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September 9, 2011

Via Email
Original via mail

Ms. Alanna Gillis
Acting Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. (FortisBC) Application for 2012 -2013 Revenue Requirements and Review of 2012 Integrated System Plan Responses to Intervener Information Requests No. 1

Please find attached FortisBC's responses to Information Requests No. 1 from the British Columbia Old Age Pensioners' Association et al., British Columbia Sustainable Energy Association, Zellstoff Celgar Limited Partnership, and Mr. Alan Wait.

If further information is required, please contact the undersigned at (250) 717- 0890.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

1.0 Reference: FortisBC 2012 ISP – Volume 1 - ISP, pages 7, 8 and 10

1.1 Please confirm whether or not, in FortisBC's opinion, both the 50% in the BC Energy Plan and the 66% in the Clean Energy Act apply to just BC Hydro.

Response:

The 50 percent target proposed in the 2007 BC Energy Plan was directed toward BC Hydro, but FortisBC has voluntarily committed to the target.

The 66 percent target in the Clean Energy Act applies only to BC Hydro.

2.0 Reference: FortisBC 2012 ISP – Volume 1 - ISP, page 30 and Appendix K, Attachment 1

2.1 Please confirm whether or not the First Nations listed in Appendix K, Attachment 1 (page 12 of 138) were the ones provided a copy of the summary document.

Response:

The ISP summary document was provided to the Okanagan Nation Alliance, the Ktunaxa Nation and the Shuswap First Nation.

2.2 Did any First Nations follow-up on FortisBC's offer to "make presentations at (an) upcoming Council meeting"?

Response:

No.

2.3 What financial or other resources were offered to First Nations to facilitate their ability to attend open houses, to analyze and assess the summary document describing the ISP, and to provide written feedback?

Response:

FortisBC has offered capacity funding to the First Nations.

2.4 Will or have the First Nations been provided more detailed information regarding the ISP than the summary document?

Response:

Yes, full copies of ISP were delivered to the Okanagan Nation Alliance. The Ktunaxa Nation and Shuswap First Nation were offered the complete set of binders, but they felt they were not necessary and indicated they would contact FortisBC if they wanted specific sections of the document. No requests have been received to date.

2.5 On what date were First Nations provided the summary document describing the 2012 ISP requestin written feedback by September 30, 2012?

Response:

Summary documents were hand delivered to the Shuswap First Nation on June 23, 2011, to the Ktunaxa Nation on June 23, 2011 with a face to face meeting on July 6, 2011 and to the Okanagan Nation Alliance on June 28, 2011.

3.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 1

FortisBC 2012-2013 Revenue Requirements Application, Tab 6, page 17

3.1 Please provide a high level break down of FortisBC's annual capital spending since 2005 (Generation, Transmission, Distribution, and Telecom/SCADA/Protection & Control) as between a) spending for growth vs. b) spending to sustain/replace existing facilities.

Response:

Refer to BCOAPO IR1 Table A3.1 below for a breakdown of actual expenditures of Generation, Transmission, Distribution and Telecom/SCADA/Protection & Control categorized by growth and sustaining.

Table BCOAPO IR1 A3.1

	2005	2006	2007	2008	2009	2010
	Actual					
	($000s)					
Generation						
Growth	-	-	-	-	-	-
Sustaining	14,656	14,035	21,604	17,357	20,622	19,510
Subtotal	**14,656**	**14,035**	**21,604**	**17,357**	**20,622**	**19,510**
Transmission & Stations						
Growth	48,526	29,065	62,763	40,499	44,187	77,065
Sustaining	9,453	16,994	7,672	8,502	7,022	7,397
Subtotal	**57,979**	**46,059**	**70,435**	**49,001**	**51,209**	**84,462**
Distribution						
Growth	17,503	16,496	14,850	16,770	11,995	11,520
Sustaining	9,194	12,326	10,971	10,134	14,271	15,131
Subtotal	**26,697**	**28,822**	**25,821**	**26,904**	**26,266**	**26,651**
Telecommunications, SCADA, and Protection & Control						
Growth	-	36	162	1,111	1,801	1,512
Sustaining	708	1,130	1,030	1,807	768	684
Subtotal	**708**	**1,166**	**1,192**	**2,918**	**2,569**	**2,195**
Total	**100,040**	**90,082**	**119,052**	**96,180**	**100,666**	**132,818**

4.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 5

4.1 What is the expected completion date for the report that will outline the asset management implementation plan and provide the project cost estimate?

Response:

FortisBC's intention is to complete the report in time for its next Capital Expenditure Plan filing in 2013.

5.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 7

5.1 Please identify those projects in Section 2, 3, 4 or 5 that FortisBC considers to be Smart Grid developments.

<u>Response:</u>

Virtually all of the proposed projects in the Long Term Capital Plan support Smart Grid development to some degree, even if the Smart Grid is not a prime driver for the project. Following is a listing of projects which FortisBC considers to significantly support the development of the Smart Grid. Also noted are Smart Grid components which are addressed.

Generation:

- Corra Linn Unit 2 Life Extension – includes improvements in generator protection, metering, monitoring and communications.
- Lower Bonnington and Upper Bonnington Plant Totalizer Upgrade – includes improvements in generator metering and communications.
- Upper Bonnington, Lower Bonnington and Corra Linn Plants Automation – includes improvements in equipment monitoring and communications to support condition-based maintenance decisions.
- Electronic Equipment Replacement – includes improvements in generator protection, metering, monitoring and communications.
- All Plants Surveillance and Security – includes improvements in infrastructure security and communications.

Transmission and Stations:

- Ellison to Sexsmith Transmission Tie – includes improvements in communications through the addition of fibre-optic infrastructure.
- Grand Forks Transformer Addition – includes improvements in communications through the addition of fibre-optic infrastructure.
- Meshing Kelowna Loop – includes upgrades in protection and communications systems to improve customer reliability.
- DG Bell Static VAR Compensator – includes electronic control equipment which provides dynamic reactive support to support stable operation of the transmission system.
- Add Arc Flash Detection to Legacy Metal-Clad Switchgear – includes installation of light-detection protection technology to improve worker safety.

Telecommunications, SCADA and Protection and Control:

- Kelowna 138 kV Loop Fibre and Multiplexer Installation – includes improvements in communications through the addition of fibre-optic infrastructure.
- Kootenay Remedial Action Scheme - Install Redundant Backup System – includes improvements in protection systems to support maximal utilization of transmission infrastructure.
- Syncrophasor Data Collection Platform – includes improvements in monitoring and communications systems to support maximal utilization of transmission infrastructure.
- Okanagan Remedial Action Scheme - Install Redundant Backup System – includes improvements in protection systems to support maximal utilization of transmission infrastructure.
- Princeton to Oliver Fibre Installation – includes improvements in communications through the addition of fibre-optic infrastructure.
- Communication Upgrades – includes upgrades and replacement of communications equipment to support protection, monitoring and control of the transmission and distribution system.
- SCADA Systems Sustainment – includes improvements in SCADA control and communications to support monitoring and control of the transmission and distribution system.
- Backbone Transport Technology Migration – includes upgrades in communications through the adoption of new technology.
- Station Smart Device Upgrades – includes upgrades and replacement of substation protection and metering devices.
- Telecommunications Ring Closure – includes improvements in system operations by increasing communications system reliability.

General Plant:

- Advanced Metering Infrastructure – includes communications and metering upgrades to provide visibility of consumption and power quality information at customer premises. Also supports the addition of future upgrades such as distribution automation, voltage monitoring and control, and wide-scale integration of distributed generation or electric vehicles.
- Information Systems – includes upgrades and additions of technology to support the operation of the power system.

6.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 13

6.1 What is the level of cost accuracy attributed to each Class level in the AACE Classification?

Response:

FortisBC used the AACE Recommended Practice No. 18R-97 (February 2, 2005) – COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES (attached as BCOAPO IR1 Appendix 6.1). The following is a summary of the classes and accuracy range.

AACE Estimate Class	**Expected Accuracy Range** (Typical variation in low and high ranges)
Class 5	L: -20 to -50% H: +30 to +100%
Class 4	L: -15 to -30% H: +20 to +50%
Class 3	L: -10 to -20% H: +10 to +30%
Class 2	L: -5 to -15% H: +5 to +20%
Class 1	L: -3 to -10% H: +3 to +15%

7.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 15

7.1 Please explain more fully what the 30% factor is applied to (e.g., are the engineering, project management, etc. charges to which it is applied the charges just for the "new work").

Response:

For distribution and transmission rehabilitation and rebuild projects, the work is quite similar from an installation and removal standpoint. In general, a new pole or structure is to be installed where an existing one is to be removed. In most cases this involves moving the existing structure and attached facilities enough to put the new pole or structure in. The old pole or structure is then removed. The work to install the new structure as well as a portion of the alteration to stand-off existing facilities to safely place the new structure is considered "new construction". The remainder of the alteration costs as well as the removal of the old facility is considered "cost of removal" (COR).

Following is a listing of how the COR is allocated for the individual components for Transmission Rehabilitation / Distribution Rehabilitation, Rebuild, and Small Planned Capital projects:

- Engineering – 30% of this component is considered design work to establish the salvage of facilities.
- Land and Brushing – 0% is used for COR since land negotiations or brushing is not required to accommodate salvaging of facilities.
- Material – 0% is used for COR since new materials are not required to accommodate salvaging of facilities.
- Project Management/Supervision – 30% of this work is allocated for the safe removal of facilities as well as administration/record-keeping functions to retire the assets.
- Third Party Expense – 30% of this component is allocated to remove facilities. This includes flaggers, backhoe rental charges, etc.
- Construction Labour – 30% of this work is allocated to accommodate the removal of facilities.
- Construction Vehicles – 30% of the vehicle charges are allocated to driving to and from the facility location and completing the salvage component of the work.

7.2 What is the basis for the 30% and 50% factors?

Response:

Please refer to the response to BCOAPO IR1 Q7.1 for a discussion of the 30% factor application

For Transmission / Distribution Urgent Repairs projects, FortisBC considers that a ratio of 50% of the cost components is more representative since these are typically short duration projects where a crew is called to replace damaged facilities. For these short duration projects the time to install the new facilities compared to removing and cleaning up the damaged facilities is considered to be approximately equal. Material, land, and brushing are not included in the cost of removal for the reasons stated in the previous response.

8.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 16 and 17

8.1 Please provide a table setting out the number of substations (transmission and distribution) serving each Region and the total kVA for each.

Response:

The table below summarizes the total number of FortisBC-owned substations and the corresponding winter non-coincident peak in kVA by region. Please refer to the ISP Volume 1, Appendix B (Exhibit B-1-1) for a complete listing of each distribution substation transformer and its respective peak kVA for both summer and winter. There are four additional transmission terminal stations included in the table below that are not listed in Appendix B as they do not serve any distribution load directly.

Table BCOAPO IR1 8.1

Region	Number of Substations (Transmission & Distribution)	Non-coincident Peak kVA (2010 Winter)
North Okanagan	14	298,746
South Okanagan	19	220,777
Boundary	4	42,041
Kootenay	23	173,433
FortisBC	60	734,997

9.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 43-44

9.1 Please provide a revised version of Table 2.5(a) including the total Generation spending for each year/period shown.

Response:

Expenditures by year can be found at page 1, Appendix J of the 2012 Long Term Capital Plan (2012 ISP, Volume 1, Exhibit B-1-1)

9.2 For each of the four major spending categories, please indicate the annual level of capital spending over the period 2005-2011.

Response:

Prior to this filing, work at Generation was categorized as either Major Capital or Minor Sustaining Capital. The four spending categories identified in the ISP were introduced to better describe the nature of the expenditures moving forward. The annual level of capital spending from 2005 to 2011 in Major Captial and Minor Sustaining Capital has been re-classified in the table below.

Table BCOAPO IR1 9.2

		2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
1		**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Forecast**
2		**($000s)**						
3	Physical Infrastructure Projects Total	-	-	533	1,171	-	-	975
4	Mechanical and Electrical Equipment Projects Total	12,594	12,445	19,788	13,739	18,562	17,530	17,234
5	Dam, Public and Worker Safety Projects Total	-	230	497	115	45	(23)	-
6	All Plants Minor Sustainment Projects Total	1,262	998	(416)	1,170	1,056	1,024	634
7								
8	**Total Generation Projects**	**13,856**	**13,673**	**20,403**	**16,195**	**19,663**	**18,531**	**18,843**

Note 1: Cost of removal not included

Note 2: 2007 All Plants Minor Sustainment Project credit of $416,000 due to Provincial Sales Tax audit recovery payment

Note 3: 2010 Dam, Public and Worker Safety Project credit of $23,000 is due to the processing of vendor stale dated cheque

9.3 Please comment on continuity of the spending over the period 2012 to 2016. (i.e. annual levels)

Response:

FortisBC attempts to level its annual capital spending. The higher than average costs in 2012 are the result of $5.6 million of spending from previously approved projects. The remaining projects in 2012 are deemed to be necessary for safety and reliability reasons. The bulk of the costs in 2014 are from the Corra Linn Concrete and Spill Gate Rehabilitation Project. These costs are to ensure the gate access and isolation system is in place to allow the start of gate refurbishment in 2015. This project will be the subject of a future regulatory filing in which further work on schedule and cash flow will be detailed.

9.4 Can any of the projects scheduled for 2012 be delayed to later years in order to provide a more level annual pattern of planned spending?

Response:

FortisBC plans its capital investment projects based on need and attempts to level the pattern of spending where possible. This is evidenced by the consistent sustaining level of investment in programs such as All Plants Concrete and Steel Rehabilitation and All Plants Minor Sustainment Capital. In addition, projects such as All Plants Fire Safety or Plant Automation are spread out over multiple years to level the spending pattern (refer to Table 2.5(a), pages 43-44 2012 Integrated System Plan).

In 2012, approximately $5.6 million of expenditures are related to the completion of multiyear projects. In addition to these expenditures, two additional projects (Corra Linn Unit 3 Completion and Upper Bonnington Old Plant Various Unit Upgrades) account for approximately $2.0 million of expenditures. These projects have been proposed based on need and FortisBC has assessed the risk of delaying these projects as high. As noted in Tab 6, page 15 of the 2012-2013 Revenue Requirements (Exhibit B-1), many components of the Upper Bonnington Old units are approaching 100 years of age and for various reasons require sustaining capital investment to ensure their ongoing safe operation. For example, sealing timbers for the headgates have rotted through creating potential issues for dewatering the units. Some mechanical components such as links and bushings have worn and require replacement to reduce the chance of damage to the unit through excessive vibration. Referring to Tab 6, pp. 14 of the 2012-2013 Revenue Requirements, work on the Corra Linn Unit 3 Completion is required to address several issues with this unit which is deemed to be a high potential risk. The primary issue is the condition of the existing trashracks. If the trashracks were to fail, it could result in the passage of large objects into the wicket gates and turbine, potentially causing extensive damage and forced outage time to the unit. Also included in this project is the need to provide proper oil containment. FortisBC rates transformers in close proximity to water courses as high risk for the purposes of determining the type of containment required.

The balance of expenditures for 2012 total $2.4 million, which compares with a planned expenditure in 2013 of $2.9 million.

9.5 How does FortisBC plan to resource (e.g. labour) the high level of capital spending planned for 2012 (relative to later years)?

Response:

FortisBC will continue to use a combination of temporary employees and contract labour and services to deliver the capital program in 2012. This approach is consistent with the resourcing strategy used over the life of the Upgrade Life Extension program.

10.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 50-51 and 13

10.1 Please confirm that all the costs shown in the 2012 LTCP are in nominal dollars based on a 2% annum escalation over costs in 2010 $.

Response:

Confirmed.

10.2 Please reconcile the statement at page 50 regarding concerns for future cost escalation with the planning assumption (per page 13) of an assumed CPI increase of 2%/annum.

Response:

The discussion on page 50 refers to the estimated escalation of the actual deterioration at the facilities, not the escalation of material and labour costs discussed on page 13. An increase in deterioration at the plants results in higher construction costs as the scope of work to repair the deterioration increases.

10.3 For those projects with previous BCUC approval (e.g., G-195-10), please indicate whether the current cost estimate differs from that associated with the original approval? If there is a variance, please explain why.

Response:

At the time of this regulatory filing, there is only one project with previous BCUC approval in which the current cost estimate differs from the original approval. Corra Linn Unit 2 Life Extension is forecast to be under budget by approximately 1 percent.

11.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 54

11.1 Please confirm that the 2013 spending on the Lower Bonnington Powerhouse Windows is part of the project approved by G-195-10.

Response:

Yes, the 2013 spending on the Lower Bonnington Powerhouse Windows is part of the project approved by G-195-10.

12.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 54-55

12.1 Has a formal assessment been undertaken as to the current condition of the Corra Linn Spillway Gates and the criticality of the planned repairs? If yes, please provide.

Response:

Work is underway to assess the current condition of the Corra Linn Spillway to determine both the timing of rehabilitation and the scope of work. As part of this assessment, onsite work was completed during the week of July 8, 2011 to conduct wet and dry visual gate inspections. This onsite work will support an engineering assessment which will include a preliminary analysis of different load cases and failure probabilities for the spill gates. The outcome of this assessment will provide the Company with an engineering report for the spill gates which will include recommendations for immediate work as well as long term rehabilitation recommendations and will assist FortisBC in determining the criticality and timing of repairs or rehabilitation. The engineering assessment is scheduled for completion by the end of 2011.

13.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 57

13.1 Are there no economies to be gained from undertaking the rehabilitation of the head gate and spill gate superstructures at the same time as the spill gates themselves are rehabilitated?

Response:

There would be some minor economies to be gained from undertaking the rehabilitation of the superstructures in conjunction with gate rehabilitation, however the timing of the need for the rehabilitation prevents the majority of any economies from being realized. For instance, many of the head gates were refurbished only a few years ago and will not require rehabilitation for many years.

It will be more costly to allow additional deterioration until the next cycle of head gate refurbishment than to repair structural deficiencies at this time.

14.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 60-61 and 39.

14.1 With respect to the Upper Bonnington Old Plant Various Units Upgrades spending in 2013, it is noted that there is no further spending contemplated on this station in subsequent years. Would any additional major sustainment spending be required prior to the planned rebuild in 2020?

Response:

The work planned in 2013 is intended to address safety and equipment concerns required to ensure safe and cost effective operation of the old units. There is no major sustainment work planned prior to the rebuild, however given the age of the units it is conceivable that equipment condition may require attention prior to 2020 or advancement of the planned rebuild.

14.2 On page 39, it is noted that there is no planned rebuild date but on page 62 there is a reference to a planned repowerment with an in-service date in 2020. Please reconcile.

Response:

As noted on page 39 the timing of any rebuild project at Upper Bonnington will be dependent on the condition of the component parts and the Company's ability to continue to operate the units in a safe, reliable and cost effective manner. 2020 is an estimated date for the purpose of representing this project within the long term plan.

15.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 61

15.1 When is the business case for the plant automation at these three facilities expected to be completed?

Response:

The business case for plant automation at the three facilities is expected to be completed in 2013 in time for the filing of Company's next Capital Expenditure Plan.

15.2 Section 2.5.2.6 starts with a discussion of time-based vs. condition based maintenance. Please explain the link between this issue and plant automation.

Response:

The scope of the plant automation project includes the installation of equipment designed to permit the monitoring and communication with generation equipment in the plant remotely. The benefits to the project include the ability to monitor the condition of important components, as well as the potential to remotely diagnose issues through communication with plant equipment.

One key component in the shift from a time-based to a condition-based maintenance program is the ability to track and trend equipment condition over time to determine the optimal point for maintenance. The plant automation project will provide the ability to track this information, thereby enhancing the ability of the Company to transition to a condition-based maintenance approach.

16.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 61-62

16.1 Will the future spending plans for All Plants Heating and Ventilation be supported by a business case prior to implementation?

Response:

Yes.

17.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 80

17.1 Are the regional load forecasts used for transmission planning "net" of DSM? If not, why not?

Response:

Yes. As discussed in the 2012-13 RRA, Tab 3, Appendix 3F, Page 4, in planning the bulk transmission system, FortisBC uses a load forecast with DSM impacts included. DSM resources have a more predictable impact at the bulk transmission level than at any local area level, due to (1) regional load diversity and (2) difficulties in allocating DSM deliveries to local circuits and distribution feeders. In local area transmission and distribution planning studies, a load forecast without DSM impacts is used initially and if project timing is deemed to be very sensitive to load, DSM considerations are included in a sensitivity study to determine potential impacts on transmission and distribution projects. As more information is gathered on allocations of DSM resources to local area networks, DSM will be included in local area transmission and distribution studies.

18.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 81

18.1 The text (line 29) states that longer term projects will be subject to further reviews. Please clarify what is meant by "longer term" in this context (i.e. for how far out is the timing of the planned expenditures portrayed in Table 2.8 (a) reasonably certain?).

Response:

In general, the phrase "longer term" is referring to projects beyond the five year horizon (i.e. projects that are currently proposed for 2017 and beyond). However all of the transmission, stations and distribution projects listed are potentially subject to advancement or deferral based on the actual rate of customer load growth.

19.1 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 79-80 and 82-84

19.1 Page 79 describes how the transmission system is planned to meet N-1 conditions which requires load be met following the loss of a single bulk system component. Given that this planning criterion assumes no customer outages under N-1 conditions, please explain how the cost of customer outage (per pages 82-84) is factored into transmission planning component.

Response:

While not routinely used by FortisBC in transmission planning, reliability cost analysis has been previously used in specific instances as an additional consideration. Some example scenarios include:

1. Customer outages can arise under N-1 conditions in load areas served by radial lines. The BC Mandatory Reliability Standards exclude these configurations from N-1 compliance. However, reliability studies can be used to determine if infrastructure upgrades are justified to improved customer reliability.

2. Reliability studies can be used to evaluate the relative merits of system reinforcement options. For example, alternate substation configurations may result in different levels of system performance due to the reliability of individual substation components while still meeting N-1 compliance. A quantitative assessment of these performance differences versus the capital costs of the options can be used in the determination of an optimal solution.

3. Customer outages can also arise from N-2 and multiple contingencies. While FortisBC does not generally plan to this level, in the evaluation of transmission investments or

other alternatives, it is important to include the cost of customer outages in the cost/benefit assessment of each alternative.

20.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 86

20.1 Will FortisBC's assessment of future transmission requirements and options (particularly for the Okanagan region) include the consideration of generation options as an alternative?

Response:

Yes – as described in Section 2.7.7 of the Long Term Capital Plan (Exhibit B-1-1), potential generation additions in the Okanagan region will be evaluated against possible transmission solutions when the need for system reinforcement becomes more imminent.

21.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 86-87

21.1 How much of FortisBC's load is currently supplied via a Radial configuration and does not meet the N-1 planning criterion? (Note: It is recognized that due to the existence of local generation some load centres with radial supply may meet N-1 planning criteria.)

Response:

The following substations are served via a single radial transmission line and thus cannot meet the N-1 transmission planning criterion. Note that no load centers have local generation. Also shown for reference is the forecast 2011 Winter Peak load for each substation and the percentage of the total distribution non-coincident Winter Peak load for that year (820,771 kW).

Table BCOAPO IR1 21.1 – Radially Supplied Substations and Associated Peak-Load

Substation	2011 Forecast Winter Peak Load (kW)	% of Non-Coincident Winter Peak Load
North Okanagan		
Duck Lake (DUC)	42,050	5%
Ellison (ELL)	14,988	2%
Joe Rich (JOR)	3,330	0%
Big White (BWS)	16,281	2%
Region sub-total:	**76,649**	**9%**
South Okanagan		
Summerland (SUM)	18,499	2%
Trout Creek (TRC)	7,261	1%
West Bench (WEB)	8,833	1%
Arawana (AWA)	7,413	1%
Westminster (WES)	24,683	3%
Waterford (WAT)	17,760	2%
Pine Street (PIN)	22,681	3%
Osoyoos (OSO)	12,481	2%
Nk'Mip (NKM)	10,690	1%
Region sub-total:	**130,301**	**16%**
Kootenay		
Passmore (PAS)	3,520	0%
Valhalla (VAL)	9,468	1%
Creston (CRE)	26,640	3%
Kaslo (KAS)	9,189	1%
Region sub-total:	**48,817**	**6%**
Boundary		
Christina Lake (CHR)	4,968	1%
Ruckles (RUC)	15,683	2%
Region sub-total:	**20,651**	**3%**
Total radial load:	**276,418**	**34%**

22.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 89-90

22.1 Please identify those projects in Table 2.8 (a) for which the BCUC has already granted approval and the relevant Order.

Response:

Please refer to Table BCOAPO IR1 22.1 below for the list of projects listed in Table 2.8(a) of the 2012 Long Term Capital Plan previously approved by the Commission.

Table BCOAPO IR1 22.1

Project	Order
Okanagan Transmission Reinforcement	C-5-08
Ellison to Sexsmith Transmission Tie	Engineering and Estimating Costs approved by Order G-195-10
Environmental Compliance (PCB Mitigation)	2011 expenditures approved by Order G-195-10
Add Arc Flash Detection to Legacy Metal-Clad Switchgear	2011 expenditures approved by Order G-195-10

22.2 Please identify those Transmission Growth projects that are triggered by future load growth (as opposed to being required based on current load levels). In each case, please identify the year when the load growth is expected to "trigger" the need.

Response:

The table below lists all growth related transmission and station projects and the year when the need for each project is triggered by load growth:

Table BCOAPO IR1 22.2 – Transmission Growth Projects by Year

	Transmission Growth Project	Year
1	42 Line Meshed Operation (Huth and Oliver)	2014
2	Kelowna Bulk Transformer Capacity Addition	2015
3	Capacitors at Bentley Terminal	2016
4	Summerland Substation Transformer Upgrade	2016
5	RG Anderson Distribution Transformer Upgrade	2017
6	Reconductor 52 Line and 53 Line	2018
7	Beaver Valley Solution	2018
8	DG Bell Static VAR Compensator	2018
9	FA Lee Distribution Transformer Addition	2019
10	New Central Okanagan Station	2019
11	New Enterprise Substation	2021
12	Sexsmith Second Distribution Transformer Addition	2021
13	Saucier Second Distribution Transformer Addition	2022
14	Stoney Creek Second Distribution Transformer Addition	2024
15	Vaseux Lake Third 500/230 kV Transformer	2025
16	Boundary Area Supply	2025
17	Creston Area Capacity Increase	2025
18	Playmor 25 kV Distribution Transformer Addition	2027
19	Ellison Second Distribution Transformer Addition	2027
20	Benvoulin Second Distribution Transformer Addition	2028
21	DG Bell Second Distribution Transformer Addition	2028
22	DG Bell 230 kV Ring Bus	2030
23	DG Bell Second 230/138 kV Transformer	2030
23	Reconductor 31 Line (Creston Area)	2030
24	Reconductor 51 Line and 60 Line (DG Bell to OK Mission)	2030
25	Reconductor 50 Line Recreation to Saucier)	2035
26	Reconductor 50 Line (FA Lee to Springfield Tap)	2035
27	Reconductor 54 Line (DG Bell to Black Mountain)	2035

23.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 91

23.1 Will FortisBC be making a new CPCN application for the Ellison to Sexsmith Transmission Tie? If not, why not?

Response:

No, FortisBC does not believe that a CPCN application is required for this project. The criteria that FortisBC uses to determine the need for a CPCN application are:

1. The project cost is $20 million or greater; or
2. The project is likely to generate significant public concerns; or

3. FortisBC believes for any reason that a CPCN application should proceed; or
4. After presentation of a Capital Plan to FortisBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application, or
5. The Commission determines that a CPCN application should proceed..

Given these criteria, FortisBC does not intend to submit a further CPCN application for the Ellison to Sexsmith Transmission Tie.

In Order G-195-10 and the associated decision, the Commission found that a design phase project to improve the reliability for the 9,700 customers in this area is in the public interest. FortisBC is on schedule to complete this design work by the end of 2011. The current cost estimate to complete the project construction is approximately $7.5 million. Many of the existing structures in the line corridor have an overbuilt transmission circuit which was previously energized at 63 kV, and thus the appearance of these pole structures will not change significantly. No public concerns related to the transmission line construction or routing were expressed during the previous 2011 Capital Expenditure Plan regulatory process, nor is FortisBC aware of any to date.

Given this information and the potential for significant impacts on customer reliability due to single contingency outages of the current transmission supply, FortisBC is proposing the construct the project in 2012/13.

23.2 What was the original cost of the project as approved in Order C-4-07? How does this compare with the current estimate of $7.534 M (2010$)?

<u>Response:</u>

The original estimate for the Ellison to Sexsmith Transmission Tie contained in the Ellison Substation Project CPCN application was $3.86 million in 2010 dollars. That estimate was developed in 2006 prior to recent commodity price inflation and was based on a conceptual design only. The current estimate is based on a detailed review of the required substation and transmission line construction and current market costs.

24.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 94-101

24.1 FortisBC states (page 94) that it is only seeking approval for expenditures related to the relocation and storage of the transformer at the Grand Forks Terminal and for the construction of the fibre optic link. Please confirm that this is the approval being sought under Tab 6 of the 2012-2013 RRA (page 38).

Response:

As stated on Tab 6 (page 38) of the 2012-13 RRA, the specific project tasks for which FortisBC is seeking approval are expenditures related to the relocation and storage of the transformer at the Grand Forks Terminal, the condition assessment of 9 and 10 Lines, and the construction of the fibre optic link between Grand Forks and Warfield.

24.2 What are the relative costs (after allowing for incremental revenues) of the three options described on page 100?

Response:

Please refer to the response to BCUC IR1 Q127.1.

24.3 What is the value of the ex-Oliver unit if not used as part of this project? How has this been accounted for the cost comparison provided in response to the previous question?

Response:

If not used in some way at Grand Forks, the transformer would be of no use to FortisBC and would consequently be scrapped. Based on recently completed transformer salvage projects, any scrap material value of the transformer would likely be offset by the cost to salvage the unit. In other words, if the transformer is not used at Grand Forks, the transformer asset value is essentially zero.

The transformer is in fair condition; however, some rehabilitation costs have been allowed for in the project estimate. If the transformer was scrapped and a new unit purchased instead, then the full incremental costs beyond the estimated value of the rehabilitation work would be incurred by the project. Based on current estimates for a new transformer this cost could exceed $1 million. On that basis, FortisBC did not develop any project estimates which included the purchase of a new transformer.

25.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 108

25.1 Page 108 identifies a number of issues with the reconductoring phase of the project – which is now scheduled for 2017. Are the three phases linked (i.e., should the problems identified with the third phase prove unresolvable/extremely costly, are there alternatives to the reconductoring that are compatible with the first two phases)?

