a 0.25 fte for 2013 and 5 of us in the department, hence 5%.

9. Please indicate why these overhead capital activities are not charged directly to capital.

It may be possible and appropriate for us to do so. Power Supply hasn't really worked with capital projects much.

FortisBC
Capitalized Overhead Questionnaire

Cost Centre Name Supply Chain Management (Electric)

Division			
	☐**Gas**	**Cost Centre Number**	
	☒**Electric**	**Cost Centre Number**	**10503,10502,10588**

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

2190 – Management costs

2189 - warehouse and logistics, logistics of materials for capital projects

2188 – procurement, source and procure of capital materials

2037 – machine shop, weld shop, prefabrication shop, regulator shop. – fabrication and install for capital projects

2019 – radio network – FEI – Specify and install of capital radio equipment

6119 – radio network – FEVI - Same

2031 – Instrument Control Systems & Data Acquisition – SCADA instrumentation install, AMR equipment install

2030 – Meter Shop (meter recall)

2032 – Measurement Services (meter fleet management, equipment replacement)

2035 – 3rd party revenue (Measurement services (2030), radio network (2019), pulse handoff (ICS&DA)

10502 – Electric warehouse and logistics, logistics of materials for capital projects

10503 – Electric procurement, source and procure of capital materials

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

10502 - $1.577K (gross loaded labour) - Direct charge to capital $281K = 17.9%
10588 (material Load) Balance of 10502 is washed out through the Material load at year end = 100%
10503- $954K (gross loaded labour) – Direct charge to capital $457K = 47%

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

2013 – 10503 47%, 10588 100% of 10502, 10502 17.9% Should be relatively stable.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

By the nature of the business, virtually all Purchasing related work is capital in nature. Approximately 90% of inventory is charged to capital and the majority of the contract work is in support of capital equipment or services. To be conservative we estimate this to be about 75% of our effort.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

Warehousing would disappear. Purchasing would be reduced to 2 FTE.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour	75%	20%	5%
Non-Labour	50%	45%	5%
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

As above, about 75 percent. Forecast relatively stable.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

Management best estimates.

9. Please indicate why these overhead capital activities are not charged directly to capital.

Inventory is charged out to capital directly, but the support functions for inventory are not. Some contracts are not project specific but are capital in nature.

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name ______ Station Maintenance __________________________________

Division	☐**Gas**	**Cost Centre Number**	____________________________
	☒**Electric**	**Cost Centre Number**	**10224**______________________

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

> Is responsible for conducting any studies or justifications to determine what infrastructure might be needed to added to the Sub or Terminal Stations.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

> 55%

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

> The 2012 Direct Overhead budget indicated approximately 68 percent to be directly charged to capital. The ratio is not expected to change for 2014 or 2015.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

> See the Direct Overhead Order 11033802

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

None would remain.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour	95 percent	5 percent	
Non-Labour		100 percent	
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

40 percent. No changes anticipated.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

9. Please indicate why these overhead capital activities are not charged directly to capital.

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name ____ System Planning ____

Division	☐**Gas**	**Cost Centre Number**	____
	☒**Electric**	**Cost Centre Number**	**10218**

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

> Is responsible for conducting any studies or justifications to determine what infrastructure might be needed to added to the T&D system. Working through the regulatory process to have the project approved.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

> No, since by definition the project(s) do not technically exist.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

> The 2012 Direct Overhead budget indicated approximately 6 percent to be directly charged to capital. The ratio is not expected to change for 2014 or 2015.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

> See the Direct Overhead Order 11029688.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

Yes, 25 percent might remain.

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour	78 percent	22 percent	
Non-Labour		100 percent	
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

78 percent. No changes anticipated.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

Not able to charge to projects because the projects do not exist. Some time is attributable to providing operational support to System Control and Operations.

9. Please indicate why these overhead capital activities are not charged directly to capital.

Not able to charge to projects because the projects do not exist.