Response:

The most significant issue which arose when the need for this project was originally identified was a request from the Penticton Indian Band to relocate a segment of the existing transmission lines. Portions of the existing FortisBC right-of-way passes through First Nations land and the Band has proposed development of a residential subdivision in this area. To maximize the development potential for this land the Band has proposed relocating a number of existing transmission line structures. A new line route is still being evaluated and negotiated. It is expected that if the final rerouting is carried out as part of the reconductoring project the incremental costs would be minor. Further discussions with the Band are required to resolve this issue.

The riparian zone right-of-way, where the lines are currently located, will require obtaining the appropriate environmental permits in advance of construction and is not expected to be a significant incremental cost.

Finally, an appropriate cost allocation between FortisBC and the City of Penticton will need to be determined to apportion the costs related to the relocation of the existing City-owned distribution circuits located on FortisBC's transmission structures.

These complications are not believed to be irresolvable or present significant cost impacts for this project but were not resolvable in time for the project to be proposed in the 2012 – 13 Capital Plan. There are no other cost-effective alternatives known at this time that could increase the capacity of 52/53 Line transmission path between the R.G. Anderson Terminal and the Huth substations.

Finally, it should also be noted that future deferral or cancellation of the 52/53 Line reconductor project does not create stranded assets of the first two phases. The first two phases are required independent of the 52/53 Line reconductoring to reliably source the forecasted loads and meet the transmission planning criteria into the future. Combined, all three provide ample capacity to the transmission network in the South Okanagan beyond the 20 year horizon.

25.2 If the three phases are closely linked, why is it appropriate to undertake the first two phases prior to resolving the issues associated with the reconductoring?

Response:

By "closely linked," the meaning is that each phase of the upgrade influences the other in terms of timing. The phases are not linked in terms of scope or location. Therefore the issues identified for the reconductoring phase are not related to the other two phases. Refer also to the response to BCOAPO IR1 Q25.1.

26.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 109

26.1 Table 2.8(a) does not contain any costs in 2012/13 for the Meshing Kelowna Loop. Please confirm that the related spending is set out at line 2 of Table 4.3. If not, where are these costs included?

Response:

The expenditures appearing at line 2 of Table 4.3 (Kelowna 138 kV Loop Fibre) are the telecommunications infrastructure (fibre) costs associated with the "Meshing Kelowna Loop" costs appearing at Line 8 of Table 2.8(a). The former project will improve communications in the Kelowna area and will support the future initiative to implement the Meshing Kelowna Loop project (transmission protection). However, the future meshing project is not required by the fibre addition project and will be justified on a standalone basis in a future Capital Plan application.

27.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 109

27.1 How is the salvage/resale value of the existing transformer reflected in the $6.58 M cost?

Response:

The remaining asset value of the existing transformer is not currently reflected in the $6.58 million cost. Following the installation of the new unit, the condition of the existing transformer will be assessed. If the condition of the unit is good and there is the potential for reuse of the transformer at another location, then the transformer would be transferred to equipment stores (Spare Parts asset class). If it is determined that the unit has significant condition issues or there is no other location where the transformer could be used then the unit would be scrapped.

Based on recent transformer salvage projects the scrap material value is expected to be offset by the cost to salvage the unit. Thus, the determination of the value of the existing transformer will be made following removal of the unit and the condition assessment thereof.

27.2 Does the supply agreement include any commitment on Summerland's part to minimum load levels or a capital contribution requirement?

Response:

The Wholesale supply agreement with the City of Summerland does not set a minimum recorded load level for the municipal utility.

There is no capital contribution requirement within the agreement however there is a Revenue Guarantee provision related to capital contributions in certain circumstances which states that Summerland may be required to provide a revenue guarantee if FortisBC's facilities must be upgraded significantly to meet a proposed increase in Summerland's load in excess of 5000 kVA resulting from either a new Summerland customer or the increased load of an existing Summerland customer. The revenue guarantee will be equal to the cost of upgrading the facilities and will be refunded, with interest, in equal installments over a period of five years at the end of each year of continued service to that customer at the increased load.

28.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 113

28.1 Does the supply agreement include any commitment on Penticton's part to minimum load levels or a capital contribution requirement?

Response:

Please see the response to BCOAPO IR1 Q27.2. Penticton and Summerland have the same contractual obligations.

29.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 113

29.1 Does FortisBC plan to review the cost of the various upgrade options available for the DG Bell Terminal prior to proceeding with the currently preferred option for 2018?

Response:

Yes – for all projects beyond 2012-13 (the interval for which FortisBC is seeking approval), the need and timing for each project will be reviewed based on any new information which becomes available in the future.

29.2 On a more general level, for all those projects currently planned to go in-service post 2013, is it FortisBC's intention to re-assess the alternatives available prior to proceeding?

Response:

Yes. Please refer also to the response to BCOAPO IR1 Q29.1.

30.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 121

30.1 In Section 2.8.21.2, the second paragraph suggests that the existing Glenmore Substation would be unable to handle some of the preliminary service requests that FortisBC has recently received. However, the third paragraph states that the substation has sufficient capacity to meet area loads until 2020. Please reconcile and, in doing so, clarify the following:

30.1.1 Are the recent service requests reflected in the current load forecast?

Response:

FortisBC has received preliminary inquires related to the addition of new data center loads in the Kelowna area. The specific load requirements, siting and timing of these projects are very uncertain from FortisBC's perspective and thus are not included in current load forecasts. The load growth rate applied to the current load forecast is expected to be accurate given the growth rates and patterns expected at this time.

30.1.2 Whether the reference to "sufficient substation capacity" is strictly with respect to transformer capacity (e.g. kVA) and does not reflect the current limitation on adding additional feeders.

Response:

The reference to "sufficient substation capacity" excludes the potential large load additions associated with prospective major data center projects. As discussed in the response to BCOAPO IR1 Q30.1.1 these customer projects are highly uncertain at this time. If major new distribution loads materialize in the area supplied by the Glenmore substation, then the substation could be constrained both by transformer capacity limitations and space limitations in terms of adding new feeder positions.

30.1.3 How would FortisBC address current system limitations if one of the tentative data center customers (with load > 5 MW) formally requested service in the near future?

Response:

Solutions to address new customer load additions larger than 5 MW would be highly dependent on the timing and size of the new service request. If the growth can be staged over a period of time then new load could potentially be accommodated by the addition of new distribution equipment which would be included in the Distribution New Connects program and offset by a Contribution In Aid of Construction (CIAC) from the customer. For larger load requirements, it may be advantageous for the customer to interconnect with the FortisBC transmission system to avoid the large capital costs associated with increasing the area substation capacity.

31.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 128-130

FortisBC 2012-2013 Revenue Requirements Application, Tab 6, pages 42-47

31.1 Please confirm that the values reported in ISP Table 2.9 as well as Tables 2.9.1 - 2.9.4 are in nominal $ for the year indicated.

Response:

All values reported in Table 2.9 and Tables 2.9.1-2.9.4 are in 2010 dollars inflated by a 2% CPI to the year indicated.

31.2 Please demonstrate how the "rolling average approach" (per ISP, page 129, lines 7-8) was used to establish the Line Condition Assessment spending for 2012 and 2013.

Response:

The wording in the 2012 Long Term Capital Plan is incorrect. The rolling average approach is used to determine a cost per structure for the Transmission Rehabilitation budget, not the Condition Assessment budget. The wording in the 2012 – 13 Capital Plan document, page 43, lines 5-8 is correct under Transmission Condition Assessment. "The estimates for 2012 and 2013 are derived by applying a total cost required to assess the structure (based on historical information and contractual agreements) to the number of transmission poles being assessed. This number is then adjusted for inflation and overhead loading."

Page 129 of the 2012 Long Term Capital Plan has been corrected in Errata No. 2.

31.3 Please explain the substantial increase in annual spending on Line Rehabilitation in 2012 and 2013 relative to earlier years.

Response:

As outlined in the referenced section of the 2012 – 13 RRA on lines 6-8, page 45, "the estimates for this budget are based on historical information of costs on a per pole basis, adjusted for inflation and changes to overhead loading, and knowledge of the transmission line being assessed". The graph on the same page outlines that almost 1/3 of the Company's transmission poles are 50 years old or older. The average life expectancy of a transmission pole in the FortisBC system is 40-60 years, therefore the budget for 2012 and 2013 was increased to account for the higher amount of poles expected to need replacement.

31.4 Please demonstrate how the "rolling average approach" (per RRA, page 46, lines 9-128) was used to establish the Urgent Repairs spending for 2012 and 2013.

Response:

Please refer to the response to BCUC IR1 Q132.4.

31.5 Please explain the forecast increase in annual spending on Line Right of Way Easements relative to historical levels (per RRA, page 47).

Response:

Please refer to the response to BCUC IR1 Q133.4.

32.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 140-141

FortisBC 2012-2013 Revenue Requirements Application, Tab 6, pages 60-61

32.1 Please explain the increase in annual spending on Station Urgent Repairs in 2012 and 2013 relative to earlier years.

Response:

The increase in forecast spending on Station Urgent Repairs is due to the method of calculating this budget. The budget is calculated using a three year rolling average, using an average of the last three years unloaded budget expenditures. The 2012 budget was derived from the expenditures from 2010, 2009 and 2008. In 2008, the Summerland substation transformer failed and required repairs, causing an increase in the Station Urgent Repair spending. In 2009, a bus fault at the Creston substation and circuit breaker failure at the A.A. Lambert Terminal resulted in increased expenditures for that year. These events and associated expenditures result in an increase in the three-year rolling average.

An error was discovered in the calculation of the forecast expenditures for 2012 and 2013 during the preparation of this response, as such the forecast expenditures for Station Urgent Repairs for 2012 and 2013 has been adjusted from $0.818 million and $0.907 million in each year to $0.811 million and $0.808 million respectively. Please refer to Errata 2.

32.2 Please explain the increase in annual spending on Station Assessment and Minor Planned Projects in 2012 and 2013 relative to earlier years.

Response:

The apparent increase in annual spending on Station Assessment and Minor Planned Projects in 2012 and 2013 relative to earlier years (specifically 2009 and 2010) is due to the way the expenditures were reported. The actual costs reported in Table 3.3.3 of Tab 6 do not include expenditures for DC Supply Upgrades which are include in the requested amounts for the current program. Please see Table BCOAPO IR1 32.2 below for detail on the 2009 and 2010 expenditures for these projects.

Table BCOAPO IR1 32.2

	2009	2010
Description	**($000s)**	
Station Assessment and Minor Planned Projects	286	286
DC Supply Upgrades	451	150
Total	**737**	**436**

33.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 160

FortisBC 2012-2013 Revenue Requirements Application, Tab 6, page 67

33.1 Please explain the higher forecast spending for Distribution New Connects in 2012 and 2013 relative to the historical average.

Response:

The historic values shown in Table 4.1.1 of the 2012/2013 CEP document are net values and include customer Contributions In Aid of Construction (CIAC). Contributions in Aid of Construction include those from New Connections, Forced Upgrades and any other CIAC received. The three year rolling average calculation is based on the historic actual New Connect expenditures including New Connect CIAC only. The Company did not forecast the CIAC from Forced Upgrades and other sources for 2012 and 2013.

34.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 169-171

FortisBC 2012-2013 Revenue Requirements Application, Tab 6, pages 74-78

34.1 Please explain what drives the materially higher forecast 2012 and 2013 spending on each of the following programs:

- Distribution Line Condition Assessment,
- Distribution Line Rehabilitation (particularly 2012), and
- Line Rebuilds (relative to 2008-2010)

Response:

There are three primary drivers of an increase in the requested budget in the 2012/2013 plan for the Distribution Condition Assessment project as detailed below:

1. FortisBC is increasing the number of poles being condition assessed each year to more accurately account for 1/8th of the Distribution system. This will eliminate feeders or portions of feeders from not being assessed within an eight year cycle.
2. FortisBC is revising the Distribution Condition Assessment program (see Appendix I in ISP – Volume 1, Exhibit B-1-1) to provide more detailed knowledge of asset health to enable planners to produce more accurate Distribution Rehabilitation budgets. Beginning in 2012, the preparation of the rehabilitation design packages will be included as part of the Condition Assessment scope of work instead of the rehabilitation scope of work to improve construction scheduling and budget planning.
3. Corporate loadings have increased since 2010.

The increase in the 2012 Distribution Rehabilitation budget is driven by the increased number of poles being condition assessed in 2011 to "catch up" the feeders that were not assessed in the last eight year cycle. As well, there is carryover work from the 2011 rehabilitation projects that has been added to the 2012 rehabilitation scope. The amount requested in 2012 is estimated to capture all of the 2011 carry over work and the full scope of 2012 rehabilitation work.

The budget for Distribution Line Rebuilds is not based on a three year rolling average and therefore the 2008-2010 expenditures do not have any influence on the 2012/2013 budgets. The increased expenditures (relative to 2008-2010) are simply driven by the type of distribution line rebuild projects identified for 2012 and 2013. Every project within this budget has been estimated and the costs (adjusted for loadings and inflation) are considered consistent with historical spending.

35.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 159 and 173

35.1 Page 173 makes reference to expenditures of $27.4 M being required to meet station equipment compliance by December 31, 2014. However, Table 3 does not show any spending on this program over the period 2012-2014. Please reconcile.

<u>Response:</u>

Table 3.0 – Distribution Projects lists expenditures required to achieve compliance with the *PCB Regulation* year 2025 deadline associated with distribution pole-top and pad-mount electrical transformers and other electrical equipment located outside of substations. The $27.4 million in expenditures referred to on page 173 is for substation equipment replacements and is identified on line 1 of Table 2.10, page 138 of the 2012 Long Term Capital Plan.

36.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 181-185

FortisBC 2012-2013 Revenue Requirements Application, Tab 6, pages 81-93

36.1 With respect to ISP Table 4.3.1.1, please explain why Option F is deemed as requiring "No Reliance on Third Party" when it will involve the use of leased facilities.

Response:

There is a fundamental difference between leasing communications facilities versus leasing communications services from a third party.

In the former case, the physical infrastructure (such as a fibre optic cable) may be owned by a third party, but FortisBC has dedicated access to a portion of the facilities (such as "dark" fibre strands), and has physical access to it in the event of a failure or other problem. There is no need to rely on technicians or staff from other organizations to diagnose and repair equipment issues.

In the latter case, leased communications services involve the use third party equipment that is serviced and maintained by non-FortisBC technicians. FortisBC does not have control over when and how maintenance is performed, and in many cases isn't informed prior to this work being conducted. Furthermore, FortisBC has no control over how quickly and with what resources failures are responded to.

Option F uses leased fibre optic cable (dark fibre), therefore FortisBC has control over how and when physical access to the fibre occurs, what equipment is on both ends of the fibre and has the ability to designate the response needed in the event of a failure.

36.2 How does Option F differ from Option D which also relies on leased facilities and is deemed as not satisfying the "No Reliance on Third Party" criterion?

Response:

Option D involved leasing communication services from a third party provider whereas option F proposes leasing communications facilities (infrastructure). Please refer to the response to BCOAPO IR1 Q36.2 for a clarification of the differences.

Option D would use leased communications services, which relies on third part resources, responses, and equipment and thus FortisBC would have no control over the maintenance and operations of these communications circuits.

36.3 Is there any opportunity for FortisBC to lease parts of its new fibre system to third parties?

Response:

For the new fibre installed as part of the Kelowna 138 kV Loop Fibre Installation project, FortisBC-owned fibre will be limited and non-contiguous as it fills in gaps where a third party provider does not have infrastructure. This combined with the fact that there are other fibre alternatives in the area likely makes the new FortisBC fibre uninteresting to third parties. FortisBC has not approached third parties in the area for these reasons; however, the Company would be willing to consider leasing surplus fibre in this area if the opportunity arose.

Opportunities do exist to lease unused fibre strands between Grand Forks and Warfield, as discussed in section 2.8.3 of the 2012 Long Term Capital Plan (2012 Integrated System Plan, Volume 1, Exhibit B-1-1).

37.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 187 and 189

37.1 Please explain more fully why the planned level of redundancy (Sections 4.3.1.2 and 4.3.1.4) is required and the impact it will have on reliability in these two circumstances.

Response:

FortisBC does not see an immediate need for installation of equipment to make the Kootenay and Okanagan Remedial Action Schemes fully redundant. The projects have been included in the Long Term Capital Plan based on projected future changes to the BC Mandatory Reliability Standards requirements that will make it more difficult to take the RAS systems out of service for maintenance and testing without a backup system being available. FortisBC will continue to monitor the drivers for these projects and will seek approval in a future Capital Expenditure Plan if and when the need arises.

38.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 199

38.1 To what extent are the current development costs and will any future capital spending on the Okanagan Long Term Solution be shared with the FortisBC gas division?

<u>Response:</u>

The current development costs for the Okanagan Long Term Solution are solely FortisBC costs to develop options to address the ongoing space and safety issues for FortisBC's existing Kelowna facilities. At this time, FortisBC does not see an opportunity for pursuing an amalgamated site for both companies due to limited industrial land in the Company's preferred location and current land and development costs. For that reason it is unlikely FortisBC Energy (FEI) would share in any future development costs for the development of the Okanagan Long Term Solution. If a solution does become available that involves FortisBC Energy (FEI), then both utilities will obtain the necessary regulatory approvals.

39.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 200

39.1 Please indicate where in the Revenue Requirement part of the current Application the anticipated $600,000 in annual savings is captured.

<u>Response:</u>

The Enterprise lease costs support both operating and capital projects. $0.25 million is allocated to O&M Expense and the remainder to capital projects loading. The impact of the expiring Enterprise lease was inadvertently omitted from the Facilities O&M Expense (Table 4.3.4.14 at page 79 of Tab 4, 2012-13 RRA). The Company will incorporate this reduction in the final calculation of rates.

40.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, pages 206-207

40.1 Do the replacement numbers and capital spending refer only to FortisBC's "owned" vehicles?

<u>Response:</u>

Yes.

41.0 Reference: FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, Appendix F, page 13

41.1 The text states that the data for 2011 is incomplete. How many months of actual data for 2011 are reflected in Figure 1?

Response:

The 2011 data includes actuals to April 30, 2011.

41.2 Please provide a figure similar to Figure 1 for the 21-24 Lines.

Response:

A graphical representation was not provided for this project as there were only two recorded outages within this group of lines over the past 5 years (2007 – 2011). These lines are built with short span lengths and, should something fail on the pole, would remain energized as the conductor would likely not hit the ground. These situations are most often reported by the public since the lines are routed alongside a main highway, allowing FortisBC to isolate in a controlled manner without any protective devices tripping, repair and return the lines to service.

As outlined in the engineering assessment the majority of the poles are 1950s vintage, and as a result, a large number of the poles are stubbed or in overall poor condition and will require replacement to ensure system integrity. FortisBC believes that these lines need to be corrected before larger outages begin to occur.

42.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, page 1

42.1 How does FortisBC define "self-sufficiency" within the context of its Resource Plan? In particular, please indicate which resources FortisBC currently utilizes and/or plans to utilize that would not "count" as contributing to self-sufficiency and explain why.

Response:

"Self-sufficiency" for the purpose of the 2012 Long-Term Resource Plan is defined as the FortisBC resource gap being materially addressed in the long-term through long-term firm supply contracts sourced solely from electricity generating facilities within the Province (such as the BC Hydro 3808 Power Purchase Agreement, the Brilliant Power Purchase Agreement and the Waneta Expansion Capacity Purchase Agreement), or the ownership of physical generation resources located within BC where the power is first committed to FortisBC supply (such as the four FortisBC plants on the Kootenay River).

43.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, pages 4-5 and pages 54-55

43.1 With respect to Figure 1.2.2, do the High and Low forecasts shown depict the range of possible DSM contribution, as discussed on page 5? If not, what do they represent?

Response:

The Monte Carlo analysis used to generate the High and Low forecasts in Figure 1.2.2 took into account both the uncertainty in the underlying load forecast before consideration of DSM savings and a range of possible DSM savings. For further information, please refer to Section 4, page 42, Section 5.1.4, page 52 (Exhibit B-1-2), and the responses to BCUC IR1 Q261.1 and BCUC IR1 Q261.2.

43.2 Per page 54, the 5% Load Responsibility allowance in the PRM is meant to address load forecast uncertainty. Over what time-frame is the 5% factor considered to be appropriate given the load forecast uncertainty will increase as the horizon of the forecast period increases?

Response:

The 5 percent Planning Reserve Margin allowance for load forecast uncertainty is based on the expected load forecast. While it is true that the farther out in time the forecast, the greater the uncertainty, it is also true that it is relatively easy to adjust to uncertainties in the timing of new resource development through relatively small market based purchases. Therefore, while it may not be prudent to rely on a market based product for the entire expected resource requirement, it is very reasonable to use a market based product as a short-term adjustment to any relatively minor resource shortfalls that may occur due to long term forecast uncertainties. Given this, it is not critical that the PRM be of sufficient size to cover all load forecast uncertainty into the future. Therefore, the Company feels that the 5 percent allowance is appropriate over the life of the Resource Plan. As the Company reviews new resource requirements in future Resource Plans, any required adjustments in new resource development will be made.

44.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, Appendix D, pages 7 and 21 of 35

44.1 One of the purposes of the PRM is to address load growth uncertainty. Given this objective, why is the "Load Responsibility" adjusted for firm sales and firm purchases? For example, a significant amount of firm purchases would reduce the net amount expected to be supplied by FortisBC resources but would increase the variability of this amount, as the load forecast uncertainty applies to the total load (prior to purchases).

Response:

"Load Responsibility" is adjusted for firm sales and firm purchases because the buyer of a firm block of power does not need to carry the associated reserves. It is the responsibility of the seller to guarantee the un-interrupted supply of their product and therefore they must carry the appropriate reserves to do so. For example, in the FortisBC context, the 200 MW of capacity available through BC Hydro's 3808 PPA is considered a firm purchase into the future and therefore BC Hydro is responsible for carrying the associated reserves. Adjusting load responsibility in this fashion mitigates costs that ratepayers would otherwise be required to bear if additional resources were sourced as reserve for firm purchases.

45.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, page 6 and Tab D page 21 of 35

45.1 Please provide a figure similar to Figure 1.2.5-A for the years 2014 (immediately before the WAX CAPA comes into effect) and 2015 (after the WAX CAPA) comes into effect.

Response:

Please see the figures provided below. The Powerex CAPA will be terminated when the WAX CAPA begins supplying capacity in 2015.

Figure BCOAPO IR1 45.1a - 2014 Monthly Capacity Load/Resource Balance

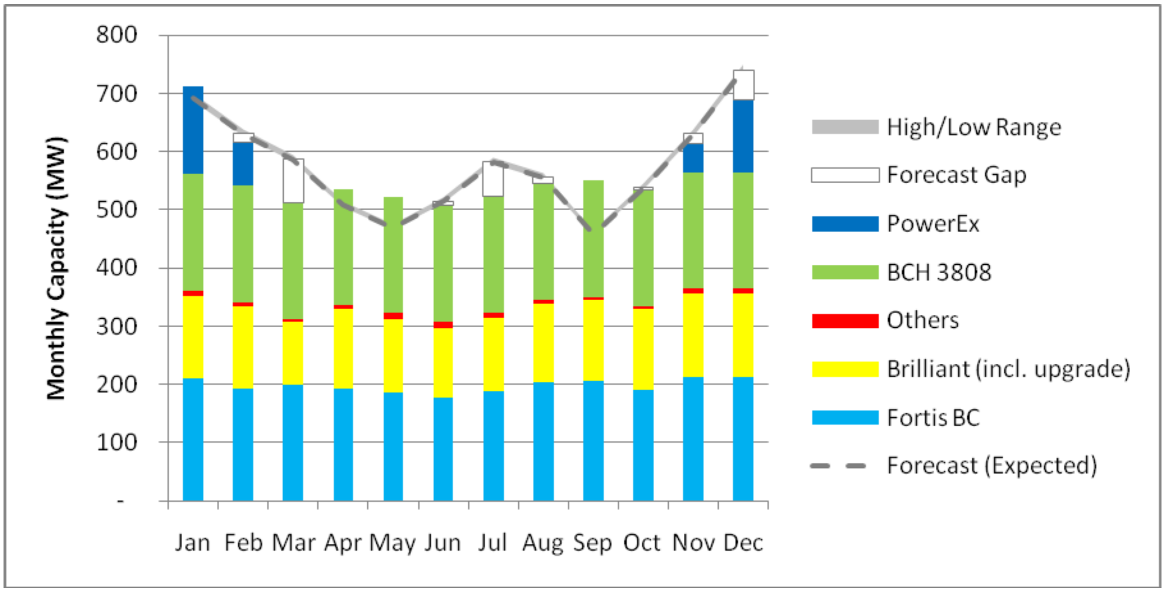
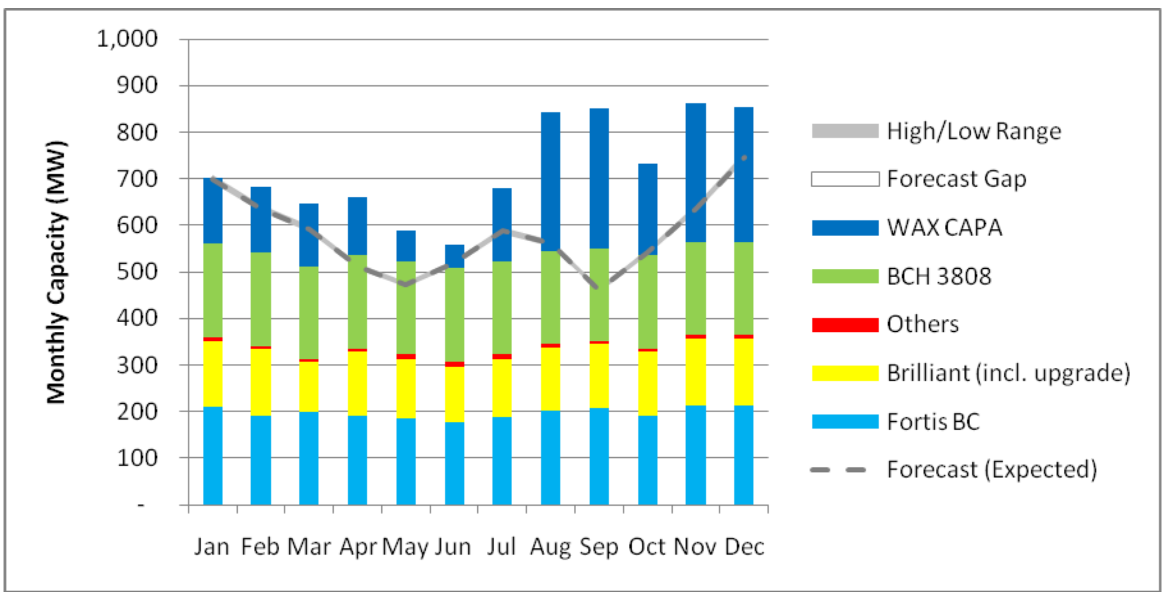


Figure BCOAPO IR1 45.1b - 2015 Monthly Capacity Load/Resource Balance



46.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, pages 17-18 and Appendix F

46.1 Please explain why Clean Energy Act Objective 2 (f) is not considered as applicable.

Response:

The Clean Energy Act objective 2(f) is "to ensure the ***authority's*** rates remain among the most competitive rates charged by public utilities in North America."

In the Clean Energy Act definitions, **"*authority*"** has the same meaning as in section 1 of the *Hydro and Power Authority Act*; which is the British Columbia Hydro and Power Authority.

Although the Clean Energy Act objective 2(f) is applicable to BC Hydro and not to FortisBC , the Company accepts that it has an obligation to its ratepayers to keep its own rates as competitive as possible.

46.2 With respect to Objective 2 (f) what does FortisBC see as its role in encouraging the use of electricity in lieu of more carbon intensive forms of energy?

Response:

FortisBC assumes that the question is intended to refer to Clean Energy Act objective 2(h) "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia". FortisBC sees objective 2(h) as a general provincial objective and as discussed below, the Company's role to serve this objective must must be as part of a coordinated effort between the province and energy industry participants or based on direction from government through regulations issued under the Clean Energy Act.

FortisBC believes that energy objective 2(h) is a general objective that speaks about energy switching in general and refers to energy use in all sectors and to migrating to lower emitting energy forms. FortisBC also believes that energy objective 2(h) has been set in place as a supplementary objective meant to support achieving the GHG emission reduction targets in energy objective 2(g). (Section 35(d) of the Clean Energy Act permits the Lieutenant Governor in Council (LGIC) to modify any objective except section 2(g) suggesting that achievement of the GHG emission reduction targets is the most important energy objective. The fact that the province has enacted several other pieces of legislation setting out the GHG emission reduction targets supports this view. If fuel switching to lower carbon fuels is done in an unplanned or uncoordinated fashion across energy forms and sectors there is significant potential for unnecessary costs to be incurred in the process of achieving other energy objectives such as reaching the GHG emission reduction targets.

For an electric utility in BC fuel switching from other energy sources to electricity has the potential to be a load building activity that may be at odds with energy objective 2(b) which deals with utilities taking demand side measures and conserving energy, or with the UCA requirements to pursue all cost effective demand-side measures. Electric load increases arising from fuel switching will require the addition of higher cost marginal supply resources to serve the new load. The high marginal cost of acquiring new electricity supply also means that it is difficult for electric fuel switching programs to pass the DSM economic hurdle. Fuel switching to electricity for some end uses such as for the thermal energy demands for space heating will add load disproportionately in the high demand winter period when electricity supply costs tend to be higher and when costly distribution system upgrades are more likely to be required to meet higher peak demand requirements. Using the right fuel for the right use as noted in the following quote from page 21 of the 2007 BC Energy Plan bears mentioning in the context of providing cost effective energy solutions for British Columbians that meet the province's energy objectives.

> *"It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province."*

FortisBC also notes that the LGIC may issue regulations pursuant to sections 18 and 35(n) of the Clean Energy Act that establish certain utility programs, projects, contracts or expenditures as "prescribed undertakings" for the purpose of reducing GHG emissions in BC. Prescribed undertakings under section 18 and 35(n) will promote the use of electricity or other clean or renewable energy forms rather than more GHG intensive energy sources. Once a prescribed undertaking has been established the Commission must allow a utility to recover its costs spent in delivering the prescribed project or program. Establishing prescribed undertakings under section 18 may be the main means by which the provincial government seeks to achieve energy objective 2(h). However, no such prescribed undertakings have been established for electricity as yet.

46.3 To what extent does the load forecast reflect the substitution of electricity for more carbon intensive forms of energy over the planning horizon?

Response:

Please see the response to BCUC IR1 Q46.2. The load forecast makes no direct adjustment for fuel substitution, however, any replacement of carbon intensive forms of energy with electricity would likely fall within the high and low bands of uncertainty presented in the load forecast. An exception to this may be a societal shift in fuel types, for example a large scale market penetration of true electric cars.

Although not directly incorporated in the load forecast, any shift in the use of electricity would be recognized through the change in customer use rates. Adjustments can then be made to future load forecasts.

47.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, page 32

47.1 Does FortisBC have any long-term transmission contracts that provide it access to markets outside of BC?

<u>Response:</u>

FortisBC has some rights to use Teck's 71 Line to access markets in the Pacific Northwest.

47.1.1 If yes, please outline what the current arrangements are (i.e., time frame, capacity and transmission paths involved).

<u>Response:</u>

Please see the response to BCOAPO IR 1.47.1.

47.1.2 Are these arrangements sufficient to support its anticipated reliance on market purchases for the period up to 2020 (per page 12)?

<u>Response:</u>

Yes.

47.2 As part of its 2012 Resource Plan, does FortisBC plan on acquiring additional longer term transmission capacity access to external markets? If not, why not?

<u>Response:</u>

No. As long as the Company has access to Teck's 71 Line, additional long-term firm transmission to access external markets is not needed. However, there may be specific market opportunities where acquiring additional firm transmission capacity makes economic sense, and these will be evaluated on a case by case basis as the opportunities arise.

48.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, pages 16-18 and 33

48.1 Please provide FortisBC's understanding as to whether the Clean Energy Act's requirement for "self-sufficiency" and the timing of 2016 are applicable just to BC Hydro or also applicable to FortisBC. In some places the text in the application refers to self-sufficiency as a "provincial goal" (page 16) while in others it is referred to as a BC Hydro obligation (page 33).

Response:

Section 2 of the *Clean Energy Act* sets forth British Columbia's energy objectives, which include "to achieve electricity self-sufficiency." Section 2(a) of the Clean Energy Act, which sets forth this objective, does not specify that it only applies to BC Hydro. However, specific provisions in the Clean Energy Act regarding "electricity self-sufficiency" are expressly applicable to BC Hydro. For example, section 3(1) of the *Clean Energy Act* requires that BC Hydro "submit to the minister, in accordance with subsection (6), an integrated resource plan that is consistent with good utility practice and that includes all of the following: (a) a description of the authority's forecasts, over a defined period, of its energy and capacity requirements to achieve electricity self-sufficiency; [and] (b) a description of the authority's forecasts, over a defined period, of its energy and capacity requirements to achieve electricity self-sufficiency…" Sections 6(2) provides that

> (2) The authority must achieve electricity self-sufficiency by holding,
>
> > (a) by the year 2016 and each year after that, the rights to an amount of electricity that meets the electricity supply obligations, and
> >
> > (b) by the year 2020 and each year after that, the rights to 3 000 gigawatt hours of energy, in addition to the amount of electricity referred to in paragraph (a), and the capacity required to integrate that energy
>
> solely from electricity generating facilities within the Province,
>
> > (c) assuming no more in each year than the heritage energy capability, and
> >
> > (d) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.

Additionally, section 8(1) also specifically applies to BC Hydro by stating:

> (1) In setting rates under the Utilities Commission Act for the authority, the commission must ensure that the rates allow the authority to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to
>
> > (a) the achievement of electricity self-sufficiency

Under the Clean Energy Act, British Columbia's energy objective to achieve self-sufficiency will be specifically applicable to FortisBC when it files its long-term resources plan under section 44.1 of the Utilities Commission Act as provided under section 6(4):

> A public utility, in planning in accordance with section 44.1 of the Utilities Commission Act for
>
> (a) the construction or extension of generation facilities, and
>
> (b) energy purchases,
>
> must consider British Columbia's energy objective to achieve electricity self-sufficiency.

Please also see FortisBC's definition of electricity self sufficiency provided in response to BCOAPO IR1 Q42.1.

49.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, page 34

49.1 Please outline the extent to which FortisBC and Alberta rely on the same markets for capacity and energy purchases.

Response:

FortisBC and Alberta can and do rely on the same markets for capacity and energy purchases, but they do not have equal access to the various markets. The difference in their access to the markets is linked to either economic factors (i.e. it will be less expensive to move power through fewer jurisdictions) or transmission constraints.

BC Market: The FortisBC system is well connected to the BC Hydro grid at multiple points of interconnection, and thus has relatively unconstrained access to electricity exchanges with BC Hydro (or its trading arm Powerex). Alberta has more constrained access to the BC Hydro system via a single congested intertie, which is frequently de-rated from its nominal capacity of 1200 MW to a practical operational limit of 500 - 700 MW (or less) for exports from BC to Alberta. With a peak load of approximately 10,000 MW, Alberta can supply at most 5-7% of its load requirement from the BC market

Alberta Market: FortisBC has more limited access to the Alberta Market than Alberta-based utilities have to their own market. The nominal Alberta/BC intertie rating for imports into BC is 1000 MW, although the available capacity rarely exceeds 500 MW in practice due to system constraints in Alberta. Given FortisBC's peak load of approximately 700 MW, a large percentage of FortisBC's requirements could theoretically be met with resources purchased and delivered from the Alberta Market, although it would be very costly for FortisBC to reserve the requisite firm transmission capacity, if it were even available, to ensure maximum access to the Alberta market during periods of low Alberta market prices.

Mid-Columbia Market: FortisBC and Alberta-based utilities can access the Mid-Columbia markets through the BC Hydro grid and the various US transmission grids. Alberta-based utilities would be required to move the electricity further than would be the case for FortisBC. Aside from transmission limitations between BC and Alberta described above, all parties would theoretically have equal access to Mid-Columbia market products.

However, through use of the 71 Line, which has 370 MW of Total Transmission Capacity, FortisBC has the added advantage of being directly connected to other Pacific Northwest markets without having to wheel through the BC Hydro system.

50.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, page 35

50.1 To what extent does the fact that WECC/NWPP relies on different drainage basins for its hydro-electric generation mean that low-flows in the basins serving BC are unlikely to have a wide-effect on WECC market prices.

Response:

There are numerous factors that impact market prices of electricity in the WECC, including, to name a few, weather driven demand, the price of natural gas, and the coincidence of low flows across various WECC watersheds. Nevertheless, all things being equal, less supply of electricity from BC Hydro generation will put upwards pressure on both NWPP and WECC market prices.

51.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, pages 38-39

51.1 Are the prices shown in Figures 3.3.2-A and 3.3.3-A in nominal $ (i.e., the price for 2020 is expressed in 2020 $)? If not, what is the basis for the prices shown?

Response:

The prices shown in Figures 3.3.2-A and 3.3.3-A are in nominal dollars.

52.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, page 52

52.1 Does the 50% apply to both energy and capacity growth?

Response:

FortisBC understands that the 50% target applies to energy. The 2007 BC Energy Plan states that "Current per household electricity consumption for BC Hydro customers is about 10,000 kWh per year. Achieving this conservation target will see electricity use per household decline to approximately 8,000 kWh per year by 2020."

52.2 Please explain what "DSM measures" are considered to be contributing to the FortisBC 50% target. For example, does it include the impact of "conservation rates" such as the RIB and TOU, DSM measures attributable to other parties (e.g. federal government energy efficiency programs) or information programs? Alternatively, does the load forecast prior to DSM measures presented in the Application (per pages 4 & 8) capture the impact of some of these initiatives?

Response:

The DSM measures and programs that contribute to meeting the 50 percent target are described in the 2012 long term DSM Plan, and the 2012-13 Capital Plan filing (section 7). Typically a DSM program consists of a tangible measure(s), for example. a compact fluorescent light, heat pump or efficient compressor.

The impact of conservation rates are not included as a DSM program measure (and therefore do not contribute to the 50 percent target), but are factored into the load forecast.

FortisBC does not explicitly incorporate the effect of third party DSM programs or legislation in to the load forecast prior to DSM. However, the effects of third-party DSM programs and legislation are incorporated to the extent that they have altered historical loads since the load forecast is partly based on historical loads.

53.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, page 62

53.1 Does the high/low range shown here only capture load forecast uncertainty as regard to the uptake of DSM (per page 52, lines 1-11 and page 53, lines 9-10) or does it also reflect the future load growth uncertainty discussed on page 52, lines 24-28?

Response:

The high/low load range simultaneously takes into account both uncertainties in DSM performance and load growths.

54.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, page 63

54.1 The Application states that higher than forecast demand, extreme weather events or individual transmission or generation contingencies could force FortisBC into the market for large volume purchases. Please confirm that the effect of these events are reflected in the PRM and, therefore, in the Capacity Gap as set out in Figure 5.2.1.3-D.

Response:

Yes, the PRM, as recommended by the WECC, captures the increased demand due to an extreme weather, unexpected load growth that exceeds generation additions, or contingency events such as a loss of up to one unit of generation. However, it is still possible to experience extreme events that exceed the PRM reserves held, such as the loss of two large generator units.

55.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, pages 68 and 84

FortisBC 2012 ISP – Volume 1 – 2012 Long Term Capital Plan, page 114

55.1 The Capital Plan cites instances (e.g. Section 2.8.10.3) where the addition of more local generation could offset the need for additional transmission/transformation investment. How have these opportunities been incorporated into FortisBC's Long Term Resource Plan?

Response:

As identified in Section 2.8.10.3 of the Long-Term Capital Plan, there may be opportunities where the addition of more local generation could offset the need for additional transmission/transformation investment. These opportunities have not been incorporated into the FortisBC Long-Term Resource Plan.

These opportunities will be considered when evaluating new generation options, and may become part of the justification for adding new generation resources within the FortisBC service territory.

56.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, page 79

56.1 The preceding sections noted that FortisBC's forecast energy and capacity gaps occurred in particular months and hours. Please comment on the extent to which each of the "new clean energy resources" identified would be available to meet the specific shortfalls when/as they occur.

Response:

The capacity and energy gaps to which this question refers are outlined in sections 5.2.1.2 through 5.2.2.3 (pg. 58 – 67) of Volume 2 of the 2012 Long Term Resource Plan (Exhibit B-1-2). Page 79 of the same document gives wind, run of river, and biomass as examples of new clean energy resources.

The capacity and energy availabilities of the new clean energy resources (Run of River, Wind and Biomass) are outlined in the 2010 Resource Options Report, attached as Appendix C to the 2012 Resource Plan (Exhibit B-1-2), and are summarized in the table below.

Table BCOAPO IR1 56.1

Resource	**Run of River Hydro (cluster of 9 within the FortisBC area); pg. 23 of 82**	
Resource type	Intermittent	
Capacity	10 MW dependable	(70 MW installed)
Annual Energy	205 GWh firm	(250 GWh average)
Resource	**Wind (within FortisBC area); pg. 41 of 82**	
Resource type	Intermittent	
Capacity	3 MW dependable	(30 MW installed)
Annual Energy	65.7 GWh average	
Resource	**Biomass (Woodwaste project bundle); pg. 45 of 82**	
Resource type	Base Load	
Capacity	15 MW dependable	
Annual Energy	145 GWh firm	(145 GWh average)

Energy gaps are reported on an annual basis. In other words, energy gaps are not associated with any given month or hour. Therefore the relevant time frame over which to evaluate the energy production of new clean energy resources is on an annual basis.

The energy available from the representative Run of River hydroelectric projects is 250 GWh per year. The Run of River hydroelectric projects assume an installed capacity of 70 MW and a net capacity factor of 41 percent. The annual energy production would be directly related to the projects' hydrology. (In a low water year, annual energy production would only be expected to reach 205 GWh, approximately 82 percent of the average annual expected generation.)

The annual energy availability from the representative 30 MW Wind project is 67.5 GWh, which equates to a net capacity factor of 25 percent. Similar to the Run of River hydroelectric projects, annual generation for wind projects will vary from year to year depending upon wind conditions.

The annual energy available from the representative 18.5 MW Biomass project is 145 GWh, which equates to a 90 percent capacity factor. However, unlike Run of River or Wind, Biomass fuel supply is within the control of the operator and therefore the annual energy should not vary dramatically from one year to the next.

It is worth noting that specific project energy shapes will be different than generic project energy shapes (e.g. annual averages). For example, Run of River hydroelectric projects have energy shapes that vary based on location, and FortisBC could contract coastal Run of River projects (outside its service area) to better match its demand. Coastal fall and winter rains provide more fall and winter energy and less freshet energy when compared to projects in FortisBC's service area.

Capacity gaps are reported on a monthly basis and are derived based upon the largest hourly gap in the given month.

Dependable Capacity is defined in the 2010 Resource Options Report (Appendix C in Volume 2 of the 2012 Long Term Resource Plan, page 4) as being the "generation available for three peak hours per day during the coldest two-week period each year. In BC, system peak electrical demand typically occurs in December or January sometime between the hours of 5 pm and 9 pm."

The dependable capacity for each of the new clean energy resources is:

- Run of River: 10 MW
- Wind: 3 MW
- Biomass: 15 MW

The dependable capacity for the above resources was originally derived primarily from information and data found in BC Hydro's 2008 Long Term Acquisition Plan (LTAP) and its 2006 Integrated Electricity Plan (IEP).

57.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, Appendix B, page 27 of 54

57.1 Please explain why the current SOP price offering of $101.36 is used as being representative of the current cost of new resources.

Response:

Section 5.2 (Exhibit B-1-2, Appendix B, pp. 26 of 54) provides the reasoning as to why Midgard believes that the current SOP price offering is representative of the current cost of new resources. The section reads as follows:

"At present, BC Hydro is operating a Standard Offer Program ("SOP") that presents IPP developers the opportunity to sign long-term contracts with BC Hydro whereby the IPP may sell their generation output to BC Hydro at a preset price. The SOP has recently been through a two-year review which produced a number of changes and updates. The eligibility requirements for the program include a 15MW maximum size limit, the need for generation to meet government defined clean or renewable qualification standards and for the generation to be located within British Columbia.

Unlike the recent BC Hydro Clean Power Call, the SOP does not discriminate between firm energy and non-firm energy. Consequently, after adjusting for month of delivery and time of day, all energy generated under an SOP contract receives the same preset price regardless of the certainty of production. Stated another way, BC Hydro assumes the intermittent and volumetric risk on the generation and therefore is in essence procuring an energy only product. As a result, the current BC Hydro SOP represents an accurate estimate of the cost of procuring a BC based energy only product (with the added benefit of being consistent with the prescriptions of the Clean Energy Act). Because of this, Midgard has estimated the forecast price curve for the BC New Resources

Market Energy based on the current SOP price offering which is $101.39/MWh in 2011 CAD. Therefore the 2011 price point for the Midgard British Columbia New Resources Market Energy curve is $101.39/MWh."

When BC Hydro performed its review and update of its SOP pricing, it selected a price that was sufficiently high to encourage IPP participation while low enough to ensure that only the most competitive projects would be viable (e.g. target of 500 GWh of new generation). Midgard believes that the work done by BC Hydro is fundamentally sound and appropriately represents the cost of new resources in BC.

57.1.1 Since it is a standard offer price, has Midgard assessed the market response to the current price and concluded that it is adequate to attract a material amount of energy in 2011?

Response:

Midgard has not yet assessed the market response to the recently revised Standard Offer Program energy price. The price was changed in January 2011, so it is relatively early to draw any conclusions regarding the adequacy of the current price to attract a material quantity of energy resources.

However, Midgard has provided FortisBC with the following comments on the process used to establish the revised Standing Offer Program price structure:

To establish the current Standing Offer Program price BC Hydro completed an analysis and review of the most recent Clean Power Call. The products requested in a Standard Offer Program (energy only product) are different than the Clean Power Call (energy plus capacity product), but the two are related as follows.

Firm energy prices during the most recent 2008 call ranged from $105.36 to $133.80. To begin constructing the Standing Offer Program price, BC Hydro selected a starting firm energy price of $117.76. This price was chosen for the following reasons:

- *The price was expected to attract a cumulative total of 500 GWh of energy per year.*
- *An energy cap was not required because the price selected was not at the top end of the marginal cost of generation curve, therefore providing a limit to the number of projects that would be successful.*
- *When analyzing the 2008 Clean Power Call results, a slight increase in price above $117.76 resulted in significantly more energy contracts, therefore this base price acts as a natural break point in the price curve.*

The Standing Offer Program does not compensate differently for firm and non-firm energy. The selected firm energy (energy plus capacity product) base price of $117.76 was modified in the following way to arrive at the Standing Offer Program base price (energy only product):

- *Monthly and seasonal adjusters built in to the Clean Power Call price were undone*
- *The firm energy price (energy plus capacity product) was converted to a non-firm energy price (energy only product) by assuming that 70% of delivered energy would be physically firm.*
- *The price was not levelized so that it reflected the nominal prices in the specified year and was escalated to reach the 2010 equivalent price per MWh.*

In addition to the above, various adders and losses were included for variables such as the Cost of Incremental Firm Transmission and Line Losses. This resulted in a base Standing Offer Program price for each major region of the province. Midgard subsequently took the average of these regional prices and escalated it (at 2.1% CPI) to convert it from 2010 to 2011 dollars.

Given the extensive analysis and rigorous review of the Standing Offer Program update by BC Hydro & the BCUC, Midgard believes that the average base price of $101.36 per MWh ($2011) has been prudently derived and has a reasonable chance of attracting a material quantity of energy resources.

57.1.2 Since it is a standard <u>offer</u> price, has Midgard assessed the market response to the current price in order to determine if the "price" is excessive and more than what is required to attract energy resources in 2011?

<u>Response:</u>

Please see answer to BCOAPO IR1 Q57.1.1. Although Midgard believes that the revised Standing Offer Program price has been reasonably derived it has not yet assessed the market response to the revised price.

57.2 Did Milgard undertake any independent assessment as to the reasonableness of using 50% of CPI as the escalation factor.

<u>Response:</u>

Midgard performed an independent assessment of the reasonableness of using a 50 percent CPI escalation. Midgard judged that using an escalation of 50 percent of CPI is reasonable because it is the contract price escalation factor built into the BC Hydro SOP price applicable to each PPA going forward from the point at which the PPA is signed and it has successfully attracted a number of SOP projects.

57.3 Given footnote #37, why wasn't a 100% of CPI escalator used?

<u>Response:</u>

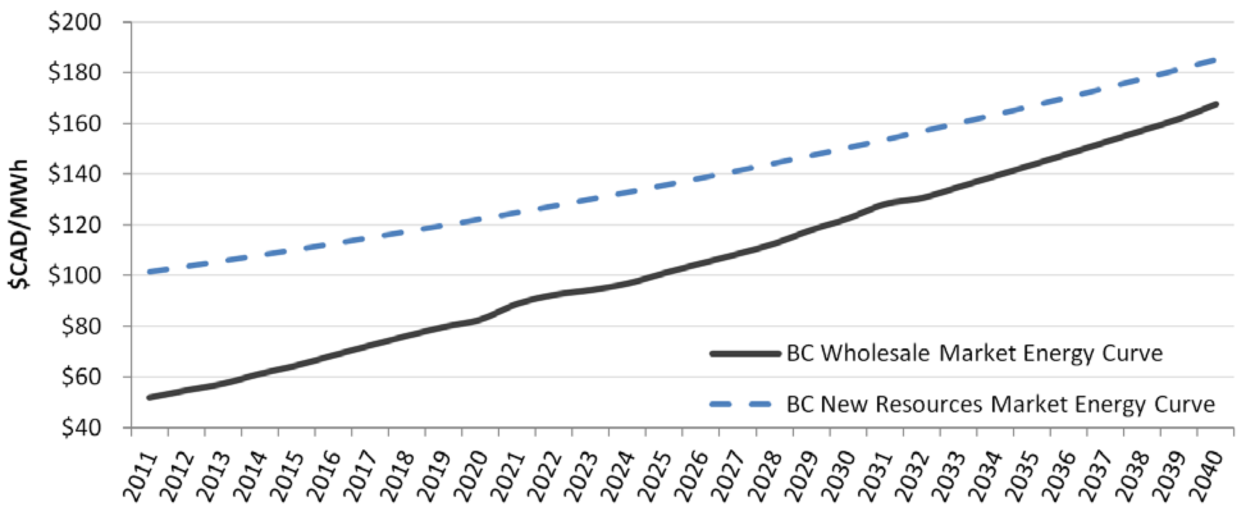
Please refer to the response to BCOAPO IR1 Q57.2.

57.4 Please re-do Figure 5.3-A using 100% of CPI as the escalator for BC New Resources.

Response:

A revision of Figure 5.3-A using 100% CPI for BC New Resources is provided as Figure BCOAPO IR1 57.4 below.

Figure BCOAPO IR1 57.4



The BC New Resources Market Energy Curve is based on the BC Hydro Standing Offer Program (SOP). Given that the embedded price escalation in a signed SOP contract is ½ CPI, FortisBC believes that the use of full CPI in this figure over-estimates the cost of new resources.

Please also refer to the response to BCOAPO IR1 Q57.2.

58.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, Appendix B, pages 29-31 of 54

58.1 Does the BC Wholesale Capacity Price Curve include any provision for firm transmission service for delivery to FortisBC? If yes, where and how is this included? If not, what adjustments are required to the price curve?

Response:

Yes, the BC Wholesale Capacity Price Curve does include provision for firm transmission service to the FortisBC service area, using the following formula:

FortisBC Price = [Mid-C Price + BPA Transmission Rate + BPA Losses] * [Foreign Exchange Rate]

BPA's transmission price was retrieved from its "2010 Transmission and Ancillary Service Rates" document; the "Day 6 and beyond" price of $0.046 /kW/day was chosen as an indicative price for planning purposes.

Losses were calculated as 1.9% of the Mid-C Price plus the BPA Transmission rate, as per the BPA Open Access Transmission Tariff (2010).

Foreign Exchange rate was calculated as decreasing linearly from current rates to 0.8 USD/CAD in 2040.

References:

2010 Transmission and Ancillary Service Rates

2010 BPA Open Access Transmission Tariff – Schedule 9, "Real Power Loss Calculation"

59.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, Appendix B, page 35 of 54

59.1 The discussion of market trends makes no mention of the likely impact of shale gas development on the supply and/or price of natural gas. Has this already been factored into the projected (electricity) Market Prices and, if not, what impact is it likely to have on the currently projected prices?

Response:

Please see the response to BCUC IR1 Q243.2.

60.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, page 1

60.1 The Application states (lines 21-22) that the 2012 DSM plan represents program savings only and excludes conservation effects induced by information or rate redesign. However, the Application then states (lines 23-25) that DSM programs include savings from an IHD. Since this is really just a form of customer information, please reconcile why this form of "information" is considered a DSM program while other forms are not.

<u>Response:</u>

The proposed IHD program is considered a DSM program since it will provide individual customers with a financial incentive to purchase a specific type of device with demonstrable energy savings.

61.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, pages 2-4

61.1 Please confirm that the *Clean Energy Act's* definition of a demand-side measure includes conservation effects induced by information or rate redesign (per page 2).

<u>Response:</u>

The Clean Energy Act and Utilities Commission Act both define a demand-side measure as a "rate, measure, action or program" that results in conservation. By this definition a rate design is considered a conservation "rate" and information is considered a conservation "program".

61.2 Please clarify whether the "before DSM Load Forecast" presented as part of the 2012 Long Term Resource Plan represents the demand for energy prior to any new demand side measures, including new rate redesign and customer information initiatives.

<u>Response:</u>

FortisBC clarifies that the "before DSM Load Forecast" represents the demand for energy before new demand side measures, including new rate design and customer information initiatives.

61.2.1 If not, please comment on FortisBC's compliance with Section 44.1(2) of the Act.

Response:

Please refer to the response to BCUC IR1 Q61.2.

62.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, pages 4-5

62.1 Please provide FortisBC's understanding of Section 4(3) of the DSM Regulation as it relates to the two following statement: as a bulk electricity purchaser is it required to:

- adopt BC Hydro's long-term marginal cost of electricity as its avoided cost of supply (as part 5 suggests), or
- when considering incremental acquisitions for BC Hydro, utilize BC Hydro's long term marginal cost of supply as the avoided cost (as opposed to the forecast cost of purchasing electricity from BC Hydro)?

Response:

Please refer to the response to BCUC IR1 Q296.1.

63.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, page 11

63.1 Please indicate how "free ridership" (i.e. the possibility some consumers will adopt a DSM measure without a program or incentive) is factored into the screening of various potential DSM-measures and what was the source of the free-ridership rates used.

Response:

Free-ridership rates were not factored into the screening of measures in the 2010 CDPR study.

64.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, page 13

64.1 Please provide the supporting calculations that show how the $84.94/MWh was determined from Table 5.1.3.3-A of the Midgard Report.

Response:

The $84.94 figure is the present value of the 30-year stream of expected mid-C prices (starting at $51.79 per MWh and ending at $167.50 per MWh), discounted at 8 percent.

64.2 Please clarify what year's dollar the $84.94 is quoted in and for what period it applies.

Response:

The $84.94 figure is in 2011 dollars and spans the 30-year period 2011-2040.

64.3 Please provide copies of the source BC Hydro documents used to derive the $154.15 / MWh avoided energy cost for BC Hydro.

Response:

The $154.15/MWh figures is the blended avoided cost used in the 2010 CDPR, and was incorrectly labeled as the BC Hydro avoided energy cost.

The 2011 BC Hydro avoided energy cost is based on escalating the $130/MWh price used in the BCH 2007 CPR[1], using a two per cent per annum escalation factor, to $143.53 in current (2011) dollars.

Table 3.2.1 should have used $143.53/MWh instead of $154.15/MWh as the input, which results in the following revised blended marginal cost:

[1] BC Hydro 2007 CONSERVATION POTENTIAL REVIEW – Summary Report –p.6. "Cost effective" for the purposes of this study means that the CCE is less than or equal to 13 cents per kilowatt-hour.(=$130/MWh),.

Table 3.2.1 (Revised) – Long-Term Avoided Power Purchase Costs

Component	Source	Long-term Avoided Cost	Proportion	Blended
Energy ($/MWh)	BC Hydro 2007 CPR	$143.53	28%	$101.34
	2011 Midgard market report	$84.94	72%	

Please refer to Errata 2.

64.4 If not set out precisely in the source documents please provide the derivation of the $154.15 value.

Response:

The $154.15/MWh figure used in the 2010 CDPR study was calculated as follows:

28% @ $140.78 + 72% @ $159.35 = $154.15 per MWh

Where $140.78 is the 2007 BC Hydro CPR $130/MWh price escalated to 2010 dollars, and $159.35 was the 2029 BC Market forecast price in 2010 dollars.

64.5 Please clarify what year's dollars the $154.15 is quoted in and for what period it applied.

Response:

That figure was derived in 2010 dollars, and applied to the period 2010-2029.

64.6 Please explain the basis for the 28%/72% weighting used for the two values.

Response:

The weighting is based on the proportion of FortisBC total energy requirements supplied by BC Hydro.

64.7 Why is the BC Hydro avoided cost included in the derivation of FortisBC's avoided cost when the Resource Plan does not call on increased use of purchases from BC Hydro to meet increased resource requirements?

Response:

This avoided cost calculation for BC Hydro purchases is in compliance with Section 4(3) of the DSM Regulation.

64.8 FortisBC's Long Term Resource Plan calls for continued reliance on market (not BC Hydro) purchases through to 2020 and the building of new resource options to meet supply shortfalls after that.

64.8.1 Why doesn't the cost of these resources form the basis for FortisBC's long run avoided cost of supply?

Response:

As outlined in the 2012 Long-Term Resource Plan, FortisBC proposes to continue relying on a Buy Strategy for purchasing energy and capacity resources before transitioning to a Build Strategy. No specific dates were set for new resource additions; those will be established as FortisBC continues to evaluate market conditions and opportunities in the future.

The long-run market price forecast represents FortisBC's best estimate of long-run marginal cost (also known as the "long-term marginal cost" or LRMC) of energy. Unlike BC Hydro, FortisBC does not have an energy call to base its calculation of LRMC from new resources. As mentioned above, specific dates for the acquisition of new resources (if any) are not certain. FortisBC has to do more evaluation on its preferred new resource options. Due to the uncertainty of the timing, type cost and approval of new generation resources, the determination of LRMC should be based on the forecast of the market price of power and not the cost of new construction.

Please see the response to BCUC IR1 Q242.1 for further discussion on FortisBC's LRMC.

64.8.2 What would be the levelized (30 year) avoided cost for FortisBC if it was calculated using the cost of these resource in the Short/Medium and Long Term? Please provide a response valued in the same year's dollars as the value reported in Table 3.2.1.

Response:

Please refer to the response to BCUC IR1 Q242.1.

65.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, page 13

65.1 The Application (line 22) suggests that incentive payments are included in the calculation of the TRC test. Please clarify. Is the intent of the statement to confirm that the total incremental cost of measure (whether paid by the consumer or by the utility via an incentive) is included as a cost?

Response:

Confirmed – the total incremental cost of the measure (whether paid by the customer or by the utility) is included as a cost in the TRC test.

65.2 Is the TRC test calculated using the costs and savings over the expected life of the measure, without any assumption regarding replacement at end of life? If not, how is "end of life" treated in the calculations?

Response:

Confirmed – there are no assumptions regarding the replacement at end of life of the measure.

66.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, pages 14-16

66.1 Please confirm that Table 3.2.3 sets out the targeted savings from programs implemented in the year noted.

Response:

Confirmed.

66.2 Please provide a schedule that sets out for each year (2011-2031) the savings from DSM programs initiated in that year and the savings that are assumed to continue from such programs in subsequent years. For example, the schedule would look somewhat as follows:

	Forecast Year					
Program Year	2011	2012	2013	2014	Through to	2031
2011	x	x	x	x	x	x
2012	-	x	x	x	x	x
2013	-	-	x	x	x	x
2014	-	-	-	x	x	x
Through to					x	x
2031	-	-	-	-	-	x
Total Savings	x	x	x	x	x	x

Response:

Please see Table BCOAPO IR1 66.2 below.