FortisBC
Capitalized Overhead
Questionnaire

Cost Centre Name______T&D B000264_______________

Division	☐**Gas**	**Cost Centre Number**	**_____________________________**
	☐**Electric**	**Cost Centre Number**	**B000264______________**

For the following questions please provide written overall answers for each cost centre:

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

   Network services; building and maintenance of transmission and distribution lines.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. Eg. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

   GLL 22.066 mil/ charged to cap 12.007 mil or 55%/ 1.7 mil charged indirect to stnd orders or 8% (14% of cap)

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

   No change, approx 47% to capital projects and approx 8% to indirect.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

   Health and safety(ie meetings, clothing, tools), fleet (ie relocating vehicles), warehousing (ie; satellite whse stocking and maintenance) , facilites (ie distribution of mail), Jrny upgr training for PLT's on capital crew, cell phones/ Land Lines/ satellite phones for employees on capital crews.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

Yes.. elimination of approx 105 FTE positions

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour	1.7mil	15.5mil	526k
Non-Labour	300k	442k	64k
Notes: Lab includes contracted manpower. Have to exclude T&D Sustaining Projects.			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

8%, no change...based on previous history.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

2012 actuals; direct hours charged by staff to Internal standing orders

9. Please indicate why these overhead capital activities are not charged directly to capital.

Most are not project specific (ie; small tools, safety equipment, training, communications for capital crews) or not practical to charge to multiple projects ie; locate contractors invoices.

Attachment 40.2

The Commission Panel directs the Company to recalculate its AFUDC rate based on the weighted average cost of debt from the Third Revised Application and the return on equity allowed through this Decision. The resulting approved AFUDC rate shall be applied to calculate the AFUDC amounts in 2005.

2.8.4 Capitalization of PowerSense Costs

FortisBC is proposing a change in the accounting treatment of certain PowerSense costs in the amount of $85,000, such that these costs are charged to capital rather than operations (Exhibit B-26, p. 4). The DSM Technical Committee discussed the reasons behind the request with only Mr. Wait expressing concern (Exhibit B-17, p. 3).

Mr. Wait argues that the $85,000 charge for DSM awareness should continue as an operating expense and not be capitalized. He expressed concern for capitalizing costs that do not have physical assets attached and the procedure would cost ratepayers more for ROE and equity (Wait Argument, p. 9). Currently the Company amortizes DSM (deferred energy management) costs over 8 years (Exhibit B-12, BCUC IR 34.1-34.3).

Commission Panel Determinations

The Commission Panel approves the change in accounting treatment of certain PowerSense costs as proposed by the Company. The Commission Panel directs that the upcoming depreciation and amortization study will address the appropriateness of the current amortization period for deferred DSM costs.

2.8.5 Deferred Charges

Net-of-tax Deferral Accounting

Currently, FortisBC treats DSM costs net-of-tax as directed in Commission Order No. G-55-95. All other deferred charges that have been recorded by the Company are on a gross of tax basis. At Transcript Volume 5, page 887, Commission Counsel questioned the appropriateness of recording all deferred charges on a net-of-tax basis. Mr. Meyers responded that, in his opinion, the net-of-tax treatment is appropriate to ensure proper matching of costs and benefits (FortisBC Argument, p. 59).

The Company proposes that deferred amounts related to the proposed 2005 O&M Expense and power purchase sharing mechanisms be recorded net-of-tax so that the associated income tax is correctly matched either to the customers or the shareholder (Exhibit B-12, Response to BCUC IR 34.5). The Company does not propose to extend net-of-tax treatment to other deferral accounts. The Company is of the position that any change in the

IN THE MATTER OF

FORTISBC INC.

2005 REVENUE REQUIREMENTS APPLICATION
2005-2024 SYSTEM DEVELOPMENT PLAN
2005 RESOURCE PLAN

DECISION

MAY 31, 2005

Before:

L.F. Kelsey, Commissioner and Panel Chair
P.G. Bradley, Commissioner

Attachment 41.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 42.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)