Table BCOAPO IR1 66.2

	forecast year																				
program year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
2011	31.6	31.6	31.6	31.6	31.6	29.9	29.9	29.9	29.9	24.5	22.6	22.6	22.6	22.6	22.6	20.7	20.7	17.2	17.2	9.2	-
2012	-	30.7	30.5	30.5	30.5	30.5	28.8	28.8	28.8	28.8	23.1	21.2	21.2	21.2	21.2	21.2	19.4	19.4	15.7	15.7	8.6
2013	-	-	31.8	31.4	31.4	31.4	31.4	29.7	29.7	29.7	29.7	23.5	21.5	21.5	21.5	21.5	21.5	19.7	19.7	16.4	16.4
2014	-	-	-	33.2	32.5	32.5	32.5	32.5	30.8	30.8	30.8	30.8	23.7	21.7	21.7	21.7	21.7	21.7	19.9	19.9	16.8
2015	-	-	-	-	34.8	33.8	33.8	33.8	33.8	32.1	32.1	32.1	32.1	24.0	22.1	22.1	22.1	22.1	22.1	20.2	20.2
2016	-	-	-	-	-	34.3	32.5	32.5	32.5	32.5	30.8	30.8	30.8	30.8	21.4	19.4	19.4	19.4	19.4	19.4	17.5
2017	-	-	-	-	-	-	28	27.4	27.4	27.4	27.4	26.0	26.0	26.0	26.0	20.0	18.4	18.4	18.4	18.4	18.4
2018	-	-	-	-	-	-	-	28.0	27.4	27.4	27.4	27.4	26.0	26.0	26.0	26.0	20.0	18.4	18.4	18.4	18.4
2019	-	-	-	-	-	-	-	-	28.0	27.4	27.4	27.4	27.4	26.0	26.0	26.0	26.0	20.0	18.4	18.4	18.4
2020	-	-	-	-	-	-	-	-	-	28.0	27.4	27.4	27.4	27.4	26.0	26.0	26.0	26.0	20.0	18.4	18.4
2021	-	-	-	-	-	-	-	-	-	-	28.0	27.4	27.4	27.4	27.4	26.0	26.0	26.0	26.0	20.0	18.4
2022	-	-	-	-	-	-	-	-	-	-	-	28.0	27.4	27.4	27.4	27.4	26.0	26.0	26.0	26.0	20.0
2023	-	-	-	-	-	-	-	-	-	-	-	-	28.0	27.4	27.4	27.4	27.4	26.0	26.0	26.0	26.0
2024	-	-	-	-	-	-	-	-	-	-	-	-	-	28.0	27.4	27.4	27.4	27.4	26.0	26.0	26.0
2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.0	27.4	27.4	27.4	27.4	26.0	26.0
2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.0	27.4	27.4	27.4	27.4	26.0
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.0	27.4	27.4	27.4	27.4
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.0	27.4	27.4	27.4
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.0	27.4	27.4
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.0	27.4
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.0
total savings	31.6	62.3	93.9	127	161	192	217	243	268	289	307	325	342	357	372	388	405	418	431	436	433

67.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, pages 16-17

FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, Appendix D, page 9

67.1 With respect to Appendix D, what portion of the total cumulative savings through to 2010 have been (or by the end of 2011 will have been) subjected to a formal M&E study to validate the assumed savings?

Response:

By the end of 2011, 94 percent of the total cumulative savings through to 2010 year-end will have been evaluated.

67.2 Based on the 2012-2014 M&E plan, what portion of the total anticipated cumulative savings reported up to the end of 2013 will have been subjected to a formal M&E study to validate the savings results?

Response:

By the end of the 2012-2014 M&E Plan 100 percent of cumulative savings reported from DSM programs will have been subjected to formal M&E studies.

68.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, page 13

FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, Appendix C, page 6

68.1 The first reference above states that $104.32/MWh was used to determine the benefits of DSM programs. However, the second reference states that $154/MWh was used. Please reconcile.

Response:

The first reference is to the blended avoided cost, of which 28 percent is prorated based on the $154/MWh, and was used in the 2012 Long Term DSM Plan and in the 2012-13 CEP Plan filing. The second reference was to the avoided cost used in the 2010 CDPR study to screen DSM measures. Although the two values are both derived in the same manner, they were calculated at different points in time (2009 in the case of the $154 figure and 2011 in the case of the $104.32 figure). The use of a different figure in the CDPR report (Appendix C) does not materially affect the rank order of the measures.

69.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, Appendix C, Tables 3 and 8 and Figure 27

69.1 Are the sector energy forecasts set out in the above references meant to be consistent with the Before DSM Load Forecast in the Long Term Resource Plan?

Response:

No, the sector energy forecasts incorporated into the 2010 CDPR are consistent with the 2009 Load Forecast. Appendix C was prepared in early 2010 for filing with the 2011 Capital Expenditure Plan.

69.2 Do these sector energy forecasts include the impacts of:

- Rate redesign (including TOU),
- Anticipated new codes and standards,
- Information programs
- Anticipated third party programs (e.g. the federal government)?

Response:

New rate designs were not included in the sector energy forecasts in the CDPR. The impacts of the last three items were not explicitly included, but may have been incorporated to the extent described in the response to BCOAPO IR1 Q52.2.

70.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, Appendix C, page 65

70.1 Why is there a zero value for the Total Measure cost for Consumer Electronics?

Response:

This is a presentation error in the table. The value should be $14,908. This is a presentation error only; the values are correct in the model calculations.

70.2 What is meant by the "Weighted" B/C Ratio?

Response:

Several measures are included in each of the categories in Table 19. The weighted B/C ratio is an average B/C ratio for the measures within each category. B/C ratios are weighted based on the technical kWh savings potential.

70.3 Is there a difference between the TRC test (with benefits expressed as a proportion of measure costs) and the Weighted B/C Ratio shown? If so, please explain.

Response:

The TRC ratio (with benefits expressed as a proportion of measure costs) is the same as the Weighted B/C Ratio.

70.4 Page 56 indicates that Clothes Dryers, Cooking, Dishwasher and Lighting LED do not pass the TRC test. What is the TRC ratio for each?

Response:

The TRC ratios are as follows:

Dishwasher – 0.85

Dryer – 0.26

Cooking – 0.28

Lighting LED – 0.29

70.5 Would any of these measures pass if considered Low Income initiatives and the 30% premium was included?

Response:

Yes, the Dishwasher measure listed in response to BCOAPO IR1 Q70.4 would pass if the 30 percent Low Income premium were included.

71.0 Reference: FortisBC 2012 ISP – Volume 2 – 2012 DSM Plan, Appendix C, pages 59 and 62

71.1 Page 62 states that no additional measures become cost-effective when low income benefits are added. Page 59 sets out the levels of insulation and window upgrade that are considered as economic. Please explain why the allowance of a 30% benefit premium for low income wouldn't permit higher levels of insulation/upgrade to be cost-effective in such circumstances.

Response:

Page 59 summarizes the cost-effective insulation and windows measures that were considered in the 2010 CDPR. It is possible that higher levels of insulation would be cost-effective (even without the added 30 percent), but the analysis did not include measures with higher insulation levels due to lack of verified savings and cost data.

Typically, higher-level insulation upgrades are limited due to diminishing returns (fewer energy savings for incremental insulation upgrades), structural limitations (not enough room in ceiling or walls for more insulation) or cost (wall re-siding required if insulating layer is added to exterior of existing walls).

FortisBC would evaluate any proposal for higher-level insulation upgrades on a case-by-case basis, and if the proposal was for the benefit of low-income customers, the cost-effectiveness test would include the 30 percent benefit premium.

72.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 1, page 3

72.1 Please explain the variance between the approved and actual rate base for 2011.

Response:

Provided in Table BCOAPO IR1 72.1 below is the variance between the approved and forecast rate base for 2011 with primary variance explanations.

Table BCOAPO IR1 72.1

	Rate Bae Parameters	Approved 2011	Forecast 2011	Variance 2011	Primary Variance Remarks
1	Plant in Service, January 1	1,417,415	1,403,617	(13,798)	Lower plant additions in 2010 by 4.9M, primarily in Distribution and General Plant. Higher retirements in 2010 by $8.9M, primarily due to OTR & 9 & 10 Line Retirements.
2	Net Additions	147,367	129,720	(17,647)	Lower plant additions in 2011 by 9M, primarily due to OTR Project. Higher forecast retirement in 2011 by $8.9M.
3	Plant in Service, December 31	**1,564,782**	**1,533,337**	**(31,446)**	
4	**Add:**				
5	CWIP not subject to AFUDC	5,444	6,237	793	
6	Plant Acquisition Adjustment	11,912	11,912	-	
7	Deferred and Preliminary Charges	24,984	19,408	(5,576)	Primarily relates to Flow through and ROE Sharing Mechanism of approximately $5M (Please refer Exhibit B-1, Tab-7, Page-10, Line-17).
8		**1,607,122**	**1,570,893**	**(36,229)**	
9	**Less:**				
10	Accumulated Depreciation				
11	and Amortization	375,482	352,464	(23,018)	Higher actual COR in 2010 ($3M) and higher forecast COR in 2011 ($2M). Higher actual Retirement 2010 ($8.9M) and higher forecast Retirement in 2011 ($8.9M). This results in a cumulative difference of approximately $23M.
12	Contributions in Aid of Construction	100,504	97,049	(3,455)	Customer driven: Lower Actual CIAC in 2010 followed by Lower CIAC Forecast in 2011
13		**475,986**	**449,513**	**(26,472)**	
14	Depreciated Rate Base	**1,131,136**	**1,121,380**	**(9,756)**	
15	Prior Year Depreciated Utility Rate Base	1,024,361	1,022,473	(1,888)	
16	Mean Depreciated Utility Rate Base	**1,077,748**	**1,071,926**	**(5,822)**	
17	**Add:**				
18	Allowance for Working Capital	5,599	7,361	1,762	
19	Adjustment for Capital Additions	9,894	(8,090)	(17,984)	Forecast implementation of some capital projects shifted from the beginning to the latter part of year 2011.
20	**Mid-Year Utility Rate Base**	**1,093,241**	**1,071,197**	**(22,044)**	

72.1.1 Please identify any capital projects that were planned for 2011 where the actual capital placed in-service varies from forecast by more than 10%.

Response:

The following capital projects planned for 2011 are forecast to vary from forecast costs by more than 10 percent:

Table BCOAPO IR1 72.1.1

	Additions to Plants in Service 2011	RRA Filing 2012-13 ($000s)	NSA 2011 As per RR 2011 ($000s)	Primary Variance ($000s)	Primary Variance %	Variance Remarks
1	**Transmission Plant**					
2	Okanagan Transmission Reinforcement	46,468	56,445	(9,977)	-18%	Cost savings achieved and $2M worth of schedule delays
3	Benvoulin Distribution Source	928	130	798	614%	Overbuilding of TELUS lines and weather related delays
4		**47,397**	**56,575**	**(9,179)**	**-16%**	
5	**Distribution Plant**					
6	New Connects System Wide	9,119	10,581	(1,462)	-14%	Lower customer activity
7	Distribution Sustaining	9,575	8,634	941	11%	Project cost carry over (primarily Passmore 19L) from 2010
8		**18,694**	**19,215**	**(521)**	**-3%**	
9	**General Plant**					
10	Distribution Station Automation	2,706	1,946	760	39%	The majority of this variance is a shift in timing of Plant in service from Dec.31, 2010 to 2011.
12	Mandatory Reliability Compliance	1,338	1,885	(547)	-29%	Plant in service shifted from 2011 to Dec.31, 2010
13	Vehicles	3,124	2,000	1,124	56%	Vehicles ordered in 2010 to be delivered in 2011
14		**7,168**	**5,831**	**1,338**	**23%**	
15	**Other Various Offsetting Projects**					
16	Other Various Offsetting Projects	**61,338**	**58,521**	**2,817**	**5%**	Various offsetting projects
19	**TOTAL**	**134,597**	**140,142**	**(5,545)**	**-4%**	

Note: Only variances beyond ± 10% and ± 500k have been considered.

72.1.2 Please identify those projects with under spending 2011 that will now carry over into 2012 and/or 2013.

Response:

As noted in response to BCOAPO IR1 Q72.1.1, the Okanagan Transmission Reinforcement project is forecasting approximately $2 million carry over into 2012.

FortisBC anticipates marginal carry over spending into 2012 from other projects within the 2011 capital plan to facilitate project close-out functions.

72.2 How much of the variance between the approved sales volume and the actual volume is due to variances from "weather normal" conditions?

Response:

As shown in Tab 1, page 3, Table 1.2 (Exhibit B-1), of the total variance between Forecast 2011 sales and Approved 2011 sales of 25 GWh, 18 GWh is due to weather.

72.3 Please confirm whether the actual "cost of equity" shown for 2010 and 2011 is the actual net income for the year.

Response:

The cost of equity amounting to $38.3 million, shown for 2010 in Tab 1, Pg 3, Table 1.2 of the 2012 – 13 RRA is the actual net earnings in 2010.

The cost of equity amounting to $45.9 million, shown for 2011 in Tab 1, Pg 3, Table 1.2 of the 2012 – 13 RRA is the forecast net earnings in 2011.

73.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 1, pages 5-6

73.1 Table 1.3-1 shows an absolute increase in energy sales to General Service for 2012 and again for 2013. However, Table 1.3-2 shows a decline in revenues at existing rates for each year relative to the previous year. Please reconcile.

Response:

The reduction in Commercial revenue in 2012 and 2013 is due to the rate rebalancing resulting from the Company's 2009 Rate Design and Cost of Service Analysis Application (Orders G-156-

10 and G-196-10). As illustrated below, almost all of the Commercial Rate Schedules will see a reduction in rates in 2011, 2012 and 2013.

Table BCOAPO IR1 73.1a

	2011	2012	2013	2014	2015
	Effective May 1	**Effective January 1**			
Small Commercial (GS20)	-5.5%	-2.0%	0.0%	0.0%	0.0%
Commercial (GS21)	-5.5%	-7.8%	-9.3%	-0.2%	-0.2%

The calculation for 2012 and 2013 Commercial Sales Revenue are presented below. Note that the revenue forecast is a combination of fixed and variable charges, therefore the change year over year is not simply a function of energy sales.

Table BCOAPO IR1 73.1b

SALES REVENUE CALCULATIONS		**2012**	**2013**
GENERAL SERVICE GS20		**Total**	**Total**
Accounts Billed/Customers		10,117	10,358
Consumption	*kWh to 16000 per 2 months*	**107,471,982**	**109,425,436**
	kWh to 200000 per 2 months	**85,579,541**	**87,135,070**
	kWh over	**5,970,666**	**6,079,191**
Account Fixed Charge	*Bi-monthly*	$ 31.92	$ 31.92
Unit Energy Charge - 0-16000	*$/kWh*	$ 0.08386	$ 0.08386
Unit Energy Charge - 16001-200000	*$/kWh*	$ 0.08386	$ 0.08386
Unit Energy Charge - Balance of kWh	*$/kWh*	$ 0.08386	$ 0.08386
Fixed Charge Revenue		$1,937,591	$1,983,726
Energy Charge Revenue		$16,690,001	$16,993,365
Total Revenue Estimate		**$18,627,592**	**$18,977,091**

Table BCOAPO IR1 73.1c

GENERAL SERVICE GS21		**Total**	**Total**
Accounts Billed/Customers		1,588	1,626
Consumption	*kWh to 8000 per month*	**114,370,401**	**116,449,245**
	kWh to 100000 per month	**293,384,943**	**298,717,628**
	kWh over	**89,507,271**	**91,134,192**
	kVA	1,029,644	1,063,217
Account Fixed Charge	*Monthly*	$ 15.01	$ 13.61
Unit Energy Charge - 0-8000	*$/kWh*	$ 0.07890	$ 0.07156
Unit Energy Charge - next 92000	*$/kWh*	$ 0.06550	$ 0.05941
Unit Energy Charge - Balance of kWh	*$/kWh*	$ 0.06550	$ 0.05941
Unit Demand Charge	*$/KVA*	$ 7.02	$ 6.37
Fixed Charge Revenue		$286,031	$265,558
Energy Charge Revenue		$34,103,265	$31,494,205
Demand Charge Revenue		$7,228,097	$6,772,695
Total Revenue Estimate		**$41,617,393**	**$38,532,458**
TOTAL GENERAL SERVICE		**$60,244,984**	**$57,509,549**

74.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 1, pages 8, 10 and 12

74.1 With respect to Table 1.7.1, what does the total labour inflation shown for 2012 and 2013 represent as a percentage of total labour costs for the respective preceding years that are subject to such inflation?

Response:

The 2012 Increase over the 2011 labour component is 3.8 percent.

The 2013 increase over the 2012 labour component is 2.2 percent.

74.2 With respect Figure 1.7.1, please provide a schedule that sets out for each year:

- The actual/forecast O&M costs,
- The actual/forecast customer count, and
- The inflation adjustment factor used.

Response:

The requested table is provided in Table BCOAPO IR1 74.1.a below. Table 74.2.b shows the calculation of O&M Expense per customer on in nominal and real dollar values.

Table BCOAPO IR1 74.2a

	2007A	2008A	2009A	2010A	2011F	2012F	2013F
O & M Costs	43,001	44,725	46,017	46,148	53,885	54,172	55,794
Year End Customer Count	107,724	109,719	110,853	112,250	114,336	116,105	118,357
Inflation Factor	101.7%	102.0%	102.1%	102.0%	102.3%	102.0%	102.0%
Cummulative Inflation Factor	101.7%	103.7%	105.9%	108.0%	110.5%	112.7%	115.0%

Table BCOAPO IR1 74.2b

	2007 A	2008 A	2009 A	2010 A	2011 F	2012 B	2013 B
Inflation Factor	101.7%	102.0%	102.1%	102.0%	102.3%	102.0%	102.0%
Cummulative Inflation Factor	101.7%	103.7%	105.9%	108.0%	110.5%	112.7%	115.0%
O&M Expense ($000)	43,001	44,725	46,017	46,148	53,885	54,172	55,794
Items not included in Cost							
Pension and Post retirement Benefits	(2,917)	(2,542)	(3,165)	(3,750)	(5,003)	(3,957)	(3,691)
Trail Office Lease	(600)	(753)	(1,212)	(1,212)	(1,212)	(1,212)	(909)
Mandatory Reliability Standards					(846)	(1,179)	(1,187)
2011 Sustaining Capital					(3,767)	(3,147)	(3,153)
Base O & M	**39,484**	**41,430**	**41,640**	**41,186**	**43,057**	**44,677**	**46,854**
Average number of Customers	105,069	108,722	110,286	111,552	113,293	115,221	117,231
Base O&M per Customer	**2007 A**	**2008 A**	**2009 A**	**2010 A**	**2011 F**	**2012 B**	**2013 B**
Nominal	**$ 375.80**	**$ 381.06**	**$ 377.56**	**$ 369.21**	**$ 380.05**	**$ 387.75**	**$ 399.67**
Inflation Adjusted	**$ 375.80**	**$ 367.31**	**$ 356.45**	**$ 341.73**	**$ 343.85**	**$ 343.94**	**$ 347.57**

75.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 2, page 8

75.1 Please confirm that the $0.2 M in ongoing costs is roughly equivalent to what is currently incurred and does not lead to a year over year increase in OM&A. If this is not the case, what is the year over year increase as result of having to support US GAAP as opposed to CGAAP?

Response:

Confirmed. The $0.2 million of ongoing costs is required under US GAAP beginning in 2012 and onwards. These forecast US GAAP ongoing costs have been included in the Finance operating expenses included in Section 4.3.4.15 of Tab 4 to this 2012-13 RRA. Since pre-changeover CGAAP has ceased to be a reporting option beginning in 2012, the only other option is IFRS. The $0.2 million of ongoing costs under US GAAP is approximately $0.1 million lower than the ongoing costs that would be incurred under IFRS beginning in 2012 and onwards. On July 7, 2011, the BCUC approved FortisBC to adopt US GAAP for regulatory purposes effective January 1, 2012, pursuant to Commission Order G-117-11.

76.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 2

76.1 Please provide a revised version of Table 4.1-1 that includes 2011 approved.

Response:

Please see the table below.

Table BCOAPO IR1 76.1

		Actual 2010	Approved 2011	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)				
1	Brilliant	33,216	32,282	32,267	35,601	36,785
2	BC Hydro	29,544	46,811	36,874	52,519	57,965
3	Independent Power Producers	914	168	153	155	158
4	Capacity Block Purchases	2,080	2,406	2,291	2,475	2,808
5	Market Purchases	8,222	856	4,211	214	545
6	Surplus Revenues	(1,000)	(670)	(259)	(284)	(267)
7	Capital Projects	(398)	(377)	(467)	-	-
8	Special and Accounting Adjustments	421	(750)	385	(750)	(750)
9	Balancing Pool	(1,036)	486	501	(156)	-
10	Planning Reserve Margin	-	-	-	-	311
11	Department Budget	-	-	-	1,211	1,266
12	**TOTAL**	71,964	81,212	75,956	90,984	98,821

77.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 6

77.1 What are the Base rates for Brilliant Energy Purchase for 2010-2011 excluding any true-up adjustment for prior years?

Response:

Please see the following table for a comparison of Brilliant energy base rates, with and without the true-up.

Table BCOAPO IR1 77.1

Brilliant Base Rates ($/MWh)			
Year	**Without Previous Year True-up**	**With Previous Year True-up**	**Difference**
2010	$ 36.68	$ 36.45	$ (0.23)
2011	$ 37.75	$ 35.31	$ (2.44)

77.2 What is the process by which the forecasts of annual operating and maintenance costs and capital charges (for both base and upgrades) are established for purposes of setting the rates? What recourse does FortisBC have if: a) it does not agree with the forecast or b) it does not consider the actual costs to have been prudently incurred?

Response:

The forecast of annual costs at the Brilliant Plant is a joint effort between FortisBC and the plant owner. FortisBC will bring forward the required work that needs to be performed and the plant owner will bring forward the required ownership costs. These items are then jointly reviewed and approved through the Brilliant Management Committee, which is composed of two members from FortisBC and two members from the plant owner. The Brilliant Management Committee will also review all actual expenses to ensure they were prudent.

78.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, pages 2 and 8

78.1 Please reconcile the BCH3808 percentage rate changes shown on page 8 with the statement on page 2 that rate increases of 8% per annum were assumed.

Response:

Please refer to the response to BCUC IR1 Q11.1.

79.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, pages 10-12

FortisBC 2012 ISP – Volume 2 – 2012 Long Term Resource Plan, Appendix B, pages 22-24 of 54

79.1 The first reference states that a cost of $4/MWh US is applied to the forecast Mid-C price as transmission charge. The second reference employs a transmission charge of $1.917/MWh. Please reconcile.

Response:

The $4.00/MWh is a FortisBC estimate used for potential market purchases in 2012 and 2013. The $1.917/MWh is a Midgard estimated used to derive a long range forecast of wholesale market prices.

Midgard derives its estimate of transmission charges of $1.917/MWh based on an estimate of the middle ground between the long-term rate of $1.298/KW/month ($1.778/MWh) and the day to day rate of $0.06/KW/month ($2.50/MWh).

FortisBC uses the estimate of the hourly non-firm point to point wheeling rate.

79.2 Please provide a schedule that compares the mid-C prices in HLH for 2011-2013 as set out in both references. Which forecast does FortisBC consider to be more current and reliable?

Response:

FortisBC considers its forecast to be more current and reliable for the test period (2012 and 2013) since it is based on actual forward prices that were currently available in the market at the time of filing. The Midgard analysis is a fundamentals-based approach to market price forecasting and is more reliable as a long term forecast. Please see Table BCOAPO IR1 79.2 below.

Table BCOAPO IR1 79.2

Year	Heavy Load Energy Market Price ($/MWh)	
	Midgard "Energy and Capacity Market Assessment" Table 5.1.3.3-A	FortisBC Forecast
2011	$54.24	$39.68
2012	$57.27	$51.79
2013	$60.01	$60.42

80.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, pages 23-24

80.1 Please provide a schedule that identifies those sources of variance that will be fully captured in the proposed Power Purchase Expense Variance Deferral and Revenue Variance Deferral Accounts for which there is currently either a) no true-up provided or b) a 50% true-up is currently provided.

Response:

In 2012, all variances in the proposed Power Purchase Expense and Revenue will be captured in the deferral accounts. In 2011, variances are treated in the following manner.

Power Purchase Expense Variances:

BC Hydro	100% true-up of rate variances, 50% of volume variances by way of PBR sharing mechanism
Brilliant	100% true-up of rate and volume variances
IPPs	50% of true-up of rate and volume variances, by way of PBR sharing mechanism
Market	50% true-up of rate and volume variances, by way of PBR sharing mechanism
Surplus Sales	50% true-up of rate and volume variances, by way of PBR sharing mechanism
FortisBC Entitlement	100% true-up of rate variances (balancing pool adjustments are valued at the BC Hydro rate); 50% of volume variances, by way of PBR sharing mechanism
Management Expense	50% true-up of Power Purchase Management Expense variance, by way of PBR sharing mechanism.

Revenue Variances:

50% true-up of volume variances, by way of PBR sharing mechanism (although at the aggregate level, the average energy rate varies because of customer class sales mix differences, unit rate variances are nil, once rates are fixed for the test year).

80.2 Does the introduction of this Variance Deferral Accounts reduce FortisBC's business risk? If not, please explain.

Response:

No, the deferral accounts do not reduce the business risk to FortisBC. They would however reduce the revenue and expense volatility in the short term and avoid windfall gains and losses.

The Utilities Commission Act ensures that prudently incurred costs are recoverable by the utility (section 59(5)(b)), and allows for the filing of new rate schedules if necessary for the recovery of prices over which the utility has no effective control (section 61(4)).

The business risk to a utility is the risk of its ability to recover the capital investments it has made to serve customers over the long term, and to receive a fair and appropriate return on its investment. Deferral accounts are short-term mechanisms that do not affect the Company's long term business risk.

80.3 Please explain why the balance in the Power Purchase Account is to be disposed of over one year whereas three years is proposed for the Revenue Account. Why shouldn't the periods be the same for both?

Response:

FortisBC has proposed a three year amortization period for the Revenue Deferral Account in order to address the effect of load variances on revenue requirements. Load variances are expected annually, primarily due to weather-related factors, and a multi-year amortization period provides a smoothing mechanism that could reduce the magnitude of the flow through. Power Purchase Expense variance, in addition to load variances, also includes rate forecast variances, and the Company has suggested that the Power Purchase Expense variance be amortized annually beginning in 2014. The variation in weather is expected to somewhat normalize out the variances in Revenues over time; whereas Power Purchase variances, which are primarily rate driven, are not expected to normalize out over time.

Since the Company does not propose further adjustments to 2013 rates following the disposition of the 2012-13 RRA, the amortization period for the Power Purchase Expense and Revenue Deferral Accounts will not be approved until the 2014 RRA. FortisBC is open to discussing amortization periods for these accounts different from those suggested in this filing.

81.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 26

81.1 Is the difference between forecast and actual Wheeling Expense also subject to Variance Deferral Account Treatment? If not, why not?

Response:

FortisBC has not proposed including variances in Wheeling Expense in the Power Purchase Expense Deferral Account. Wheeling expense primarily includes wheeling services under the Company's General Wheeling Agreement (GWA) with BC Hydro in addition to smaller amounts under BC Hydro's Open Access Transmission Tariff (OATT) and the use of Teck's 71 Line. As

GWA nominations are made five years in advance, volume variances can result from OATT or 71 Line wheeling. Rate variances may result from forecast differences in escalation factors.

The Company would not object to including Wheeling Expense in the proposed Deferral Account. Variances from 2007 to 2011 forecast are shown in the following table.

Table BCOAPO IR1 81.1 - Wheeling Expense Variances 2007 – 2011

	2007	2008	2009	2010	2011F	Total
			Over/(Under) Approved			
Forecast	3,466	3,622	4,010	4,019	4,138	
Actual	3,471	3,655	4,003	4,050	4,243	
Difference	5	33	(7)	31	105	167

82.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab page 28

82.1 Is the difference between the forecast and actual Water Fees also subject to Variance Deferral Account Treatment? If not, why not?

Response:

Please see the response to BCUC IR1 Q22.1.

83.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 34

83.1 Please revise Table 4.3.2.1 to include the Executive employee group.

Response:

The Executive is included in the Exempt group in Table 4.3.2.1 (Exhibit B-1).

83.2 Please indicate the proportion of employees that fall into each category (i.e., COPE, IBEW, Exempt and Executive) based on 2010 actual employee count.

Response:

Please see the Table BCOAPO IR1 83.2 below.

Table BCOAPO IR1 83.2

Affiliation	Proportion
Executive	2%
Exempt	25%
COPE	28%
IBEW	45%
TOTAL	**100%**

84.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 45

84.1 Are the labour expenses shown in Table 4.3.4 those associated with the FTEs also reported in the Table?

Response:

The FTEs reported in the table are total FTEs for the Company. When employees work on jobs or projects that are not Operating and Maintenance related, the cost for that work is charged directly to the other job or project (or in some cases to overhead loading accounts) and not to Operating and Maintenance. The total FTE count is presented before charge-outs. Changes in the labour expense will not directly match changes in the FTE count because only the Operating and Maintenance labour expenses are captured in the table.

85.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 48

85.1 Please explain why the labour expenses increase by almost 15% between 2011F and 2013F when the number of FTEs is unchanged.

Response:

Table 4.3.4.1, Tab 4, pp. 48 incorrectly included certain overhead costs within the labour costs for 2011, 2012 and 2013. Please refer to Errata 2 for a revised Table 4.3.4.1. As shown in the corrected table, the increase in labour expenses from 2011F to 2013F is approximately 23 percent.

The FTEs reported in the table are total FTEs for the generation business unit. When employees work on jobs or projects that are not Operating and Maintenance related, the cost for that work is charged directly to the other job or project (or in some cases to overhead loading accounts) and not to Operating and Maintenance. Generation is able to maintain the same number of FTE's by allocating resources as required between capital, third party and operating work. Changes in the labour expense will not directly match changes in the FTE count because only the Operating and Maintenance labour expenses are captured in the table.

85.2 Please explain why labour expenses increase by 23% between 2010A and 2011F when the FTEs increase by roughly 1%.

Response:

Labour expense in the schedule on Tab 4 page 48 incorrectly included some non labour overheads. The labour expense in the 2011 forecast is actually $81,000 less than 2010 actual. These values are correctly stated in Errata 2.

86.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 52

86.1 Please identify separately the costs included in each year's O&M for the three items listed at lines 9-11 and break down as between Labour and Non-Labour.

Response:

Please refer to the response to BCUC IR1 Q42.1.

86.2 Please explain the basis for the general decline in FTE's as between 2007A and 2010A. Why is this decline forecasted to reverse?

Response:

Please refer to the response to BCUC IR1 Q41.1.

87.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 56

87.1 What is the process by which the forecasts of annual operating expenses and the capital charge for the BTS are established for purposes of setting the rates? What recourse does FortisBC have if: a) it does not agree with the forecast or b) it does not consider the actual costs to have been prudently incurred/appropriately calculated?

Response:

The forecast for the annual operating and capital charges are provided by the Brilliant Power Corporation and are approved by the BTS management committee each year. The BTS Management Committee is comprised of representatives from Columbia Power Corporation and FortisBC. The capital charge is based on amortization schedules established when construction was completed. The capital charges are therefore predictable in any given year.

The most significant operating costs are Provincial Property taxes and O&M expense.

At the end of each year, the actual expenditures incurred are compared to the original estimate. Any variance between actual expenditures and the original estimate is added to or subtracted from the values to be included in rates in the next year.

The Brilliant Terminal Station Facilities Interconnection and Investment Agreement provides for dispute resolution. If disputes do arise, the circumstances are referred to the BTS Management Committee for resolution. If the BTS Management Committee is unable is unable to resolve the dispute, it is referred to an independent arbitrator.

88.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 58

88.1 Is the cost of external contractors reported under Labour or non-Labour expenses?

Response:

The cost of external contractors is reported under Non-Labour expenses.

89.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 60

89.1 With the forecasted return to full complement in 2011F why aren't non Labour costs reduced closer to 2008A levels?

Response:

2011 Non-Labour costs are in line the normal levels of approximately $0.4 million similar to 2007, 2009, 2012 and 2013. 2008 non labour costs were approximately $0.3 million which is lower than normal levels due primarily to savings in legal and consulting expenses resulting from lower than normal legal and regulatory activities during the year. 2010 was the only year since 2007 that non labour costs were higher than normal ($0.6 million) due to back filling a vacancy with a full time consultant as described in Tab 4 page 60 of the Application.

90.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 62

90.1 Do the FTEs shown in Table 4.3.4.8 include those associated with the DSM program and the AMI project? Please re-do the table excluding these initiatives.

Response:

Please refer to Table BCOAPO IR1 Q90.1 below

Table BCOAPO IR1 Q90.1

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents excluding DSM and AMI**	53	52	55	56	56	56	55
2.0	**Expenses**							
2.1	Labour	4,184	4,046	4,152	4,329	4,611	4,783	4,830
2.2	Non Labour	1,970	2,226	1,683	1,646	1,801	1,954	1,976
TOTAL O&M EXPENDITURE		6,154	6,272	5,835	5,975	6,412	6,737	6,806

The labour costs related to AMI and DSM are recorded in deferred accounts.

90.2 Apart from DSM and AMI, are any of the Customer Service costs charged to capital projects (and thereby contributing to year to year variations)?

<u>Response:</u>

Yes, apart from DSM and AMI, other Customer Service expenses are charged to capital projects. Examples include costs related to new service installations and costs for support for specific FortisBC capital projects.

91.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 66

91.1 What is the annual impact of the Community Investment Program on the O&M costs reported for 2010-2013?

<u>Response:</u>

The following percentages impacts of the Community Investment Program are based on the total operating budget for the Community and Aboriginal Affairs department.

- 2010 – 35%
- 2011 – 33.6%
- 2012 – 29.6%
- 2013 – 29%

92.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 67

92.1 Are the DSM program communication costs included in the cost summary shown?

<u>Response:</u>

The DSM program communications costs are not included in the cost summary shown. DSM communications costs are included in the DSM Deferred Charge Account.

92.1.1 If yes, why aren't these costs charged to the DSM program and accounted for the same as other DSM programming costs (i.e., deferred and amortized)?

Response:

Please see the response to BOAPO IR1 Q92.1.

93.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 78

93.1 Please explain the increase in non Labour costs as between 2010A and 2011F.

Response:

Additional costs are forecast in the Non-Labour area for safety system studies, and audits.

94.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 84

94.1 Please explain the over 17% increase in Labour cost for 2011F when FTEs increase by only 6%.

Response:

The Increase in labour costs between 2010A and 2011F is primarily due to the following:

1) Increases in employee future benefit costs;
2) Inflation of labour costs;
3) Reorganization of one position that had been shared 50% with another department became 100% in Finance; and
4) Labour costs associated with one FTE, which was previously charged out to a project as part of the transition to IFRS (International Financial Reporting Standards) in 2010A, have been reallocated to the Finance and Accounting operating and maintenance expenses for 2011 due to ongoing accounting requirements and the termination of the transition to IFRS at the end of 2010.

95.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 89

95.1 Please explain the 8.5% increase in Labour costs from 2010A to 2012F when FTE's are declining by over 7%.

Response:

The increase in labour expense is due to two factors. The labour expense shown in the table is net of direct charges to capital. The increase in labour costs is due to an expected reduction in charges to capital in 2012 and 2013 by approximately $0.2 million and wage escalation of approximately $0.1 million over the two years that offset the reduction in FTEs.

96.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 98

96.1 Please expand Table 4.3.4.18-5 to include the years 2009A-2011F. For each year, please also indicate the proportion of Fortis Inc's total corporate costs that are allocated to FortisBC Inc.

Response:

Please see the following table.

Table BCOAPO IR1 96.1 – Fortis Inc. Cost Allocation to FortisBC

	2009A	2010A	2011F	2012F	2013F
FortisBC Allocation Percentage	**12.74%**	**12.79%**	**13.20%**	**13.16%**	**13.16%**
Executive Function	$391	$505	$581	$579	$614
Treasury Function	65	51	64	65	68
Investor Relations Function	204	187	199	209	219
Financial Reporting Function	172	205	216	238	236
Internal Audit Function	17	19	21	21	22
Board of Directors	258	279	224	234	246
Other	297	414	387	389	377
Subtotal	1,404	1,659	1,692	1,735	1,782
Less: Fortis Properties Management Fee Revenue	(191)	(192)	(198)	(197)	(197)
Less: Net Pole Revenue allocable to FBC	(294)	(184)	0	0	0
Total	$919	$1,283	$1,494	$1,538	$1,585

Please also refer to the response provide to BCUC IR1 Q62.22.

96.2 What oversight role/governance does the Board of Directors for Fortis Inc. provide to FortisBC that is not provided by its own Board of Directors?

Response:

Fortis Inc. (FI) is a diversified, international distribution utility holding company having investments in distribution, transmission and generation utilities, as well as commercial real estate and hotel operations, and is listed on the Toronto Stock Exchange. The key services performed by FI are strategic and corporate governance in nature providing access to equity capital markets and providing a market return to its shareholders. FI's business focus is therefore different from that of FortisBC's in its capacity as a regulated integrated electric utility.

Therefore, although the fundamental activities of oversight and governance are described in the same general terms, as set out in lines 5 – 9, Tab 4, Page 95 for FortisBC and 14 – 19, Tab 4, Page 97 of the Application for FI, the actual role of the FI Board of Directors would be focused on activities as they relate to ensuring FI's access to equity capital markets and providing a market return to its shareholders. In addition the FI Board provides shareholder oversight to the strategic plans developed by FortisBC following approval by the FortisBC Board. The FI Board activities would be complementary and extend beyond those of the FortisBC's Board of Directors with its focus on activities associated with FortisBC's delivering safe, reliable energy to our customers and meeting the requirements of external regulators and other stakeholders.

96.3 For each of the following Fortis Inc. functions please indicate the services provided to FortisBC that are not provided by FortisBC's own staff/operations:

- Executive Function
- Investor Relations
- Financial Reporting

Response:

Executive Function

The key services performed by the FI Executive are strategic and corporate governance in nature and provide access to equity capital markets and a market return to its shareholders. FI's Executive focus is therefore complementary to but different from that of FortisBC's Executive focus on activities associated with FortisBC's delivering safe, reliable energy to its customers and meeting the requirements of external regulators and other stakeholders.

Investor Relations

FortisBC is a wholly owned subsidiary of FI and is not listed on any stock exchanges and therefore does not have an Investor Relations function. All investor relations are provided by FI.

Financial Reporting

The FI Financial Reporting function prepares monthly, quarterly and annual financial statements, the Annual Information Form, quarterly and annual Management Discussion and analysis and other continuous disclosure documents as required for FI in order to provide access to equity capital markets to provide equity to its subsidiaries including FortisBC.

FortisBC Financial Reporting prepares monthly, quarterly and annual financial statements, the Annual Information Form, quarterly and annual Management Discussion and analysis and other continuous disclosure documents as required for FortisBC as a venture issuer in order to provide access debt markets. FI Financial Reporting is not provided by FortisBC's own staff or operations except to the extent FortisBC's financial information is consolidated at the FI level.

Please also see the response to BCUC IR1 Q96.2.

97.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 103

97.1 Why was 2010 chosen as the "study year" when the forecast capital spending for that year was significantly higher than historical or forecast average spending?

Response:

2010 was chosen because it was the most recent year in which the Company had actual results on which to base the analysis.

97.2 Was any comparable analysis done using other years? If yes, please provide the results.

Response:

No, the Company did not complete any comparable analysis using other years.

98.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, page 109

98.1 Does FortisBC receive any apprenticeship or training tax credits?

Response:

Yes, FortisBC is eligible for both the BC Training Tax Credit and the Federal Apprenticeship Job Creation Tax Credit. Because these credits generally do not have a significant impact on income tax expense, as well as the difficulty in determining what level of training requirement has been met until the end of the year, these tax credits have not been included in the calculation of forecast 2011, 2012 or 2013 Income Tax Expense.

98.1.1 If not, why not?

Response:

Please see the response to BCOAPO IR Q98.1.

98.1.2 If yes, where are they accounted for in Table 4.6.2?

Response:

Yes, the Company is eligible to receive such credits, depending on whether certain criteria have been met by the end of the taxation year. For 2010 actual, these tax credits have been taken on Table 4.6.2 Income Tax, of line 21 labeled "Investment Tax Credit". These credits have not been included in the forecast for 2011, 2012 and 2013 income tax expense which would otherwise be shown on line 21 in Table 4.6.2 on page 109 as they are generally not known until the end of the year.

Please see the response to BCOAPO IR Q98.1 which discusses the difficulty in forecasting these tax credits and that they do not generally have a significant impact on the income tax expense calculation.

99.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, pages 116-117

99.1 Do the $0.1 M and $0.2 M reductions in expense apply just to O&M costs or do the reductions also include savings in capital spending?

Response:

The reductions of $0.1 million in 2010 and $0.2 million in 2011 represent O&M savings.

99.2 What is the estimated impact for 2012 and 2013 on a) O&M expenses and b) capital spending of the GST and PST harmonization?

Response:

The O&M expenses and capital expenditures for 2012 and 2013 have been forecast based on the implementation of HST effective July 1, 2010. The Company does not maintain two sets of books to track the variance between the O&M expenses and capital relating to the HST rules effective July 1, 2010 and the O&M expenses and capital relating to the old PST rules prior to July 1, 2010.

On Friday, August 26, 2011, as a result of a public referendum, the BC government announced that it will extinguish the federally administered HST system and reinstate PST with a current target date set for April 2013. Due to the complexities and current uncertainties around the unwinding of HST and reinstatement of the PST, the Company is not able to forecast the dollar value impact on O&M expenses and capital spending at this time.

99.3 What would be impact on O&M and capital spending expense for 2012 and 2013 if the PST was reduced as described at page 116, lines 29-32?

Response:

As the referendum results did not support retaining the HST, the two percent reduction in the tax rate will not occur.

99.4 If the HST is retained and the PST reductions are implemented will the HST Removal or Reform Deferral Account track the savings for future refund to consumers?

Response:

On Friday, August 26, 2011, as a result of a public referendum the BC government announced that it will extinguish the federally administered HST system and reinstate PST with a current target date set for April 2013. Due to the complexities and current uncertainties around the unwinding of HST and reinstatement of the PST, the Company is not able to forecast the dollar amounts that could potentially be captured in the HST Removal or Reform Deferral Account at this time.

If the HST was retained, the provincial component of the HST was expected to be reduced. PST, which is a non-recoverable tax, would have continued to remain obsolete if the HST was retained as proposed. Since HST is primarily a recoverable flow through of taxes, unlike the old PST, the O&M and capital spending was not expected to be impacted by a decrease in the HST rate. The exception would have relate to any capital costs or expenses incurred that are required to adjust the Company's systems for the rate change which could potentially be captured in the requested variance deferral account.

100.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, pages 119 and 122

100.1 What was the term for each of the long term debt series listed in Table 4.7.1-1?

Response:

Please see the response to BCUC IR Q81.3 for details on the term of each long-term debt series.

100.2 On what basis has FortisBC decided that a 30-year term is appropriate for the 2013 debt issue?

Response:

Please see the response to BCUC IR Q83.6.

101.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 4, pages 127-128

101.1 Has TGI completed its study of alternative formulae to an automatic adjustment mechanism as directed by the BCUC in G-158-09? If yes, please provide.

Response:

Yes, the study has been completed, filed with the Commission on December 8, 2010, and is provided as BCOAPO IR1 Appendix 101.1.

The study examined all North American jurisdictions where formulas had been used directly or indirectly to set allowed returns and internationally where information was available.

In its conclusions,

> *"The Terasen Utilities have not found a formula in Canada or the U.S. that ensures fair and reasonable returns over time, and that meets the fair return standard, although a couple of those identified in the Concentric report came somewhat close to the BCUC's 2009 Decision in a backcast analysis."*

The report went on to say:

> *"The Terasen Utilities believe that the same criteria would be necessary to underpin an AAM if an AAM formula were to be introduced in the future. Further, should an AAM be implemented it is critical that the starting point be set at a level that meets the fair return standard. Given this requirement, the recency of the Decision in late 2009 and the gradual economic recovery, the Terasen Utilities are not proposing that the Commission adopt a formulaic AAM at this time."*

102.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 5, page 16

102.1 Is there a materiality limit associated with the "costs" that would be subject to consideration for inclusion in the Extraordinary Costs (Z-Factor) Variance Deferral Account?

Response:

FortisBC has not proposed a materiality limit associated with costs to be included in the Extraordinary Costs (Z-Factor) Variance Deferral Account. Any balance in the account would be subject to examination and approval in the next Revenue Requirements application before being recovered or refunded through rates.

103.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 5, pages 19 and 21

103.1 With respect to items (v), (vi) and (xvi), why is FortisBC proposing to dispose of the deferral account balances prior to knowing what the "actual" costs are?

Response:

FortisBC proposes an amortization period of five years (2012 – 2016) of the ISP and 2012-13 RRA (item xvi), which is the period of time over which the benefits will be realized (that is, before the expected submission of new long term strategic plans). In the alternative, since the Company does not expect a subsequent adjustment to approved rates for 2013, amortization of this account would begin in 2014. This would potentially result in simultaneous amortization of the current and next long term plans. The Company expects that, following amortization of the forecast $0.476 million in each of 2012 and 2013, the remaining balance in the deferral account would be amortized in equal parts over the next three years.

Forecast costs of items v and vi, the RIB and Industrial Stepped Block Rate Applications and the Irrigation Consultation and Load Research projects are proposed to be amortized in 2012 and 2013 respectively. The amortization periods correspond to the year in which the project outcomes are expected to be implemented.

103.2 When does FortisBC anticipate it will have a final accounting of the costs to be posted to each of these three accounts?

Response:

Typically, final costs are known within approximately three months following the conclusion of the regulatory process. The Company expects to have final costs for the 2012-13 RRA and 2012 ISP in early 2012, the rate structure applications during 2012, and the irrigation customer consultation during 2013.

103.3 Why are costs associated with the 2011 Revenue Requirement still a "forecast"? Are the costs actually incurred still not known?

Response:

The costs of the 2011 Revenue Requirements proceeding are the final costs.

104.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 5, page 38 and Tab7, Table 1-E

104.1 What gives rise to the reduction in Lag Days for Tariff Revenue starting in 2012?

Response:

The Lag Days for Tariff Revenue is a calculation of the usage of electricity by a customer and the time it takes for FortisBC to receive payment for the electricity. The reduction in Lag Days in 2012 is a result of efficiencies to reduce the time between use and revenue collection. The total time to read a meter, produce a bill, deliver the bill and collect the funds has been reduced on average by seven days. Efficiencies that have been realized are in:

a. Increased eBilling;

b. Improved Collection Processes; and

c. Automation of various billing and collections processes.

104.2 What gives rise to the increase in Lag Days for Miscellaneous Revenue starting in 2012?

Response:

The increase in Lag Days for Miscellaneous Revenue starting in 2012 is caused by the increase of wheeling revenue and connection charges. Lag Days are a factor of the number of days funds are outstanding after a service or good are sold and the amount of money outstanding. The dollar amount of both connection charges and wheeling revenue has increased. An increase in dollar amounts increases the weighting for these items in the group of items that make up Miscellaneous Revenue. The increase in dollar weighting increases the number of Lag Days.

104.3 What gives rise to the increase in Lag Days for Employee Benefits starting in 2012?

Response:

FortisBC has restructured the way Employee Benefits are grouped to produce a better representation of the way the benefit program works. As a result of this re-grouping, the payout terms and timing were adjusted, which in turn resulted in increased Lag Days.

105.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 6, page 117

105.1 What avoided resource cost values are used to derive the TRC values in Table 7.0?

Response:

All of the benefit calculations presented in Section 7 of the 2012-13 Capital Plan filing, including Table 7.0, are based on the $101.34 per MWh blended long-term avoided power purchase cost presented in Table 3.2.1 of the 2012 long term DSM Plan. Please note, this value has been corrected as per Errata 2, which contains the applicable replacement pages.

105.2 If those values differ from those used in FortisBC's Long Term DSM Plan, please explain how they were derived.

Response:

The values do not differ.

106.0 Reference: FortisBC 2012-2013 Revenue Requirements Application, Tab 6, page 120

106.1 What other public utilities does FortisBC plan to collaborate with to direct-market the Rental Accommodation Program?

Response:

FortisBC plans to collaborate with BC Hydro and FortisBC Energy Inc.

106.2 Is this program contingent upon the participation of these public utilities and, if so, have they committed to such participation?

Response:

No, the program is not contingent upon BC Hydro and FortisBC Energy Inc participation but collaboration will be makes the program more consistent for customers and make programming more cost effective to design, implement and evaluate. Both utilities have committed verbally to work collaboratively with FortisBC on this program.

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AACE International Recommended Practice No. 18R-97

COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

TCM Framework: 7.3 – Cost Estimating and Budgeting

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AACE International Recommended Practice No. 18R-97

COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

TCM Framework: 7.3 – Cost Estimating and Budgeting

February 2, 2005

PURPOSE

As a recommended practice of AACE International, the Cost Estimate Classification System provides guidelines for applying the general principles of estimate classification to project cost estimates (i.e., cost estimates that are used to evaluate, approve, and/or fund projects). The Cost Estimate Classification System maps the phases and stages of project cost estimating together with a generic maturity and quality matrix, which can be applied across a wide variety of industries.

This addendum to the generic recommended practice provides guidelines for applying the principles of estimate classification specifically to project estimates for engineering, procurement, and construction (EPC) work for the process industries. This addendum supplements the generic recommended practice (17R-97) by providing:

- a section that further defines classification concepts as they apply to the process industries;
- charts that compare existing estimate classification practices in the process industry; and
- a chart that maps the extent and maturity of estimate input information (project definition deliverables) against the class of estimate.

As with the generic standard, an intent of this addendum is to improve communications among all of the stakeholders involved with preparing, evaluating, and using project cost estimates specifically for the process industries.

It is understood that each enterprise may have its own project and estimating processes and terminology, and may classify estimates in particular ways. This guideline provides a generic and generally acceptable classification system for process industries that can be used as a basis to compare against. It is hoped that this addendum will allow each user to better assess, define, and communicate their own processes and standards in the light of generally-accepted cost engineering practice.

INTRODUCTION

For the purposes of this addendum, the term process industries is assumed to include firms involved with the manufacturing and production of chemicals, petrochemicals, and hydrocarbon processing. The common thread among these industries (for the purpose of estimate classification) is their reliance on process flow diagrams (PFDs) and piping and instrument diagrams (P&IDs) as primary scope defining documents. These documents are key deliverables in determining the level of project definition, and thus the extent and maturity of estimate input information.

Estimates for process facilities center on mechanical and chemical process equipment, and they have significant amounts of piping, instrumentation, and process controls involved. As such, this addendum may apply to portions of other industries, such as pharmaceutical, utility, metallurgical, converting, and similar industries. Specific addendums addressing these industries may be developed over time.

This addendum specifically does not address cost estimate classification in nonprocess industries such as commercial building construction, environmental remediation, transportation infrastructure, “dry” processes such as assembly and manufacturing, “soft asset” production such as software development, and similar industries. It also does not specifically address estimates for the exploration, production, or transportation of mining or hydrocarbon materials, although it may apply to some of the intermediate processing steps in these systems.

The cost estimates covered by this addendum are for engineering, procurement, and construction (EPC) work only. It does not cover estimates for the products manufactured by the process facilities, or for research and development work in support of the process industries. This guideline does not cover the

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significant building construction that may be a part of process plants. Building construction will be covered in a separate addendum.

This guideline reflects generally-accepted cost engineering practices. This addendum was based upon the practices of a wide range of companies in the process industries from around the world, as well as published references and standards. Company and public standards were solicited and reviewed by the AACE International Cost Estimating Committee. The practices were found to have significant commonalities that are conveyed in this addendum.

COST ESTIMATE CLASSIFICATION MATRIX FOR THE PROCESS INDUSTRIES

The five estimate classes are presented in figure 1 in relationship to the identified characteristics. Only the level of project definition determines the estimate class. The other four characteristics are secondary characteristics that are generally correlated with the level of project definition, as discussed in the generic standard. The characteristics are typical for the process industries but may vary from application to application.

This matrix and guideline provide an estimate classification system that is specific to the process industries. Refer to the generic standard for a general matrix that is non-industry specific, or to other addendums for guidelines that will provide more detailed information for application in other specific industries. These will typically provide additional information, such as input deliverable checklists to allow meaningful categorization in those particular industries.

	Primary Characteristic	***Secondary Characteristic***			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

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Figure 1. – Cost Estimate Classification Matrix for Process Industries

CHARACTERISTICS OF THE ESTIMATE CLASSES

The following charts (figures 2a through 2e) provide detailed descriptions of the five estimate classifications as applied in the process industries. They are presented in the order of least-defined estimates to the most-defined estimates. These descriptions include brief discussions of each of the estimate characteristics that define an estimate class.

For each chart, the following information is provided:

- **Description:** a short description of the class of estimate, including a brief listing of the expected estimate inputs based on the level of project definition.
- **Level of Project Definition Required:** expressed as a percent of full definition. For the process industries, this correlates with the percent of engineering and design complete.
- **End Usage:** a short discussion of the possible end usage of this class of estimate.
- **Estimating Methods Used:** a listing of the possible estimating methods that may be employed to develop an estimate of this class.
- **Expected Accuracy Range:** typical variation in low and high ranges after the application of contingency (determined at a 50% level of confidence). Typically, this results in a 90% confidence that the actual cost will fall within the bounds of the low and high ranges.
- **Effort to Prepare:** this section provides a typical level of effort (in hours) to produce a complete estimate for a US$20,000,000 plant. Estimate preparation effort is highly dependent on project size, project complexity, estimator skills and knowledge, and on the availability of appropriate estimating cost data and tools.
- **ANSI Standard Reference (1989) Name:** this is a reference to the equivalent estimate class in the existing ANSI standards.
- **Alternate Estimate Names, Terms, Expressions, Synonyms:** this section provides other commonly used names that an estimate of this class might be known by. These alternate names are not endorsed by this Recommended Practice. The user is cautioned that an alternative name may not always be correlated with the class of estimate as identified in the chart.

CLASS 5 ESTIMATE	
Description: Class 5 estimates are generally prepared based on very limited information, and subsequently have wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systemic manner. Class 5 estimates, due to the requirements of end use, may be prepared within a very limited amount of time and with little effort expended—sometimes requiring less than an hour to prepare. Often, little more than proposed plant type, location, and capacity are known at the time of estimate preparation. **Level of Project Definition Required:** 0% to 2% of full project definition. **End Usage:** Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, project location studies, evaluation of resource needs and budgeting, long-range capital planning, etc.	**Estimating Methods Used:** Class 5 estimates virtually always use stochastic estimating methods such as cost/capacity curves and factors, scale of operations factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, and other parametric and modeling techniques. **Expected Accuracy Range:** Typical accuracy ranges for Class 5 estimates are - 20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances. **Effort to Prepare (for US$20MM project):** As little as 1 hour or less to perhaps more than 200 hours, depending on the project and the estimating methodology used. **ANSI Standard Reference Z94.2-1989 Name:** Order of magnitude estimate (typically -30% to +50%). **Alternate Estimate Names, Terms, Expressions, Synonyms:** Ratio, ballpark, blue sky, seat-of-pants, ROM, idea study, prospect estimate, concession license estimate, guesstimate, rule-of-thumb.

Figure 2a. – Class 5 Estimate

CLASS 4 ESTIMATE	
Description: Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval. Typically, engineering is from 1% to 15% complete, and would comprise at a minimum the following: plant capacity, block schematics, indicated layout, process flow diagrams (PFDs) for main process systems, and preliminary engineered process and utility equipment lists. **Level of Project Definition Required:** 1% to 15% of full project definition. **End Usage:** Class 4 estimates are prepared for a number of purposes, such as but not limited to, detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage.	**Estimating Methods Used:** Class 4 estimates virtually always use stochastic estimating methods such as equipment factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, the Miller method, gross unit costs/ratios, and other parametric and modeling techniques. **Expected Accuracy Range:** Typical accuracy ranges for Class 4 estimates are -15% to -30% on the low side, and +20% to +50% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances. **Effort to Prepare (for US$20MM project):** Typically, as little as 20 hours or less to perhaps more than 300 hours, depending on the project and the estimating methodology used. **ANSI Standard Reference Z94.2-1989 Name:** Budget estimate (typically -15% to + 30%). **Alternate Estimate Names, Terms, Expressions, Synonyms:** Screening, top-down, feasibility, authorization, factored, pre-design, pre-study.

Figure 2b. – Class 4 Estimate

CLASS 3 ESTIMATE	
Description: Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, preliminary piping and instrument diagrams, plot plan, developed layout drawings, and essentially complete engineered process and utility equipment lists. **Level of Project Definition Required:** 10% to 40% of full project definition. **End Usage:** Class 3 estimates are typically prepared to support full project funding requests, and become the first of the project phase “control estimates” against which all actual costs and resources will be monitored for variations to the budget. They are used as the project budget until replaced by more detailed estimates. In many owner organizations, a Class 3 estimate may be the last estimate required and could well form the only basis for cost/schedule control.	**Estimating Methods Used:** Class 3 estimates usually involve more deterministic estimating methods than stochastic methods. They usually involve a high degree of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring and other stochastic methods may be used to estimate less-significant areas of the project. **Expected Accuracy Range:** Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances. **Effort to Prepare (for US$20MM project):** Typically, as little as 150 hours or less to perhaps more than 1,500 hours, depending on the project and the estimating methodology used. **ANSI Standard Reference Z94.2-1989 Name:** Budget estimate (typically -15% to + 30%). **Alternate Estimate Names, Terms, Expressions, Synonyms:** Budget, scope, sanction, semi-detailed, authorization, preliminary control, concept study, development, basic engineering phase estimate, target estimate.

Figure 2c. – Class 3 Estimate

CLASS 2 ESTIMATE	
Description: Class 2 estimates are generally prepared to form a detailed control baseline against which all project work is monitored in terms of cost and progress control. For contractors, this class of estimate is often used as the "bid" estimate to establish contract value. Typically, engineering is from 30% to 70% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, piping and instrument diagrams, heat and material balances, final plot plan, final layout drawings, complete engineered process and utility equipment lists, single line diagrams for electrical, electrical equipment and motor schedules, vendor quotations, detailed project execution plans, resourcing and work force plans, etc. **Level of Project Definition Required:** 30% to 70% of full project definition. **End Usage:** Class 2 estimates are typically prepared as the detailed control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program.	**Estimating Methods Used:** Class 2 estimates always involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in great detail, and often involve tens of thousands of unit cost line items. For those areas of the project still undefined, an assumed level of detail takeoff (forced detail) may be developed to use as line items in the estimate instead of relying on factoring methods. **Expected Accuracy Range:** Typical accuracy ranges for Class 2 estimates are -5% to -15% on the low side, and +5% to +20% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances. **Effort to Prepare (for US$20MM project):** Typically, as little as 300 hours or less to perhaps more than 3,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes. **ANSI Standard Reference Z94.2-1989 Name:** Definitive estimate (typically -5% to + 15%). **Alternate Estimate Names, Terms, Expressions, Synonyms:** Detailed control, forced detail, execution phase, master control, engineering, bid, tender, change order estimate.

Figure 2d. – Class 2 Estimate

CLASS 1 ESTIMATE	
Description: Class 1 estimates are generally prepared for discrete parts or sections of the total project rather than generating this level of detail for the entire project. The parts of the project estimated at this level of detail will typically be used by subcontractors for bids, or by owners for check estimates. The updated estimate is often referred to as the current control estimate and becomes the new baseline for cost/schedule control of the project. Class 1 estimates may be prepared for parts of the project to comprise a fair price estimate or bid check estimate to compare against a contractor's bid estimate, or to evaluate/dispute claims. Typically, engineering is from 50% to 100% complete, and would comprise virtually all engineering and design documentation of the project, and complete project execution and commissioning plans. **Level of Project Definition Required:** 50% to 100% of full project definition. **End Usage:** Class 1 estimates are typically prepared to form a current control estimate to be used as the final control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program. They may be used to evaluate bid checking, to support vendor/contractor negotiations, or for claim evaluations and dispute resolution.	**Estimating Methods Used:** Class 1 estimates involve the highest degree of deterministic estimating methods, and require a great amount of effort. Class 1 estimates are prepared in great detail, and thus are usually performed on only the most important or critical areas of the project. All items in the estimate are usually unit cost line items based on actual design quantities. **Expected Accuracy Range:** Typical accuracy ranges for Class 1 estimates are -3% to -10% on the low side, and +3% to +15% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances. **Effort to Prepare (for US$20MM project):** Class 1 estimates require the most effort to create, and as such are generally developed for only selected areas of the project, or for bidding purposes. A complete Class 1 estimate may involve as little as 600 hours or less, to perhaps more than 6,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes. **ANSI Standard Reference Z94.2 Name:** Definitive estimate (typically -5% to + 15%). **Alternate Estimate Names, Terms, Expressions, Synonyms:** Full detail, release, fall-out, tender, firm price, bottoms-up, final, detailed control, forced detail, execution phase, master control, fair price, definitive, change order estimate.

Figure 2e. – Class 1 Estimate

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COMPARISON OF CLASSIFICATION PRACTICES

Figures 3a through 3c provide a comparison of the estimate classification practices of various firms, organizations, and published sources against one another and against the guideline classifications. These tables permits users to benchmark their own classification practices.

INCREASING PROJECT DEFINITION

<table>
<tr><th>AACE Classification Standard</th><th>ANSI Standard Z94.0</th><th>AACE Pre-1972</th><th>Association of Cost Engineers (UK) ACostE</th><th>Norwegian Project Management Association (NFP)</th><th>American Society of Professional Estimators (ASPE)</th></tr>
<tr><td rowspan="3">Class 5</td><td rowspan="3">Order of Magnitude Estimate
-30/+50</td><td rowspan="3">Order of Magnitude Estimate</td><td rowspan="3">Order of Magnitude Estimate
Class IV -30/+30</td><td>Concession Estimate</td><td rowspan="4">Level 1</td></tr>
<tr><td>Exploration Estimate</td></tr>
<tr><td>Feasibility Estimate</td></tr>
<tr><td rowspan="2">Class 4</td><td rowspan="4">Budget Estimate
-15/+30</td><td rowspan="2">Study Estimate</td><td rowspan="3">Study Estimate
Class III -20/+20</td><td rowspan="2">Authorization Estimate</td></tr>
<tr><td rowspan="2">Level 2</td></tr>
<tr><td rowspan="2">Class 3</td><td rowspan="2">Preliminary Estimate</td><td rowspan="2">Master Control Estimate</td></tr>
<tr><td>Budget Estimate
Class II -10/+10</td><td>Level 3</td></tr>
<tr><td>Class 2</td><td rowspan="3">Definitive Estimate
-5/+15</td><td>Definitive Estimate</td><td rowspan="3">Definitive Estimate
Class I -5/+5</td><td rowspan="3">Current Control Estimate</td><td>Level 4</td></tr>
<tr><td rowspan="2">Class 1</td><td rowspan="2">Detailed Estimate</td><td>Level 5</td></tr>
<tr><td>Level 6</td></tr>
</table>

Figure 3a. – Comparison of Classification Practices

INCREASING PROJECT DEFINITION

<table>
<tr><th>AACE Classification Standard</th><th>Major Consumer Products Company (Confidential)</th><th>Major Oil Company (Confidential)</th><th>Major Oil Company (Confidential)</th><th>Major Oil Company (Confidential)</th></tr>
<tr><td rowspan="2">Class 5</td><td rowspan="2">Class S
Strategic Estimate</td><td rowspan="2">Class V
Order of Magnitude Estimate</td><td>Class A
Prospect Estimate</td><td rowspan="2">Class V</td></tr>
<tr><td>Class B
Evaluation Estimate</td></tr>
<tr><td rowspan="2">Class 4</td><td rowspan="2">Class 1
Conceptual Estimate</td><td rowspan="2">Class IV
Screening Estimate</td><td>Class C
Feasibility Estimate</td><td rowspan="2">Class IV</td></tr>
<tr><td rowspan="2">Class D
Development Estimate</td></tr>
<tr><td rowspan="3">Class 3</td><td rowspan="3">Class 2
Semi-Detailed Estimate</td><td rowspan="2">Class III
Primary Control Estimate</td><td rowspan="2">Class III</td></tr>
<tr><td rowspan="2">Class E
Preliminary Estimate</td></tr>
<tr><td rowspan="2">Class II
Master Control Estimate</td><td rowspan="2">Class II</td></tr>
<tr><td>Class 2</td><td rowspan="2">Class 3
Detailed Estimate</td><td>Class F
Master Control Estimate</td></tr>
<tr><td>Class 1</td><td>Class I
Current Control Estimate</td><td>Current Control Estimate</td><td>Class I</td></tr>
</table>

Figure 3b. – Comparison of Classification Practices

INCREASING PROJECT DEFINITION

<table>
<tr><th>AACE Classification Standard</th><th>J.R. Heizelman, 1988 AACE Transactions [1]</th><th>K.T. Yeo, The Cost Engineer, 1989 [2]</th><th>Stevens & Davis, 1988 AACE Transactions [3]</th><th>P. Behrenbruck, Journal of Petroleum Technology, 1993 [4]</th></tr>
<tr><td>Class 5</td><td>Class V</td><td>Class V
Order of Magnitude</td><td>Class III*</td><td>Order of Magnitude</td></tr>
<tr><td>Class 4</td><td>Class IV</td><td>Class IV
Factor Estimate</td><td rowspan="4">Class II</td><td rowspan="2">Study Estimate</td></tr>
<tr><td rowspan="2">Class 3</td><td rowspan="2">Class III</td><td rowspan="2">Class III
Office Estimate</td></tr>
<tr><td rowspan="2">Budget Estimate</td></tr>
<tr><td>Class 2</td><td>Class II</td><td>Class II
Definitive Estimate</td></tr>
<tr><td>Class 1</td><td>Class I</td><td>Class I
Final Estimate</td><td>Class I</td><td>Control Estimate</td></tr>
</table>

[1] John R. Heizelman, ARCO Oil & Gas Co., 1988 AACE Transactions, Paper V3.7
[2] K.T. Yeo, The Cost Engineer, Vol. 27, No. 6, 1989
[3] Stevens & Davis, BP International Ltd., 1988 AACE Transactions, Paper B4.1 (* Class III is inferred)
[4] Peter Behrenbruck, BHP Petroleum Pty., Ltd., article in Petroleum Technology, August 1993

Figure 3c. – Comparison of Classification Practices

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ESTIMATE INPUT CHECKLIST AND MATURITY MATRIX

Figure 4 maps the extent and maturity of estimate input information (deliverables) against the five estimate classification levels. This is a checklist of basic deliverables found in common practice in the process industries. The maturity level is an approximation of the degree of completion of the deliverable. The degree of completion is indicated by the following letters.

- None (blank): development of the deliverable has not begun.
- Started (S): work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): the deliverable has been reviewed and approved as appropriate.

	ESTIMATE CLASSIFICATION				
General Project Data:	**CLASS 5**	**CLASS 4**	**CLASS 3**	**CLASS 2**	**CLASS 1**
Project Scope Description	General	Preliminary	Defined	Defined	Defined
Plant Production/Facility Capacity	Assumed	Preliminary	Defined	Defined	Defined
Plant Location	General	Approximate	Specific	Specific	Specific
Soils & Hydrology	None	Preliminary	Defined	Defined	Defined
Integrated Project Plan	None	Preliminary	Defined	Defined	Defined
Project Master Schedule	None	Preliminary	Defined	Defined	Defined
Escalation Strategy	None	Preliminary	Defined	Defined	Defined
Work Breakdown Structure	None	Preliminary	Defined	Defined	Defined
Project Code of Accounts	None	Preliminary	Defined	Defined	Defined
Contracting Strategy	Assumed	Assumed	Preliminary	Defined	Defined
Engineering Deliverables:					
Block Flow Diagrams	S/P	P/C	C	C	C
Plot Plans		S	P/C	C	C
Process Flow Diagrams (PFDs)		S/P	P/C	C	C
Utility Flow Diagrams (UFDs)		S/P	P/C	C	C
Piping & Instrument Diagrams (P&IDs)		S	P/C	C	C
Heat & Material Balances		S	P/C	C	C
Process Equipment List		S/P	P/C	C	C
Utility Equipment List		S/P	P/C	C	C
Electrical One-Line Drawings		S/P	P/C	C	C
Specifications & Datasheets		S	P/C	C	C
General Equipment Arrangement Drawings		S	P/C	C	C
Spare Parts Listings			S/P	P	C
Mechanical Discipline Drawings			S	P	P/C
Electrical Discipline Drawings			S	P	P/C
Instrumentation/Control System Discipline Drawings			S	P	P/C
Civil/Structural/Site Discipline Drawings			S	P	P/C

Figure 4. – Estimate Input Checklist and Maturity Matrix

REFERENCES

ANSI Standard Z94.2-1989. **Industrial Engineering Terminology: Cost Engineering**.
AACE International Recommended Practice No.17R-97, **Cost Estimate Classification System**.

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December 8, 2010

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW"), collectively the "Terasen Utilities"

Automatic Adjustment Mechanism Review - British Columbia Utilities Commission ("BCUC" or the "Commission") Order No. G-158-09 Compliance Filing

On May 15, 2009, the Terasen Utilities filed their Return on Equity ("ROE") and Capital Structure Application ("Application"), requesting an increase in ROE, elimination of the Automatic Adjustment Mechanism ("AAM"), the setting of the TGI's ROE as the benchmark ROE, and an increase to the common equity component of TGI's capital structure.

In its decision accompanying Order No. G-158-09 ("Decision"), dated December 16, 2009, the Commission directed that the AAM that had been used to determine the ROE of the Terasen Utilities on an annual basis be eliminated. The Commission also directed TGI to complete a study of alternative formulae and report to the BCUC by December 31, 2010:

> *A key consideration in the determination of whether to retain, amend or eliminate the AAM is whether the ROE produced by application of the formula for 2010 is reasonably comparable to the ROE determined by the Commission Panel from the evidence before it. The Commission's calculation of the ROE for 2010, as derived from the adjustment mechanism, is 8.43 percent, compared to the Commission Panel's determination that the appropriate ROE for TGI in 2010 is 9.50 percent. The Commission Panel determines that, in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard.*
>
> *The Commission Panel agrees that a single variable is unlikely to capture the many causes of changes in ROE and that in particular the recent flight to quality has driven down the yield on long-term Canada bonds, while the cost of risk has been priced upwards.*
>
> *In the Commission Panel's opinion, reliance on CAPM by Canadian regulatory agencies has also contributed to the divergence between Canadian and US allowed ROEs. In light of the limited weight given by the Commission Panel to CAPM in determining the ROE for TGI for 2010, it would seem inconsistent to retain the adjustment mechanism.*
>
> ***Accordingly the Commission Panel directs that the AAM be eliminated. TGI is directed to complete its study of alternative formulae and report to the Commission by December 31, 2010.***

As a result of the Decision, the Terasen Utilities retained Concentric Energy Advisors to conduct a full study of AAMs used in North America. This letter and attached report of

Concentric Energy Advisors have been prepared to comply with the directive in BCUC Order No. G-158-09.

Background to Automatic Adjustment Mechanisms

Until recently, the mechanism to adjust ROEs on an annual basis was through the use of an AAM, which came into effect in the mid-1990s and was adopted by many regulators across jurisdictions in Canada. In 1994, the BCUC was the first regulator in Canada to establish an AAM for calculating the allowed ROE on an annual basis, based on long-term Canada bond yields; and the BCUC determined BC Gas Utility Ltd. (now Terasen Gas Inc.) to be the benchmark low-risk utility. The allowed ROEs for other investor-owned utilities regulated by the BCUC (such as TGVI and TGW and FortisBC) were to be determined by adding to the benchmark ROE a company specific risk premium.

The use of a formula approach to ROE provided value to both utilities and customers in that it produced efficiency in regulatory process and therefore reduced costs. Over the last several years, however, the AAM has been increasingly under scrutiny in many jurisdictions for failure to meet the fair return standard. The validity of the AAM was examined closely in various regulatory jurisdictions across Canada during 2008 and 2009, with growing concerns about reliance on a single variable, the Government of Canada bond yield, and about the AAM overestimating the sensitivity of the utility ROE to changes in the Government of Canada bond yield. These concerns were highlighted during the 2008 and 2009 financial crisis when the changing capital markets (and particularly government bond yields) resulted in low ROEs and unfair rates of return.

The table below summarizes the history of AAM and the result of the recent AAM reviews by regulatory bodies in Canada.

Regulator	AAM Adopted	Recent Decision	Decision/Order Number	Release Date
British Columbia Utilities Commission (BCUC)	1994	Eliminated	G-158-09	December 16, 2009
National Energy Board (NEB)	1995	Terminated	N/A	October 8, 2009
Public Utilities Board of Manitoba (PUBM)*	1995	-	-	-
Ontario Energy Board (OEB)	1997	Modified	EB-2009-0084	December 11, 2009
Newfoundland and Labrador Board of Commissioners of Public Utilities (NL PUB)	1998	Maintained	P.U.43 (2009)	December 24, 2009
Québec Régie de l'énergie (Régie)	1999	Maintained	D-2009-156	December 7, 2009
Alberta Utilities Commission (AUC)	2004	Suspended	2009-216	November 12, 2009

*Note: PUBM has not have a formal review, but has abandoned using an AAM in recent years

In addition to BCUC's Decision, the AAM was recently abandoned by the National Energy Board ("NEB"), suspended by the Alberta Utilities Commission ("AUC"), and modified by the Ontario Energy Board ("OEB").

The NEB, on October 8, 2009, decided that the 1994 multi-pipeline ROE Formula was no longer in effect due to the considerable changes in financial and economic circumstances.

Similarly, the AUC's 2009 Generic Cost of Capital Decision resulted in suspension of the application of the ROE AAM. Some of the reasons that led to these changes, requiring a fair return on equity for Alberta utilities, were, as indicated in the decision, increased economic globalization, performance of the financial markets, financial performance of utilities, anticipated infrastructure expansion in Alberta, the financial crisis that began in 2007, and the growing differential between corporate bond yields and government bonds. The AUC has initiated a proceeding to consider whether to implement an annual ROE AAM in 2011.

On December 11, 2009, the OEB reset and refined its AAM, changing the allowed ROE by 50% of the change in forecast long-term Canada bond yields and 50% of the change in observed A rated utility bond index over the 30-year Canada Bond yield. This decision came about to address the relatively low ROE level, and the adjustment parameters were refined to reduce the sensitivity to changes in government bond yields.

An AAM was maintained but modified by the Québec Régie de l'énergie ("Régie") in its decision (D-2009-156), dated December 7, 2009, and similarly in Newfoundland and Labrador Board of Commissioners of Public Utilities ("NL PUB") decision (Order No. P.U. 43 (2009) dated December 24, 2009). The Public Utilities Board of Manitoba ("PUBM") has not yet initiated a formal review process to assess the continued use of the AAM; however, it has abandoned the use of AAM in recent years and only "uses the formula as an upper bound reasonableness check for return determinations for Centra Gas"[1].

The Terasen Utilities' Position and Recommendation

The use of AAM is only appropriate when it results in returns that meet the fair return standard. This means that the starting point or benchmark rate of return needs to be set at a level that meets the fair return standard before it can be adjusted to produce fair and reasonable returns. In the U.S., the use of AAM is less common, and in instances where such a mechanism is used, it is only applied to a starting point ROE that is fair. The Terasen Utilities have not found a formula in Canada or the U.S. that ensures fair and reasonable returns over time, and that meets the fair return standard, although a couple of those identified in the Concentric report came somewhat close to the BCUC's 2009 Decision in a backcast analysis.

In their Application, the Terasen Utilities requested an allowed ROE for TGI, the Benchmark ROE, to be set at 11%. In the same Application, the Terasen Utilities maintained that an AAM should:

1. be relatively simple to understand and apply;

1 Please refer to Concentric Energy Advisors report

2. be based on changes in one or more reasonably available and verifiable variables;
3. exclude changes in variables due to abnormal market events;
4. incorporate variables which vary in a quantifiable way with the utility cost of equity; and
5. incorporate variables which are not vulnerable to changes caused by company-specific circumstances which may not impact on the cost of equity for the utilities to which the formula applies.

The Terasen Utilities believe that the same criteria would be necessary to underpin an AAM if an AAM formula were to be introduced in the future. Further, should an AAM be implemented it is critical that the starting point be set at a level that meets the fair return standard. Given this requirement, the recency of the Decision in late 2009 and the gradual economic recovery, the Terasen Utilities are not proposing that the Commission adopt a formulaic AAM at this time.

On November 15, 2010, the OEB released its determination of the benchmark ROE for Ontario utilities subject to its formula for 2011 as 9.66%, a change of only 9 basis points from 2010. The Terasen Utilities submit that this suggests there would be little benefit derived from re-examining cost of capital at this time or introducing a new AAM in British Columbia.

In the event the Commission considers adopting an AAM in the future, the Terasen Utilities believe that such an AAM should be based on the principles outlined in the attached report prepared by Concentric Energy Advisors, and believe that the current 9.5% ROE benchmark and the related economic parameters from the Fall of 2009 should be used as the starting point until a new comprehensive review of the cost of capital for a benchmark utility is completed. Additionally, the Terasen Utilities submit that if a new AAM were to be considered, that the ROE for TGVI and TGW should continue to be set with reference to the benchmark ROE established for TGI by adding a utility specific risk premium, which has been a successful approach in BC.

Sincerely,

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC. and
TERASEN GAS (WHISTLER) INC.

Original signed by:

Scott A. Thomson
Executive Vice President, Finance, Regulatory & Energy Supply

Attachment

Terasen Gas Inc.
Terasen Gas (Vancouver Island) Inc. and
Terasen Gas (Whistler) Inc.
(Collectively the "Terasen Utilities")

A Review of Automatic Adjustment Mechanisms
for
Cost of Capital

November 29, 2010

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INTRODUCTION

Concentric understands that pursuant to the British Columbia Utilities Commission's ("BCUC" or "Commission") Return on Equity ("ROE") and Capital Structure Order No. G-158-09, dated December 16, 2009, for Terasen Gas Inc. ("TGI" or "Terasen"), Terasen Gas (Vancouver Island) Inc. ("TGVI"), and Terasen Gas (Whistler) Inc. ("TGW") (collectively referred to as the "Terasen Utilities"), the Commission eliminated the formulaic ROE adjustment mechanism determining that the returns it produced were "insufficient to meet the fair return standard."[1]

The automatic adjustment mechanism ("AAM") was originally established in 1994 to adjust the 1995 rate of return on common equity for BC Gas Utility Ltd. (now TGI), Pacific Northern Gas Ltd., and West Kootenay Power Ltd. (now FortisBC Inc.). As a precursor to that Decision, the Commission had convened an evidentiary proceeding to evaluate processes or mechanisms that might be employed to improve the determination of ROE and capital structures, particularly in terms of process.[2] Ultimately, in its decision, after considering stakeholder evidence, the Commission established a process whereby the benchmark ROE for a low risk, high grade utility would be determined in a generic cost of capital proceeding and would be adjusted annually using an AAM based on long term bond yields. For purposes of determining the utility specific ROE and capital structure, the Commission would consider the utility's relative risk versus the benchmark utility and would adjust ROE and/or capital structure to account for differences in risk between the utility and the generic benchmark.

The years that followed produced a steady decline in interest rates and consistently lower ROE results. In 2008 and 2009, government bond yields, which served as the basis of the BCUC AAM, continued their decline to unprecedented low levels while corporate risk premiums and corporate capital costs spiked. Over the period since implementation of the AAM, Canadian utilities that were once receiving ROEs in parity with U.S., were receiving ROE awards 200 basis points lower than their U.S. counterparts. These factors illuminated the inherent flaws in the AAM that the Commission noted in its recent Order. Ultimately, the Commission determined that "a single variable is unlikely to capture the many causes of changes in ROE"[3] and as such, discontinued the AAM. Specifically, the Commission found:

> *A key consideration in the determination of whether to retain, amend or eliminate the AAM is whether the ROE produced by application of the formula for 2010 is reasonably comparable to the ROE determined by the Commission Panel from the evidence before it. The Commission's calculation of the ROE for 2010, as derived from the adjustment mechanism, is 8.43 percent, compared to the Commission Panel's determination that the appropriate ROE for TGI in 2010 is 9.50 percent. The Commission Panel determines that, in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard.*

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1 In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision, G-158-09, December 16, 2009 at 72.

2 In the Matter of Return on Equity, BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd. Decision G-35-94, June 10, 1994, at 2.

3 In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision, G-158-09, December 16, 2009 at 73.

> *The Commission Panel agrees that a single variable is unlikely to capture the many causes of changes in ROE and that in particular the recent flight to quality has driven down the yield on long term Canada bonds, while the cost of risk has been priced upwards.*
>
> *In the Commission Panel's opinion, reliance on CAPM by Canadian regulatory agencies has also contributed to the divergence between Canadian and US allowed ROEs. In light of the limited weight given by the Commission Panel to CAPM in determining the ROE for TGI for 2010, it would seem inconsistent to retain the adjustment mechanism.*
>
> *Accordingly the Commission Panel directs that the AAM be eliminated. TGI is directed to complete its study of alternative formulae and report to the Commission by December 31, 2010.*[4]

To that end, the Terasen Utilities have retained Concentric Energy Advisors ("Concentric") to assist them with the development of a responsive filing to the Commission. Concentric has conducted extensive research and analysis regarding the Canadian ROE formula and the returns it has historically produced, in addition to analyzing the relative comparability of Canadian and U.S. utilities. Concentric had also developed a formulaic recommendation in Alberta and Ontario, which recognized the importance of litigated North American authorized returns for ROE determinations in Canada, and the integration of capital markets and similarity of regulatory models and corresponding risks for utilities in the two countries. Our discussion in this Report is underpinned by the considerable research we have conducted on these topics in connection with the following studies:

- A Comparative Analysis of Return on Equity of Natural Gas Utilities, prepared for the Ontario Energy Board by Concentric Energy Advisors, June 14, 2007;
- A Comparative Analysis of Return on Equity for Electric Utilities, prepared for the Coalition of Large Distributors ("CLD") and Hydro One Networks Inc. by Concentric Energy Advisors, June 2008;
- Concentric's Testimony before the AUC in its 2009 Generic Cost of Capital Proceeding, Application No. 1578571 / Proceeding ID. 85, on behalf of the ATCO Utilities, November 20, 2008; and most recently
- Concentric's Testimony and Presentation before the OEB in its 2009 Consultative Process on Cost of Capital, EB-2009-0084, on behalf of each Enbridge Gas Distribution, Inc. and Hydro One and the Coalition of Large Electric Distributors[5], individually, September 2009.

In order to assist the Terasen Utilities with their filing to the Commission, Concentric has examined the use of ROE formulas in other jurisdictions, contrasted these approaches with alternatives, considered the relative merits of these approaches and prepared this report summarizing our findings. Concentric is not recommending that a formula be adopted, but has reviewed and summarized the formulas in existence or that have been proposed in other jurisdictions. Additionally, Concentric has identified attributes that should be considered in the construction of an AAM in the event that one is adopted in the future.

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4 In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision, G-158-09, December 16, 2009 at 72.

5 The Coalition of Large Distributors consists of the following members: Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, Powerstream Inc., Toronto Hydro-Electric Systems Limited, and Veridian Connections Inc.

The remainder of this report is organized according to the following topics: Section 1 provides an overview of formulaic approaches to cost of capital in Canada and the U.S., and a brief overview of cost of capital practices overseas. Section 2 identifies desirable formula attributes. Section 3 provides an evaluation of alternative formulaic approaches, either in practice or proposed in other jurisdictions. Section 4 describes five alternatives for consideration by the Commission, and Section 5 summarizes our conclusions.

1. Cost of Capital Formulas

Regulators in both Canada and the U.S. consider three primary factors when establishing a just and reasonable allowed return. These factors are: 1) capital attraction; 2) financial integrity; and 3) comparable returns. That is, the authorized return must allow the regulated utility to attract capital on reasonable terms under a variety of different market conditions, to maintain its financial integrity and borrowing capacity, and to offer investors the opportunity to earn a return comparable to other businesses with commensurate risks. Canadian regulators are guided by the benchmark ROE decision *Northwestern Utilities v. City of Edmonton* (1929)[6], U.S. regulators are guided by court decisions including *Federal Power Commission v. Hope Natural Gas* (1944)[7] and *Bluefield Water Works and Improvement Company v. PSC of W. Va.* (1923)[8], and these decisions are also cited extensively in Canada.

The use over the past two decades of formulas or AAMs applied to the utility cost of capital had, until recently, evolved to be the 'norm' in Canada, but remains an exception among U.S. regulators. The formulaic methodology provides an approach to approximating the results of periodic rate hearings, without having to expend time and resources for a full evidentiary rate hearing on cost of capital. At the center of the Canadian movement towards a formulaic methodology has been a desire for improved regulatory efficiency through a generic approach to an often contentious issue in the context of a litigated rate proceeding or settlement process. In Canada, we have seen a re-evaluation of the use of AAMs over the past two years. The following sections highlight the use of formulaic approaches and prevailing cost of capital practices in Canada, the U.S., and selectively overseas.

a. Canada

In Canada, the adoption of a formulaic approach to setting regulated authorized equity returns was first established by the British Columbia Utilities Commission in 1994. According to a regulatory history compiled by Major and Priddle[9], through the mid-1990s Canadian utilities typically filed rate applications every one or two years, with ROEs set using one or more of four approaches: Comparable Earnings (CE), Discounted Cash Flow (DCF),

6 http://csc.lexum.umontreal.ca/en/1961/1961scr0-392/1961scr0-392.html
7 http://supreme.justia.com/us/320/591/case.html
8 http://supreme.justia.com/us/262/679/case.html
9 'The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results Implications", Hon. John C. Major, Former Justice, Supreme Court of Canada and Roland Priddle, Former Chair of the National Energy Board, March 2008.

Capital Asset Pricing Model (CAPM), or Equity Risk Premium (ERP). The adoption of a generic approach to ROE was ushered in by the following factors:

> *The context for the search by Canadian regulators for a generic approach to ROE was characterized by: frequent rate applications; repetitive evidence, often provided by the same expert witnesses, on the three principal tests; growing disenchantment with the CE and DCF tests; and increasing reliance on the ERP approach. That search was led by the BC Commission which "…was the first regulatory agency in Canada to examine the applicability of a generic, formula-based approach to setting natural gas or electric ROE as a means of improving the efficiency or effectiveness of the regulatory process*."[10]

Following the precedent set by the BC Utilities Commission in 1994, several other regulatory bodies in Canada followed suit: the National Energy Board ("NEB") (1995), Manitoba (1995), Ontario (1997), Newfoundland and Labrador (1998), Quebec (1999), and Alberta (2004).[11] Concentric has identified 6 Canadian provinces in addition to the NEB that implemented a formulaic approach to adjusting ROE, although the majority of these (NEB, BC, Manitoba and Alberta) are either terminated, under review or suspension,[12] and the Newfoundland and Labrador Board invited Newfoundland Power to propose changes to the formula in its most recent decision.[13]

In the case of the BC formula, the coefficient was initially set at 1.0[14] at the time the formula was established in 1994 and was subsequently changed to 0.80[15] and then to 0.75[16]. Withstanding current developments around the formula in Ontario, Alberta, Manitoba and the NEB, the formula that has been prevalent in the majority of Canadian provinces had settled on the following equation:

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10 Ibid., p.14.

11 Ibid, pp.15-16.

12 The NEB terminated the formula in October 2009, See NEB Reasons for Decision Multi-Client RH-R-2-94, (October 2009), part 1.2, *"Whatever the reason, given the vast experience the industry has gained in reaching negotiated settlements over the past 15 years, the Board is of the view that it is neither necessary nor appropriate to replace the RH-2-94 Decision with another multi-pipeline cost of capital decision at this time. Accordingly, the RH-2-94 Decision will not continue to be in effect."* Similarly, the BC Commission terminated the formula in December 2009, See Commission Order G-158-09, (December 2009), part 5, at 73, "*The Commission has accordingly directed that the automatic adjustment mechanism be eliminated*." The Manitoba Commission no longer uses the formula to make ROE determinations, but rather sets return based upon targeted debt/equity ratios of 75/25. The Board still uses the formula as an upper bound reasonableness check for return determinations for Centra Gas. *See* Manitoba Board Orders 103/05 and 115/05, (October 2005), part 1.(a), at 3 *"regulatory approach alternatives – the Board confirms its intention to use both the Rate Base Rate of Return and Cost of Service methodologies, with Rate Base Rate of Return to be a test of the maximum allowable return to MH".* The Alberta Commission has suspended the formula and will consider whether to reinstate the formula in the next generic proceeding. See AUC Decision 2009-216 (November 12, 2009), part 79 & 81. *"The Commission has decided to suspend the application of the existing, or any, ROE adjustment formula. The Commission has set a generic ROE for 2009 and 2010 of 9.0 percent. The same ROE will be employed for 2011 on an interim basis….In 2011, the Commission will initiate a proceeding to consider the final ROE for 2011 and to consider whether to implement an annual ROE adjustment formula".*

13 Newfoundland and Labrador Board of Commissioners of Public Utilities, Reason for Decision: Order No. P.U. 43 (2009), p. 30.

14 BCUC Decision No. G-35-94, June 10, 1994.

15 BCUC Decision No. G-49-97, April 24, 1997.

16 BCUC Decision No. G-14-06, March 2, 2006.

$$ROE_t = ROE_{t-1} + 0.75 \times (LCBF_t - LCBF_{t-1})$$

Where ROE_t is the ROE for the upcoming period and ROE_{t-1} is the ROE for the previous period. The $LCBF_t$ is equal to the Long Canada Bond Forecast, made up of the average of the 10 year bond forecast 3 months out and 12 months out, plus the one month average historical spread between the 30-year and 10-year bond yield; and for any period t may be expressed as:

$$LCBF_t = \left[\frac{10\_CBF_{3,t} + 10\_CBF_{12,t}}{2}\right] + \sum_i \frac{30\_CB_{i,1} - 10\_CB_{i,1}}{i_t}$$

A brief overview of formulas currently in use in other Canadian provinces is provided in Figure 1 and Part 3 of this report.

b. United States

In the U.S., formulaic approaches to determining ROE have been adopted by relatively few regulatory jurisdictions, as litigated ROE proceedings remain the prevalent means for setting ROE. Typically, a formulaic ROE approach coincides with a broader alternative regulation or performance-based rate plan that includes formulaic adjustments to rate components in addition to performance measures and incentives. Though, there are a number of U.S. jurisdictions that operate under "formula rate plans"[17] very few utilize automatic formulaic mechanisms to adjust ROE.

Of those jurisdictions that have adopted the use of formulaic adjustments to ROE, prevailing practices lie on both ends of the spectrum of complexity, with very little in between. For example, at one end of the spectrum, is the "prescriptive approach" which lays the ground rules for conducting a comprehensive ROE Study using standard methodologies and removing areas of contention by prescribing data inputs and proxy group selection criteria. This approach has been employed by Mississippi and has been considered by New York[18] and most recently Connecticut.[19]

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17 "Formula Rate Plans", "Performance-based Rate Plans" or "Alternative Regulation Plans" are all commonly used terminology in the U.S. (and may be used interchangeably) to describe a comprehensive alternative incentive rate structure.

18 The New York commission also entertained the "uniform/prescriptive approach" in 1982 when it initiated a Generic Financing Proceeding primarily focused on maintaining the financial integrity of utilities through financial standards designed to maintain A credit ratings. This proceeding evolved to a 1991 re-examination of the adequacy of these standards in the face of increased industry competition for the telecommunications, electric, gas, and water industries. Following a two-year period involving separate working groups of utilities and other interested parties, each industry group recommended the adoption of a generic cost of equity formula. The electric/gas group formula equally weighted three methods: DCF (two-stage), CAPM (average of 4 results), and Comparable Earnings, and a twice-per-year determination to be applied to subsequent rate periods. The Commission never rendered a final decision in this proceeding. However, it has utilized the recommendations from this proceeding to guide allowed returns for utility companies in New York.

19 The state of Connecticut initiated an investigative inquiry in October 2009 "*to explore the need, desirability and feasibility of establishing a uniform methodology for determining return on equity (ROE) for public service companies during rates cases conducted pursuant to § 16-19 of the General Statutes of Connecticut (Conn. Gen. Stat.)*." Comments in that proceeding were filed earlier in the year and it appears that the DPUC is considering the "prescriptive approach" where standardized DCF and CAPM analyses are completed for a specified proxy group of companies. A final decision is anticipated in February 2011.

The second, more common approach to formulaic ROE adjustment mechanisms, is that which can be described as a simple formula, such as has been prevalent in Canada, requiring no interim ROE analyses at all. Vermont and California use simple formulas tied to bond yields, similar to the Canadian formula described above. How those formulas differ from the formula described earlier, is detailed in Part 3 of this Report.

Lastly, there are a handful of U.S. jurisdictions that fix ROE at a specified rate and do not make adjustments, but rather share overages and shortfalls with ratepayers. Alabama and Louisiana fall into this category.[20] And, there are several jurisdictions and the FERC[21] that use a formula to set parameters for the range of reasonable ROE determinations, but do not adjust ROE using a formula.[22] A brief overview of the AAMs in Canada and the U.S. is provided in Figure 1, and a more complete discussion of U.S. automatic adjustment mechanisms currently in practice and their inputs may be found in Part 3.

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20 The Alabama Commission adopted a rate stabilization approach to the cost of equity when it set an ROE range for Alabama Power equal to 13 to 14.5%, subject to an annual rate increase cap of 5%. For rate increases above the cap, the company was at risk, and rate increases below the cap are allowed up to the 14.5% limit. Similar mechanisms were established for Alabama Gas (1983) and Mobile Gas (2002), and remain in effect today. This type of program was motivated by concerns for controlling rate increases, and evolved during a period of relatively high inflation. Similarly, in Louisiana, Entergy Gulf States has been subject to an electric formula rate plan since 2004. The current plan incorporates a 150 basis point dead-band, i.e. 75 basis points above or below a benchmark ROE of 10.65%. If EGS' earned ROE falls below the lower end of the dead-band (that is 9.9%), the company is permitted to recover 60% of the shortfall up to the lower end of the dead-band from ratepayers. If EGS' earned ROE exceeds the upper end of the dead-band (that is 11.4%), the company must refund 60% of the excess to customers. The other electric and gas utilities in Louisiana operate under similar rate stabilization plans. However, only Louisiana Gas Service has a cap on the amount by which O&M expenses are allowed to increase each year (i.e., $39.9 million per year adjusted for inflation and customer levels).

21 While not completely formulaic, the FERC has applied a prescriptive approach to measuring ROE for regulated transmission utilities under its jurisdiction. For natural gas pipelines, the FERC specifies proxy group selection criteria, employs a two-stage DCF methodology, prescribes sources for analyst growth rates, prescribes appropriate weightings of growth rates to be used in the analysis, and prescribes a methodology for arriving at a reasonable range of ROE results from which the midpoint is selected. This method has evolved through case precedent (as has the methodology for electric transmission ROE determinations, which differ slightly from those of gas transmission ROE determinations). For relevant FERC proceedings that established the natural gas prescriptive approach to ROE, please refer to 84 FERC ¶61,081, Williston Basis Interstate Pipeline Company, Order on Initial Decision, Issued July 29, 1998; Opinion No. 414-A, 84 FERC ¶61,084, Issued July 29, 1998; and Opinion No. 414-B, 85 FERC ¶61,323.

22 In Virginia, Title 56, Chapter 23 of the Code of Virginia prescribed a formula to be used by the Virginia State Corporation Commission ("SCC") to set a ceiling and floor for authorized ROEs. The statute states: "*In such proceedings the Commission shall determine fair rates of return on common equity applicable to the generation and distribution services of the utility. In so doing, the Commission may use any methodology to determine such return it finds consistent with the public interest, but such return shall not be set lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of other investor-owned electric utilities in the peer group of the utility, nor shall the Commission set such return more than 300 basis points higher than such average.*" Similarly, in Florida, the PSC uses a leverage formula to set bounds around a range of returns based on a low-end equity ratio of 40% and a high-end ratio of 100% for its water utilities. The base ROE is determined through DCF and CAPM analyses using natural gas utilities as a proxy for water utilities. See Notice of Proposed Agency Action Order Establishing Authorized Range of Returns on Common Equity for Wastewater Utilities, Docket No. 090006-WS, Order No. PSC-09-0430-PAA-WS (June 19, 2009) "*Section 367.081(4)(f), Florida Statutes (F.S.), authorizes us to establish, not less than once each year, a leverage formula to calculate a reasonable range of returns on equity (ROE) for water and wastewater (W A W) utilities...Although Subsection 367.081 (4)(f), F.S., authorizes us to establish a range of returns for setting the authorized ROE for W A W utilities, we retain the discretion to set an ROE for W A W utilities based on record evidence in any proceeding.*"

c. ROE Practices Overseas

Looking abroad to the U.K., Netherlands and Australia, we find a reliance on price cap regulation and rates that are adjusted annually based upon inflation and productivity by the utilities. These countries (the U.K., Netherlands and Australia) each rely predominantly on a market based asset return or (WACC) methodology to set the initial base rates for a fixed period (3 to 5 years). None of these countries employ an AAM to set ROE. ROEs are set in regulatory proceedings.

All of the prevailing formulaic approaches that we have identified and their associated inputs are summarized in Figure 1.

Figure 1: North American Formulaic ROE Adjustment Mechanisms Currently in Effect

Formula Inputs	Jurisdiction: Ontario (new formula)	Quebec (former BC, Ontario and NEB) formula	Newfoundland and Labrador formula	Vermont formula	California formula	Mississippi formula
Forecast 10-year Government Bond Yield (Average of 3 months out and 12 months out forecast)	✓	✓	✓			
20 trading day average of 10-year U.S. Treasury yield				✓		
12 month average yield Moody's Baa or A utility bond yield					✓	
Spread between 10 and 30-year Government Bond Yield (daily differences for select prior month)	✓	✓	✓			
Spread between Long Canada Government Bond Yield and the Blooomberg Fair Value Canada 30-Year A-rated Utility Bond index	✓					
Inversely Applies Coefficient of 20% Δ in bond yield to Equity Risk Premium (same as 80% Δ in bond yield)			✓			
Coefficient of 75% Δ in bond yield		✓				
Coefficient of 50% Δ in bond yield	✓			✓	✓	
Equal weighting of DCF, Risk Premium and CAPM + 12.5 bps for flotation costs						✓
Incentives				✓		✓
Deadband				✓	✓	✓
Formula Applied Annually	✓	✓	✓	✓	✓	✓
Specified Review Period	✓				✓	

Upon examining the formulas adopted in Canada and the U.S., there are some common themes in terms of inputs and overall design elements. Generally, most formulas are tied to government or utility bond yields (only the Mississippi prescriptive ROE methodology does not utilize a bond yield directly for its adjustment mechanism). Of those formulae that rely on bond yields, a 30-year bond yield is the tenure of bonds more commonly adopted. The Canadian formulas tend to use a forecast 10-year bond yield plus the recent spread between 10 and 30-year bonds. The Vermont formula uses a historical average of the 10-year bond yield. The California formula and the newly adopted Ontario formula utilize a measure of the corporate long-term utility bond yield. In addition, in Ontario a portion of the long-term utility bond yield is forecast (the formula adds 0.50 of the change in the Long Canada Bond Forecast to 0.50 of the change in the yield spread between the A-rated Utility Bond and the Long Canada Bond from the base year.) In Canada, adjustment coefficients applied to changes in bond yields had generally been in the 0.75 range, but as is the case in Ontario above, there is movement towards a range of 0.50 as seen with U.S. formulas. In addition, several of the formulas are coupled with incentive mechanisms, deadbands, specified review periods, and all of the formulas are adjusted annually (subject to their deadbands).

2. Desirable Formula Attributes

Two perceived benefits of a formulaic adjustment mechanism are regulatory expediency and greater certainty for both the utility and regulator. As noted above, formulas generally update annually, without special proceedings or contentious battles between stakeholders. However, the tendency to set and forget the formula is also a primary drawback to the formulaic approach. When equity returns are generated on autopilot, there is a tendency to ignore or discount changing market conditions that may render the formulaic result unfair. There must be a balance that recognizes the need to periodically benchmark against traditional measures of required returns for regulated utilities. A functional ROE formula must be able to approximate the results that would have been produced in a rate-setting hearing process.

Establishing the starting point of the formula is the first step in the process. Great care must be exercised in establishing the initial ROE as the effects of any understatements or overstatements will be felt with each succeeding application of the formula. Concentric is of the view that the initial ROE should be set in accordance with traditional ROE setting methodologies, utilizing multiple approaches, based on a proxy group of companies with similar risk profiles, in a process where the regulatory Board hears evidence from the company and its stakeholders. Most jurisdictions go through this process each time ROE is set. A fully litigated regulatory process where stakeholder evidence is presented and heard by the commission generally provides a sound basis for a fair determination of ROE. As noted earlier, several jurisdictions have turned to the use of formulas to provide interim adjustments to ROE for estimated movements in equity markets between rate proceedings. The same regulatory objectives could be met without a formula by scheduling regular cost of capital proceedings within reasonable time frames. Periodic rate hearings encompass most of the desired attributes we consider in establishing a formulaic methodology. When utilizing an AAM, it is also important that the parameters of the formula are carefully selected. Otherwise, errors will have a compounding influence on the formulaic result as they accumulate over time.

If a formula is adopted, Concentric is of the opinion that any formulaic approach selected should give adequate consideration to the following criteria:

1. Tracks required utility equity returns
2. Ease of administration
3. Based on commercially accessible inputs
4. Promotes regulatory transparency
5. Forward-looking
6. Stability
7. Insulated from the effects of anomalous and transitory market conditions
8. Specified timetable for periodic review and/or rebasing of the formula
9. Reflects the capital market conditions faced by the utility.

Tracks Required Utility Equity Returns

The formulaic approach must accurately reflect investor-required equity returns amid varied economic and financial market conditions. A formula that relies exclusively on government bond yields, for example, may lose sight of influences in the bond market that do not affect the equities market and vice-versa. Bond yields and equity returns do not always move in tandem. For example, the sustained decline in interest rates in Canada over the last decade as a result of the monetary policy from the Federal Reserve Board and the Bank of Canada has resulted in increasingly lower formula-produced returns on equity, while litigated evidentiary proceedings in Canada and the U.S. were producing higher equity returns than those produced by the formula. Indeed, in the recent financial crisis and economic recession, credit spreads widened significantly and equity market volatility rose to unprecedented levels, ultimately causing government bond yields and corporate capital costs to move opposite to one another despite a historical positive relationship. Neither bond yield (government or corporate) provides a complete picture of required equity returns. Incorporating factors that estimate required utility equity returns or incorporating returns allowed in other jurisdictions into the formulaic adjustment mechanism might alleviate this problem. Such factors might include:

- An index of North American allowed equity returns for utilities
- DCF Calculation
- Equity Risk Premium or CAPM[23] Calculation
- Investor analyst sector or utility specific projections for ROE.

Ease of Administration

Regulators seeking to adopt formulas are generally looking for an ROE adjustment mechanism that can be updated annually without the need for a hearing process or supporting expert testimony. The process of hiring experts to provide opinions and supporting evidence on ROE issues is costly and time consuming. It is important that if an

[23] The CAPM methodology is an extension of the basic equity risk premium model. It is a theoretical model based on the investor objective of optimizing portfolio returns by minimizing systematic market risk. The CAPM model is often criticized for the subjectivity and controversy around its input parameters such as beta, the means to adjust beta, the appropriate risk free rate and the appropriate risk premium.

automatic adjustment mechanism is reintroduced, it should be readily administered by regulatory staff without the assistance of outside experts.

Based on Commercially Accessible Inputs

Formulas should utilize data that is commercially available and populated for both U.S. and Canadian companies. Often, subscription charges apply to data services (e.g., Bloomberg, DEX Universe Bond Indices), but these costs may be more than offset by the value of the data to the process.

Promotes Regulatory Transparency

Regulatory transparency refers to the openness of the process and predictability of outcomes by all stakeholders, i.e. the utility, creditors, investors, and ratepayers. A formulaic ROE that can be readily estimated by stakeholders promotes regulatory transparency, enabling investors to make forward projections based on widely understood data inputs. A formula with inputs that are not available to the stakeholders or that requires regulatory discretion in its application would not satisfy the objective of regulatory transparency as there is still uncertainty around the ultimate regulatory decision.

Forward-Looking

A formulaic ROE should provide an informed estimate of what investors will require in returns over the course of the applicable rate-setting period. For this reason, the use of yield projections and share price data are beneficial in providing a forward looking view of what is to come on the investment horizon. Both projected yield data and stock value per share data provide meaningful information as to what investors see for the future of a given credit issue or company valuation at the present time. Near-term historical data may be a reasonable proxy for projected data unless significant growth or anomalous market activity render recent history an inappropriate indicator for the projection period.

Stability

The formula should be responsive to changing market conditions but not overly sensitive to normal market volatility. It should have the stability to moderate the effects of temporary market movements so that regulators and utilities alike are not constantly making nominal changes to rates that would otherwise reverse themselves in the next period. Deadbands are used in several jurisdictions to avoid the recalculation of ROE and rates for minor changes in market conditions. If used, deadbands should strike a reasonable balance between triggering too often and not triggering often enough. A formula that is too sensitive to market volatility introduces unnecessary volatility to utility revenues and rates and results in inefficient rate revisions.

Insulated from the Effects of Anomalous and Transitory Market Conditions

Some formulaic approaches employ ceilings and floors to limit the movement of ROE from starting levels and/or trigger a review. The recent market collapse and recession of 2008 illustrated that a formula may produce inappropriate results under certain market conditions. Monitoring and setting limits based upon established thresholds such as: returns in other jurisdictions, credit spreads, changes in bond yields, changes in earnings growth, changes in stock prices, or substantial changes in ROE results may all provide valuable information to assist in the determination that the formula should be tested for appropriate results. Once such a condition is indentified, there must be an assessment and resolution process where the regulator and stakeholders arrive at an equitable solution for ensuring the fair return on equity for the upcoming period.

Specified Timetable for Periodic Review and/or Rebasing of the Formula

Any formulaic methodology should be accompanied by defined conditions that would trigger a review. A formula that remains on autopilot too long may yield inappropriate results. It is therefore necessary to routinely benchmark the formulaic result to other measures of ROE. We have observed that conditions may arise that would warrant a review, but without an established process the decision to re-evaluate the formula could be delayed by stakeholder deliberations on whether the formula is providing reasonable results. For that reason, Concentric recommends an established framework for rebasing the formula, i.e. every 3 to 5 years, unless there is substantial agreement among stakeholders that the formula is providing reasonable results. The periodic review, at a minimum, should incorporate tests beyond those upon which the formula is based. There is also value in allowing parties to petition for a review of the formula when and if they believe it is providing unreasonable results.

Reflects the Capital Market Conditions Faced by the Utility

When setting the ROE for a regulated utility, it is ideal to obtain data inputs reflecting capital market conditions faced by the utility. The integration of North American capital markets and the similarity of the legislative and regulatory processes have created a more homogenous market for utility capital. Formulas should strive to choose proxies carefully, so that risks borne by the proxy companies are representative of those to which the utility under consideration is subjected. Though no proxy is perfect, risk adjustments may be made for marked differences in risk profiles between the utility and its set of proxy companies.

3. Alternative Formulaic Approaches

a. A Study of Formulaic Inputs

The components of a cost of capital or ROE adjustment formula can be broken down into two fundamental functions. First, the inputs to approximate the movement of equity returns based upon an estimated relationship between the formula input factor and the returns utility equity investors require. Through our research, we have identified the following inputs and coefficients that are present in ROE automatic adjustment mechanisms:

- Forecast Government Bond Yield
- Historical Government Bond Yield
- Corporate Bond Yield
- Utility Bond Yield
- DCF, Risk Premium and CAPM Inputs
- Formula Coefficient.

Second, some formulas incorporate protective mechanisms that mitigate the impact of the formula under certain conditions. Examples of these are trigger mechanisms that prompt a review if a predetermined threshold is met, and predetermined periods for rebasing ROE. Some formulas employ ceilings and floors that are either fixed or tied to a variable, which provide a figurative rail to keep the formula returns on track. Other mechanisms may specify a materiality threshold for adjustment and employ a deadband in which no adjustment is made. Below is a list of measures that we have identified that moderate or rebase the results of the formula in certain conditions:

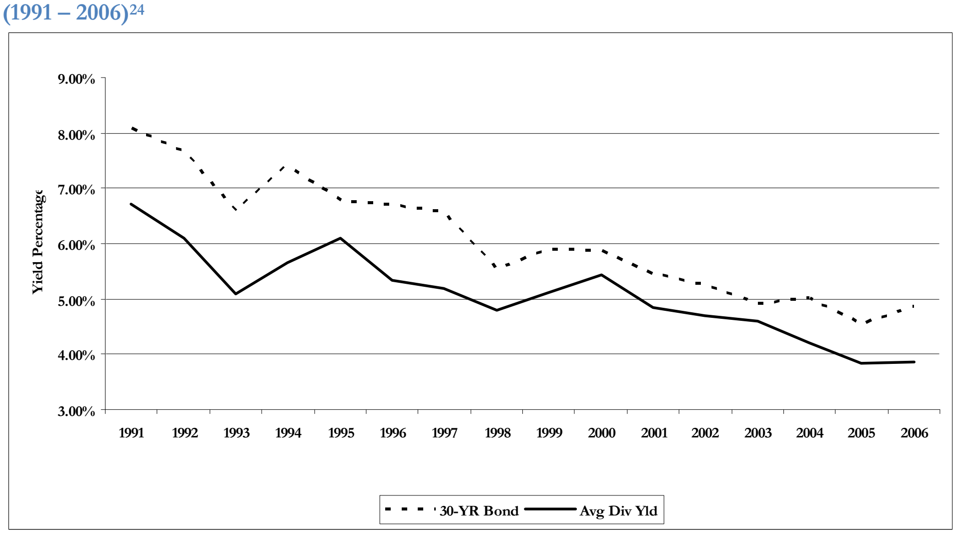
- Deadband
- Ceilings and Floors
- Trigger Mechanisms
- Review Period.

i. Inputs that Approximate the Movement of Equity Returns

As we detailed in our Report for the OEB in 2007, there is a strong historical relationship between utility dividend yields and bond yields. In that report, we stated:

> *There is significant academic research that establishes that utility stock prices are inversely related to the level of interest rates, and likewise that dividend yields and the level of interest rates are positively correlated. [Figure 2] depicts the strong positive relationship between average annual 30-year U.S. Treasury yields and the average annual dividend yields for a representative group of U.S. gas distribution utilities.*

[Figure 2]: Comparison of U.S. Gas Utility Dividend Yields and U.S. 30-Year Bond Yields (1991 – 2006)[24]



> *This strong positive relationship is attributed both to the capital (and debt) intensive nature of a utility, such that a decrease in debt capital costs will result in higher earnings and higher stock prices (lowering dividend yields), and to the fact that utilities' equity returns compete with debt yields in capital markets, as utilities are generally considered among investors to be relatively stable, lower risk investments.*

24 This analysis was provided in Concentric's Report to the OEB, "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (June 2007) at 12 [Clarification Added]. Dividend yields were represented for the average of all 15 natural gas distribution utilities covered by the Value Line Investment Survey's March 16, 2007 publication. 30-Year Treasury bond yields were obtained from Yahoo! Finance.

Similarly, bond yields are positively correlated to utility authorized equity returns as regulatory commissions recognize that the return they provide to equity holders should provide a premium over corporate borrowing costs. That premium varies with the level of interest rates and generally moves inversely to interest rates. Below, we have included an analysis of U.S. and Canadian bond yields, which demonstrates the relationship between authorized utility equity returns and both corporate and government bond yields using both Canadian and U.S. bond yield data. We have used U.S. authorized equity return data as a proxy for Canadian utility equity return data, since the prevailing authorized utility equity returns in Canada for the period under study were formulaically determined using bond yields as a direct input, creating a problem with circularity. Because the level of interest rates has trended similarly between Canada and the U.S., we believe it is reasonable to expect that equity returns would also trend similarly. As reflected by the large red circle, the sensitivity to government bond yields ranges from 0.2888 to 0.4657; and to corporate bond yields ranges from 0.4302 to 0.5205.

Table 1: Statistical Analysis Describing Sensitivity of Authorized Returns to Long Term Bond Yields

	Intercept	t-stat$_{\alpha}$	B	t-stat$_{x}$	R^2
RRA Quarterly Avg. Authorized Returns vs. 30-Year Government Bond Yield					
Quarterly weighted-average (weighted by the number of electric and gas cases) Q4 1989 - Q3 2010 (84 observations) versus the 30-Year U.S. Treasury Bond	8.4057	41.3305	0.4657	13.9068	0.7022
Quarterly weighted-average (weighted by the number of electric and gas cases) Q4 1989 - Q3 2010 (84 observations) versus the 30-Year Government of Canada Long Bond	9.3038	59.2100	0.2888	11.7477	0.6419
RRA Quarterly Avg. Authorized Returns vs. 30-Year A-Rated Utility Bond Yield					
Quarterly weighted-average (weighted by the number of electric and gas cases) versus Moody's A-rated Utility Bond Index Quarterly average (daily average for each month in the quarter then three months averaged) Q4 1989 - Q3 2010 (84 observations)	7.3311	27.3554	0.5205	14.4970	0.7193
Quarterly weighted-average (weighted by the number of electric and gas cases) versus Bloomberg Canada A-rated Utility Bond Index[25] Quarterly average (daily average for each month in the quarter then three months averaged) Q2 2002 - Q3 2010 (34 observations)	8.0691	16.4233	0.4302	5.0879	0.4472

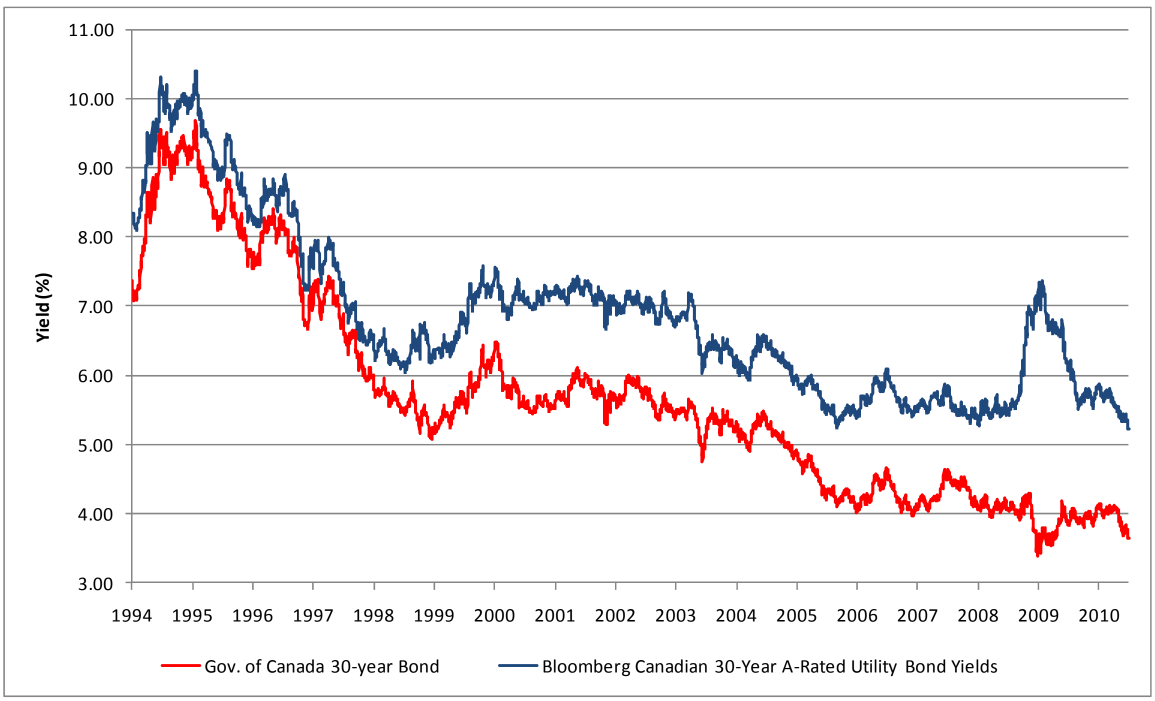
This level of sensitivity may be compared to the 0.75 coefficient which has prevailed in the Canadian ROE formula, where for every one percentage point change in government bond yields the return on equity moves by 0.75. In the analyses summarized in Table 1, the

25 The Bloomberg A-rated Utility Bond Yield Index was first reported on March 5, 2002.

regression results indicate that this sensitivity anticipated by the Canadian ROE formula has been overstated and is more appropriately in the range of 0.50.[26]

Generally, government bond yields and corporate bond yields enjoy a strong positive relationship. However, as Figure 3 shows, they do differ. Government bond yields are heavily influenced by changes in fiscal and monetary policy, whereas the influences of fiscal and monetary policy on interest rates may be very different than corporate risk. As a case in point, Figure 3 illuminates the divergence between corporate bonds and government bonds that occurred from September 2008 through early 2009, during the global economic crisis. The credit spreads increased dramatically as the corporate bond moved higher and the government bond moved lower. Today, those spreads have returned largely to their previous levels.

Figure 3: Corporate Utility A-Rated 30-Year Bond Yields versus Canadian Government 30-Year Bond Yields



As the Figure shows, corporate bond yields and government bond yields may become delinked. Corporate utility bond yields provide a better indication of the utility's true capital costs as the increase in corporate risk implied by the increase in credit spread will likely be at least paralleled on the equity side. It is a rare occurrence when debt carries a higher risk (credit spread) than equity (equity risk premium). This matter was recently considered by the California Commission, where its decision considered the relative merits of using a government bond yield versus a corporate bond yield as the platform for the ROE formula:

26 This conclusion is consistent with conclusions reached in the Concentric Energy Advisors comments filed on behalf of EGDI, OEB 2009 Consultative Process on Cost of Capital Review EB-2009-0084, September 8, 2009, at 5.

> *The purpose of an interest rate benchmark is to gauge changes in interest rates that also indicate changes in the equity costs of utilities. U.S. Treasuries are more sensitive to economic changes and risks in the international capital markets than utility bonds because they are bought and sold globally. However, U.S. utility bonds are generally affected less than Treasuries as a result of major shifts of international capital because a majority of U.S. utility bonds are traded within the U.S.*
>
> *Consistent with our use of utility bond interest rates in ROE, PBR, and MICAM proceedings and desire to use an index that more likely correlates and moves with utility industry risk, utility bonds should be adopted for the CCM (Cost of Capital Mechanism) index. In this regard, the Moody's Aa utility bond rates should be used for those utilities having an A credit rating and Moody's Baa utility bond interest rates for utilities having a B credit rating.*[27]

Though a formula tied to government or corporate bond yields may, with proper specification of inputs and a pre-determined process for review and calibration, provide a reasonable basis for an automatic adjustment mechanism for ROE, other jurisdictions have incorporated direct estimates of equity returns into their AAMs. For example, Mississippi utilizes a weighting of a series of ROE analyses, i.e. DCF, risk premium and CAPM, developed in accordance with prescribed parameters, to develop their adjustment mechanism. This methodology most closely emulates the evidence typically provided in a litigated rate process, but it is complex and would require greater staff resources for administration.

Other means of factoring equity returns into AAMs might include incorporating the ROEs authorized by other jurisdictions into the formulaic mechanism. Concentric proposed such a formula in Alberta and Ontario, where an equal weighting of the formulaic adjustment mechanism (specified with a coefficient of 0.50 and use of the Bloomberg 30-year A-rated utility bond yield) was combined with an index of North American allowed utility returns applied to the initial ROE.

ii. Inputs that Mitigate Revisions to Equity Returns

One cannot be sure that any of the formulaic approaches would satisfy the fairness standard over time. To provide a safeguard against the formula resulting in deficient or excess returns in a period of unanticipated capital market circumstances, there are a number of safeguards that may be employed to ensure that equity returns do not get too far off track.

<u>Deadband</u>

The deadband is a specified range in which no changes will occur. Deadbands used within a certain range promote regulatory efficiency by not changing the return portion of the utility's calculated revenue requirement for relatively small changes in the formulaic ROE. Recognizing that the ultimate objective is a fair return, a dead band is viable as long as the base ROE is fair, the expected deviation from the allowed return is neutral and fluctuations

27 *Application of Southern California Edison Company (U338E) for Authorized Cost of Capital for Utility Operations for 2008 and Related Matters*, Decision of ALJ Michael J. Galvin, mailed April 29, 2008, at 13.

do not jeopardize the financial integrity of the utility or overcompensate shareholders at the expense of ratepayers. The deadband is appropriate when regulatory efficiency can be optimized without sacrificing a fair return.

Ceilings and Floors

Ceilings and floors provide parameters around a formula, inhibiting any results that are either higher than the ceiling or lower than the floor. If the formula yields results outside of those parameters, the default result is either the ceiling or the floor. Ceilings or floors may not be symmetrical, and may be tied to inputs, ROE determinations, or ultimate revenue requirement increases (rate caps) produced by the formula.

Trigger Mechanism

Trigger mechanisms are generally used so that if the formula yields results outside of established limits, some action is taken. Often times, moving beyond the limit will trigger a review or rebasing of the formula. Trigger mechanisms may be tied to a benchmark (such as specified deviation from average North American litigated allowed returns), may be tied to changes in the formulaic inputs (such as specified changes in bond yield inputs), or may be tied to the actual result of the formula (symmetrical ceiling and floor established from the starting ROE).

Specified Review Period

A formal review proceeding may be implemented at specified time periods, where ROE may be reviewed, recalibrated and reset, if parties deem necessary. It provides certainty that the formula's ability to adequately track returns will be periodically addressed.

A more complete discussion of these formulaic inputs may be found at Appendix A.

b. Profiles of Formulaic ROE Adjustment Mechanisms

Concentric has identified formulas in use in Canadian and U.S. jurisdictions. A brief overview of each formula follows.

Ontario ROE Formula

The Ontario Energy Board recently decided in its 2009 Consultative Process that the specification of the relationship between interest rates and the equity risk premium in the then prevailing Ontario formula (described previously) would be improved by the addition of a term that incorporates corporate bond yields. The Board determined that it would use a utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-year A-rated utility Bond Index yield and the long Canada bond yield. The Board also determined that the sensitivity of the formula to bond yields should be reduced from 0.75 to a 0.50 adjustment factor for each 1 percent change in the long-term bond yield forecast. In addition, the Board provided that parties may ask the Board to review cost of capital policies when they feel it is appropriate or the Board may do so on its own initiative. The Board has determined that a review period of five years provides an appropriate balance between the need to ensure that the formula-generated ROE continues to meet the Fair Return Standard and the objective of maintaining regulatory efficiency and transparency. The current Ontario formula is given by the following equation:

$$ROE_t = ROE_{t-1} + \left[0.50 \times (LCBF_t - LCBF_{t-1}) + 0.50 \times \sum_i \frac{30\_CUtA\_B_{i,1} - 30\_CB_{i,1}}{i_t}\right]$$

In this formula, the long Canada Bond Forecast is combined in equal weighting with the Average daily Spread for the most recent three months, between A-rated Canadian Utility Bonds and 30-year Government of Canada Bonds. The Long Canada Bond forecast is given by the following equation:

$$LCBF_t = \left[\frac{10\_CBF_{3,t} + 10\_CBF_{12,t}}{2}\right] + \sum_i \frac{30\_CB_{i,1} - 10\_CB_{i,1}}{i_t}$$

Quebec

Similar to the former NEB, Ontario and BC Automatic Adjustment Mechanisms, Quebec's Automatic Adjustment Formula was adopted in 1999 by Decision D-99-11, case R-3397-98. The Formula was subsequently reviewed and renewed in 2004 by Decision D-2004-196, case R-3529-2004, and again in 2009 by Decision D-2009-156, case R-3690-2009 for the 2011 test year. The adjustment coefficient in the Automatic Adjustment Formula reflects 75% of the variation in the forecast rate of return on 30-year Canada bonds.[28] The Quebec formula is pictured in Section 1 of this Report.

Newfoundland and Labrador

The automatic adjustment formula was implemented as a result of Board Order P.U. 16 (1998-99). Calculation of the return on common equity is based on the equity risk premium model with 30-year Government of Canada bonds representing the risk-free rate. The forecast long-term government bond rate for the current year is subtracted from the following year's forecast value; the difference is then multiplied by a factor of 0.20 and the result is used to adjust the risk premium in the opposite direction. The adjusted risk premium is added to the forecast long-term bond rate to produce the rate of return on common equity for the following year. (This is mathematically equivalent to applying 80% of the change in long-term government bond yields to the previous year's ROE).

The formula is given by the following series of equations:

$$ROE_t = RP_t + LCBF_t$$

Where the current risk premium is given by:

$$RP_t = RP_{t-1} - 0.20 \times (LCBF_t - LCBF_{t-1})$$

[28] Regie de l'energie, Decision D-2009-156, December 7, 2009.

And the Long Canada Bond Forecast is given by the average forecast for the 10-year bond plus the average daily spread for the most recent month between the 30-year Government of Canada Bond and the 10-year Government of Canada Bond.

$$LCBF_t = \left[\frac{10\_CBF_{3,t} + 10\_CBF_{12,t}}{2}\right] + \sum_i \frac{30\_CB_{i,1} - 10\_CB_{i,1}}{i_t}$$

Vermont ROE Formula

The Vermont Public Service Board ("VPSB") has (under state law) permitted its utilities to adopt alternative regulation plans ("ARPs"), which have been developed and proposed by the utilities and their terms and have been negotiated and settled in Memorandums of Understanding ("MOUs") with the VPSB. Green Mountain Power has been operating under an Alternative Regulation Plan, which includes an AAM, since 2006. The Board approved a formulaic ROE and an adjustment factor that provides incentives for managing controllable costs as part of Green Mountain Power's ARP. The Formula adjusts ROE by 50% of the difference between the average ten-year Treasury note yield to maturity as of the last 20 trading days ending two weeks before the annual filing, and as of the 20 trading day period used for the last adjustment to the return on equity component. The ROE Performance Adjustment is intended to offer an opportunity to earn a higher ROE by exceeding the standard of excellence the Company had reached to date, when benchmarked against comparable utilities.[29] The incentive adjustment is limited to 50 basis points (upward or downward), and is allotted based on the quintile in which the company's peer group ranking falls.

The Green Mountain Power formula combines an earnings sharing mechanism with its formulaic ROE methodology that reflects the difference between the achieved versus authorized ROE for the preceding calendar year. The earnings sharing adjustor employs a 75 basis point deadband and a 50/50 sharing of earnings shortfalls between 75 and 125 basis points below the target return. There is no sharing of earnings above the targeted return.

The formula may be expressed as follows:

$$ROE_t = ROE_{t-1} + 0.50 \times \left[\sum_i \frac{10\_USB_{i,20}}{i_t} - \sum_i \frac{10\_USB_{i,20}}{i_{t-1}}\right]$$

Since the adoption of the formula by Green Mountain Power, Central Vermont Public Service has adopted the same formulaic methodology to adjusting ROE with the commencement of its Alternative Regulation Plan in 2008. Vermont Gas's formula remains fixed under their current Alternative Regulation Plan, which will be up for renewal in September 2011.

[29] State of Vermont, Public Service Board, *Petition of Green Mountain Power Corporation for Approval of an Alternative Regulation Plan (Plan II)*, Docket No. 7585, Order entered April 16, 2010, at 4.

California ROE Formula

A formulaic approach to adjusting ROE was implemented in 2008. The 2008 test year cost of capital applications were divided into two phases. The first phase established the applicable ROE for each of the utilities. The second phase led to the adoption of a cost of capital mechanism for the three major energy utilities. This mechanism is applied to each individual utility's established ROE from Phase I, and required the utilities to file cost of capital applications every third year, beginning with the 2011 test year. The principal features of the approach are:

- Establishes an interest rate benchmark (Moody's utility bond yield on date formula commences);
- The adjustment is based on 0.50 of the annual change in Moody's utility bond yields;
- There is a 200 basis point deadband, meaning that if interest rates change by less than 100 basis points from the benchmark interest rate, either up or down, the ROE remains unchanged;
- The interest rate benchmark is updated each time the formula exceeds the deadband and results in an adjustment to ROE; and
- A full ROE hearing is conducted every three years.

The California Commission looked favorably on the proposition that that the cost of capital formula would enable utilities, stakeholders, and the Commission to reduce and reallocate their respective workloads for litigating annual cost of capital proceedings. The formula may be expressed as follows:

$$if\ (Moodys\_Ut\_Bnd_t - \ Moodys\_UT\_Bnd_{benchmark}) > 100\ basis\ points, then$$

$$ROE_t = \ ROE_{t-1} + \ 0.50 \times (Moodys\_Ut\_Bnd_t - \ Moodys\_UT\_Bnd_{benchmark})$$

and

$$Moodys\_Ut\_Bnd_{new\ benchmark} = \ Moodys\_UT\_Bnd_t$$

Or

$$if\ (Moodys\_Ut\_Bnd_t - \ Moodys\_UT\_Bnd_{benchmark}) < 100\ basis\ points, then$$

$$ROE_t = \ ROE_{t-1}$$

The Commission selected a corporate utility bond index over U.S. Treasuries, reasoning that the latter is more sensitive to economic changes and risk in international capital markets than utility bonds because they are bought and sold globally, and found that U.S. utility bonds are generally less affected by major shifts in international capital. The Commission also found that a utility bond index would more closely correlate to a utility's risk than would a Treasury bond.

The Commission order cautions that "a deadband that is overly sensitive to interest rates causes needless volatility in revenues and rates. Conversely, a deadband that never triggers can impose unnecessary costs on shareholders or ratepayers, depending on which direction interest rates move." A deadband needs to strike a reasonable balance between triggering too often and not triggering often enough. The Commission found that a 100 basis point deadband over a 12-month average measurement period appropriately mitigated the volatility of interest rates.

The Commission decided in the absence of long term experience with this formula, that a shorter-term review period be established. As a result, and consistent with majority consensus, the Commission required a full cost of capital review on a triennial basis.

Mississippi ROE Formula

Mississippi's utilities operate under formula rate plans tailored to each utility. These rate plans incorporate a prescriptive approach to setting ROE based on specified weightings of common ROE methodologies: DCF, Risk Premium and CAPM. The prescriptive approach defines any areas of contention, such as proxy group selection criteria and data inputs, and though complicated and comprehensive, results in an ROE analysis without litigation or contention. The Commission in effect has reached agreement with the utilities and stakeholders as to methodological approach and sources of inputs necessary to arrive at a reasonable estimate of ROE. The inputs are agreed upon and specified, such as growth rates, betas, etc., as are any adjustments to ROE for flotation costs and performance incentives, and are used annually to adjust ROE.

In simple terms, a benchmark ROE is calculated each year based upon the prescribed methodologies and inputs. The benchmark ROE is further adjusted by a performance factor, to arrive at the annual performance-adjusted benchmark. If the resulting performance-adjusted benchmark ROE yields an authorized return that differs from the calculation of the expected return (detailed below) by greater than a specified deadband, revenues are either increased or decreased to make up for the shortfall or overage in expected returns. The authorized revenue increase for annual rate increases is subject to a 4% revenue cap. For some utilities, the revenue cap acts as a hard cap (or ceiling) and for others it may signal the need for an ROE proceeding (a trigger mechanism).

Below is a summarization of the approach used to develop Atmos Energy's performance adjusted ROE benchmark in accordance with its rate stabilization rider. Atmos Energy is a Mississippi gas utility and the methodologies prescribed in its rate stabilization rider are generally characteristic of those applied to other Mississippi utilities.

The first step is calculating the Expected Equity Return given by the following formula:

$$\left(\frac{Test\ Year\ Revenues - Test\ Year\ Expenses - Adjs.for\ Known\ \&\ Measureable\ Differences}{Average\ Rate\ Base\ Equity}\right)$$

The performance adjusted ROE benchmark is given by the following formula:

$$PA\_ROE_{bench} = \frac{DCF + Regression\ Analysis + CAPM}{3} \mp PA$$

The methodologies are prescribed as follows:

Proxy group screening criteria for parent companies of operating utilities:

- Gas Distribution Utilities listed by the Value Line Investment Survey
- Must have annual operating revenues not less than one-half nor more than twice those of Atmos Energy Corporation. If this results in less than 10 sample companies, such group shall be represented by the ten companies in the Value Line Survey list having the closest annual revenues to Atmos Energy Corporation.
- Must have each of the following earnings growth rates: Value Line, Zacks, I/B/E/S.
- Must have Value Line beta
- Must pay dividends and have a positive dividend growth rate
- Atmos Energy must be excluded from the Group

DCF Approach

$$k = \frac{D_1}{P_0} + g$$

- Expected dividend yield is calculated by increasing the current dividend by the applicable growth rate (g) at the normal dividend change timing pattern as stated in Value Line.
- Stock prices are the average daily closing stock prices from Yahoo Finance for the one month prior to the determination of the ROE.
- Earnings growth rates are the average of the projected earnings growth rate for each of the comparable companies in Value Line, I/B/E/S Thomson Financial, and Zack's.
- The DCF model is performed for each comparable company, and the truncated mean is used, which is derived by discarding the highest and lowest DCF results.

The Regression Analysis Approach

$$Y = a + b\ (x)$$

- "Y" represents the average return on common equity capital allowed in all gas rate cases by state regulatory commissions as reported by RRA for a given calendar year.
- The independent variable "X" represents Moody's average annual A-rated public utility bond seasoned for the year corresponding to the allowed return on equity.
- The model uses 15 years of historical monthly data.
- $Y_{current}$ is solved by applying the resulting regression coefficients "a" and "b" to the average monthly Moody's A-rated utility bond yields "x" for the most recent calendar quarter.

CAPM Approach

$$CAPM = R_f + \beta\ (RP)$$

- Risk-free rate is the simple average of the last three monthly averages of yield on 20-year Treasury bonds as reported by Federal Reserve Statistical Release H.15(519).
- Beta is the average of the betas (adjusted) as stated in Value Line for the same group of comparable utilities in the DCF analysis.
- The Risk Premium is the difference between the arithmetic average annual return on Common Stock (Total Return Index) and in Long-term Government Bonds (Total Return Index) found in the Ibbotson Associated Yearbook from 1926 through most recent data.

Performance adjustments ranging from positive to negative 50 basis points are added to the benchmark ROE to arrive at the performance adjustment benchmark ROE. The performance adjustments vary among utilities in Mississippi, but in the case of Atmos Mississippi, the performance adjustment is based on the weighting of a price benchmark study (weighted 75%) and a customer satisfaction survey (weighted 25%).

To determine the actual revenue increase or decrease, an example of the calculation, which assumes a rate base of $50 million and an equity ratio of 40%, or an equity rate base of $20 million and annual revenues of $10 million is as follows:

Expected Equity Return	8.00
Less: Performance-Adjusted Benchmark ROE	11.50
Difference	(3.50)
Absolute Value of Difference > 100 basis point deadband?	YES
Allowed Adjustment to Rates	3.50
Multiplied by: Equity Rate Base	20,000,000
Δ in Equity Revenue to Achieve Rate Base Required Return	700,000
Divide by: (1-Tax) for tax expansion	.65
Total Revenue Change Required	1,076,923
Actual Gross Revenue for Test Period	10,000,000
Apply 4% Cap to Actual Gross Revenues	400,000
Rate Adjustment = MIN(Revenue Change Required or 4% Revenue Cap)	400,000

The Mississippi Commission has attributed the following benefits to the adoption of its formula rate plan:

- A systematic process that essentially stabilizes earnings, while allowing the utility a reasonable opportunity, with efficient operation, to achieve its allowed return with neither on-going excess earnings nor ongoing under-earnings;
- Rates can be adjusted based on performance and/or service quality;
- More systematic and frequent reviews of utility books and records which results in a utility's earnings and services being more closely monitored by its regulators;
- Stability of rates;
- A significant savings in time, resources, and costs that are generally related to traditional rate case filings; and
- Higher credit rating.

c. Backcast Review of Alternative Formulae Performance

In an effort to evaluate the performance of the alternative methodologies relative to one another and to non-formulaic allowed returns, Concentric benchmarked the formulas in a backcast analysis that commences in 1994, the beginning of the BC formulaic adjustment approach. Each formula (with the closest proxy for inputs) is modeled to mimic its hypothetical performance over the past 16-year period. In this analysis, we begin with a starting point of 10.75% in 1994, the actual starting point for Terasen's (then BC Gas) ROE awards under the formula. To promote comparability across formulas and to eliminate variability due to timing alone, we have adjusted each formula annually based on a March 31st closing value for all inputs (except as noted) regardless of the adjustment time frames prescribed by each of the respective Commissions. In cases where the formulas relied upon forecast inputs, such as forecasted bond yields, we have backcast the actual bond yields for the given bond in our analysis. Because the backcast analysis establishes each formula beginning in 1994 at 10.75%, and updates each formula in the first quarter of the year, which differs from the actual timing in which the formulae are set and updated, and because we have used actual historical inputs as a proxy for forecast formula inputs, there are differences between the formula results we have generated in our backcast analysis and the actual ROE results for each respective formula's historical ROE application. This method allows for a comparison of each formula on an apples-to-apples basis.

The alternatives considered in our backcast analysis are those unique formulas identified through our research both in Canada and the U.S.: (i) the newly adopted Ontario formula; (ii) the Quebec (former BC, Ontario and NEB) formula; (iii) the Newfoundland and Labrador formula; (iv) the Vermont formula; (v) the California formula (with a 100 basis point deadband); (vi) the California formula (excluding the deadband); and (vii) the Mississippi formula (as it has been applied to its natural gas utility ATMOS). In addition, we have modeled a formula that is tied entirely to an index of U.S. utility authorized return data generated by Regulatory Research Associates ("RRA")[30] to facilitate comparison to the average U.S. litigated authorized returns over the same period. Concentric had also developed a formula which weights U.S. authorized returns equally with a corporate bond yield adjustment mechanism (using a 50% adjustment factor). Concentric recommended this formula in Alberta and Ontario to recognize the importance of litigated North American authorized returns for ROE determinations in Canada, and the integration of capital markets and similarity of regulatory models and corresponding risks for utilities in the two countries. Lastly, we have included Terasen Gas Inc.'s actual allowed returns for comparison purposes. The details of how each formula is modeled in our backcast analysis are described more fully in Table 2.

[30] A comprehensive data base of regulated utility sector data (including summary data and ranking of all U.S. utility commissions) and utility-specific regulatory data. RRA is owned by SNL Financial which collects, standardizes and disseminates all relevant corporate, financial, market, and M&A data, as well as news and analysis for the Banking, Financial Services, Insurance, Real Estate, Energy and Media & Communications industries.

Table 2: Description of Formulas in Backcast Analysis

Backcast Modeling Description	Technical Attributes
Ontario Formula-based Return on Equity (gray line) **$ROE_n = ROE_{n-1} + 0.50 \times (\text{Gov Can 30-year}_n - \text{Gov Can 30-year}_{n-1}) + 0.50 \times [(\text{Can Util Bond}_n - \text{Gov Can 30-year}_n) - (\text{Can Util Bond}_{n-1} - \text{Gov Can 30-year}_{n-1})]$**	o Gov Can 30-year equals Government of Canada 30-year bond yield o Can Util Bond equals Bloomberg Fair Value 30-year Canada A-rated Utility bond index
Québec (former BC/Ontario/NEB) Formula-based Return on Equity as it has been most recently applied (orange line) **$ROE_n = ROE_{n-1} + 0.75 \times (\text{Gov Can 30-year}_n - \text{Gov Can 30-year}_{n-1})$**	o Gov Can 30-year equals Government of Canada 30-year bond yield o The formula, as prescribed by the Régie (and formerly BC, Ontario, and the NEB), depends on forecasts of long-term Government of Canada bond yields. In order to express the formula on an apples-to-apples basis with others, actual bond yields were used.
Newfoundland and Labrador Automatic Adjustment Mechanism (blue dotted line) **$ROE_n = \text{Gov Can 30-year}_n + ((ROE_{n-1} - \text{Gov Can 30-year}_{n-1}) - 0.20 \times (\text{Gov Can 30-year}_n - \text{Gov Can 30-year}_{n-1}))$**	o Gov Can 30-year equals Government of Canada 30-year bond yield o The formula, as amended by the PUB, depends on forecasts of long-term Government of Canada bond yields. In order to express the Newfoundland and Labrador formula on an apples-to-apples basis with others, actual bond yields were used.
Vermont ROE Adjustment Mechanism (purple line) **$ROE_n = ROE_{n-1} + 0.50 \times (\text{US 10-year Treas}_n - \text{US 10-year Treas}_{n-1})$**	o US 10-year Treas. equal to U.S. Government 10-year Treasury bond yield
California Cost of Capital Mechanism (red line) **$ROE_n = ROE_{n-1} + 0.50 \times (\text{Moody's Baa}_n - \text{Moody's Baa benchmark})$ where $(\text{Moody's Baa}_n - \text{Moody's Baa benchmark})$ must be greater than 100 basis points (1.00%)**	o Moody's Baa equals Moody's Baa-rated Utility Bond Index o Moody's Baa benchmark initially equal to March 31, 1994 closing value, reset to any value of the Moody's index that triggers the cost of capital mechanism (year-over-year change greater than 100 basis points)
California Cost of Capital Mechanism without dead band (red dotted line) **$ROE_n = ROE_{n-1} + 0.50 \times (\text{Moody's Baa}_n - \text{Moody's Baa benchmark})$**	o Moody's Baa equals Moody's Baa-rated Utility Bond Index o Moody's Baa benchmark initially equal to March 31, 1994 closing value.
Atmos Energy Corp. – Mississippi (green line) **Actual results of "calculation of benchmark return on rate base equity" for 2002 through 2009, calculated each year by Atmos based on a prescriptive formula**	o Formula is the average of a Discounted Cash Flow Analysis, Capital Asset Pricing Model, and Risk Premium Regression Analysis o A backcast of this formula is not feasible due to data constraints but historical results of the formula are presented.
U.S. Weighted-Average Authorized ROE Index (thick black line) **$ROE_n = ROE_{n-1} \times \text{US\_ROE\_Index}_n$**	o *US ROE Index* equal to weighted-average authorized ROE for U.S. electric and natural gas utilities provided by Regulatory Research Associates ▪ Average for each quarter weighted by number of cases ▪ Index equal to $\text{Year}_n\text{Q1} / \text{Year}_{n-1}\text{Q1}$
Concentric Alberta/Ontario Recommendation (blue line) **$ROE_n = \text{Average}(ROE_{n-1} + 0.50 \times (\text{Can Util Bond}_n - \text{Can Util Bond}_{n-1}), ROE_{n-1} \times \text{US ROE Index}_n)$**	o Can Util. Bond equals Bloomberg Fair Value 30-year Canada A-rated Utility bond index ▪ Index did not start until 3/5/2002, quarterly data prior to that provided by Canadian Bond Rating Service
Terasen Gas Inc. Actual Authorized ROE (black dotted line)	o BCUC allowed ROE for BC Gas Utility Ltd. and Terasen Gas Inc. as reported in annual reports

If we were to use the BCUC litigated ROE proceedings beginning with a 10.75% ROE, authorized by the Commission in 1994, and a 9.5% ROE, authorized by the Commission in 2009 as data points to indicate the desired formulaic path over the period, in Figure 4, we observe that formulae with a lower sensitivity to changes in bond yields, i.e. the California, Ontario and Vermont formulae or the Concentric recommended weighted formula (50% regression formula and 50% index of average North American litigated returns) have generated the formulaic path that best connects the BCUC's decisions at each end of that 16-year period.

It is interesting to note that the coefficient that would have been necessary under the former BC ROE adjustment formula to link the ROE set by the Commission in 1994 of 10.75%[31] to the ROE set in 2009 of 9.5%[32], as a function of 30-year government bond yields, all else being equal, would have been 0.34 (or each one percent change in the 30-year government bond yield would effect a 0.34 percent change in the allowed return), much lower than the BC formula coefficient at any time during the history of the formula, and closer to the historical relationship between government bond yields and U.S. regulated authorized returns represented in Table 1, of 0.29 to 0.43.

Conversely, formulae that are highly sensitive to changes in bond yields (Newfoundland and Labrador with a coefficient that effectively has 0.80 sensitivity to changes in government bond yields) and the Quebec (former BC/Ontario/NEB) formula (with a 0.75 sensitivity to changes in government bond yields) have generated progressively lower ROEs over the 16-year period than actual litigated returns in either BC or the U.S. Our research has shown that this is due to the formulas' sensitivity to the sustained decline in interest rates, which has characterized government bond yields over the period. These effects are illuminated by comparing the results of those formulae to the Vermont formula, also based on government bond yields, but with reduced sensitivity of 0.50 (applied to the 10-year U.S. Treasury bond yield). As we may observe in Figure 4, the lesser sensitivity to changes in government bond yields in the Vermont formula results in formulaic outcomes that are much more in line with litigated ROEs over the period and accordingly results in a more moderate response to volatility in government bond yields. We observe that the California formula, with a sensitivity of 0.50 to changes in corporate utility bond yields, also yields a moderate ROE result on par with ROEs determined in litigated rate hearings and only slightly higher than the results of the Vermont formula (based on government bond yields).

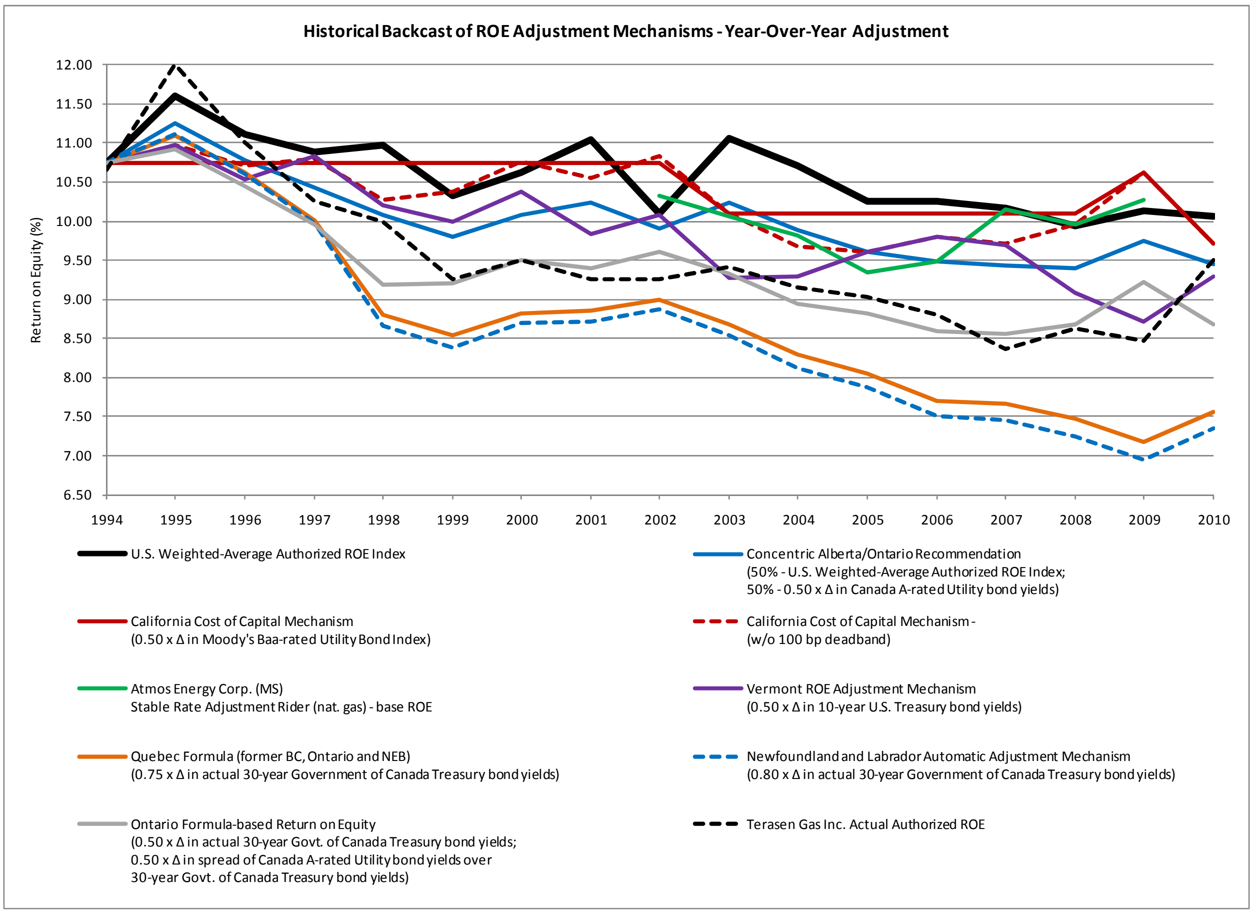
Because of the abundance of regulated utilities in the U.S. and the number of litigated returns that arise out of the regulatory process in 50 state regulatory jurisdictions, the U.S. provides an excellent source for North American utility equity return data. Though we would not expect the average U.S. utility return to necessarily be identical to a return issued for a given Canadian utility (although it is possible to select a proxy group of U.S. companies that would be comparable to a Canadian utility), directionally we would expect average returns in the two countries to move in tandem. To that end, we have developed an index, which divides the current year weighted average U.S. ROE decisions by the base year average and applies that index on a year over year basis to the litigated BCUC decision in

31 BCUC Decision No. G-35-94, June 10, 1994.
32 BCUC Decision No. G-158-09, December 16, 2009.

1994 of 10.75%, to develop a directional benchmark for BCUC ROE that would parallel the changes in U.S. litigated returns.

As illustrated in Figure 4, formulae that are moderately sensitive (0.50 coefficient) to corporate utility bond yields (California or Ontario formula), or government bond yields (the Vermont formula), or calculations of the equity returns such as a prescriptive ROE approach (Mississippi formula) or a formula that tracks U.S. litigated equity returns (the RRA Index) as recommended by Concentric in Alberta and Ontario (50% regression formula and 50% index of average North American litigated returns), provide results most comparable to the directional U.S. litigated returns benchmark.

Figure 4: Backcast Analysis



d. Relative Performance Across Varying Economic and Market Conditions

To better understand how each of the formulas would perform across varied economic and market conditions, we developed a stress test analysis, to identify the formulaic approaches that were more subject to the volatility of inputs and accordingly more prone to instability or outlier results. Concentric conducted this test by varying each of the formulas' inputs by 2 standard deviations above and below its current value to approximate a sustained increase or decrease in the value of the input.[33] For each input, we computed the standard deviation of daily closing values between January 1, 1994 and June 30, 2010. We then ratably grew each input, over a 10-year period, so that by the end of the tenth year, each input variable would be exactly two standard deviations greater than its original value and conversely, two standard deviations less than its original value. We calculated and graphed how each of the formulae would perform under those circumstances in each year of our test period (heavy solid line). Additionally, we computed what the ROE result of each formula would be if long-term forecasts (Consensus Forecasts and Blue Chip) were to be realized. We have plotted this ROE result on the graphs that follow (heavy dashed line) to indicate the formulaic ROE that would be produced by the current long-term forecasts of certain formula inputs.[34]

The general statistics we calculated for each formula input are summarized in Table 3. For each primary input, i.e. U.S. ROE decisions, Bloomberg A-Rated Utility Bonds, Moody's Baa-Rated Utility Bonds, U.S. 10-Year Treasury Bond, and Government of Canada 30-Year Long Bonds, we generated the mean, median, standard deviation, sample variance, range, minimum, and the number of observations for the sample.

33 Daily closing value as of June 30, 2010 except for 'U.S. ROE Decisions' which is a quarterly weighted average

34 Long-term forecasts are not available for the following variables: U.S. ROE Decisions, Moody's Baa-rated Utility Bond Index, Government of Canada 30-year bonds, and Bloomberg Canada A-rated Utility Bond Index. For the Moody's Baa-rated Utility Bond Index, we estimated the spread between the Moody's Index and U.S. Government 30-year Treasury bonds using linear regression (using daily data from 1/1/1994 – 6/30/2010). The resulting linear equation was applied to the Blue Chip forecast of U.S. Government 30-year Treasury bonds to arrive at a forecast estimate of Moody's Baa-rated Utility Bond Indices. For Government of Canada 30-year bonds, we took a similar approach and estimated the spread between 10- and 30-year bonds using linear regression (using daily data from 1/1/1994 – 6/30/2010), which was applied to the Consensus Forecast of Canada 10-year Treasury bonds to arrive at an estimate of the Forecast for the 30-year Government of Canada Bond Yield. Lastly, For the Bloomberg Canada A-rated Utility Bond Index, we estimated the spread between the Bloomberg Index 30-year A-rated Utility Index and the Government of Canada 30-year bonds using linear regression (using daily data since the inception of the Bloomberg index from 3/5/2002 – 6/30/2010), which was applied to the derived forecast of Canada 30-year government bond yields to arrive at a forecast for the 30-year Canadian A-rated Utility Bond Yield.

Table 3: Descriptive Statistics of Formula Inputs

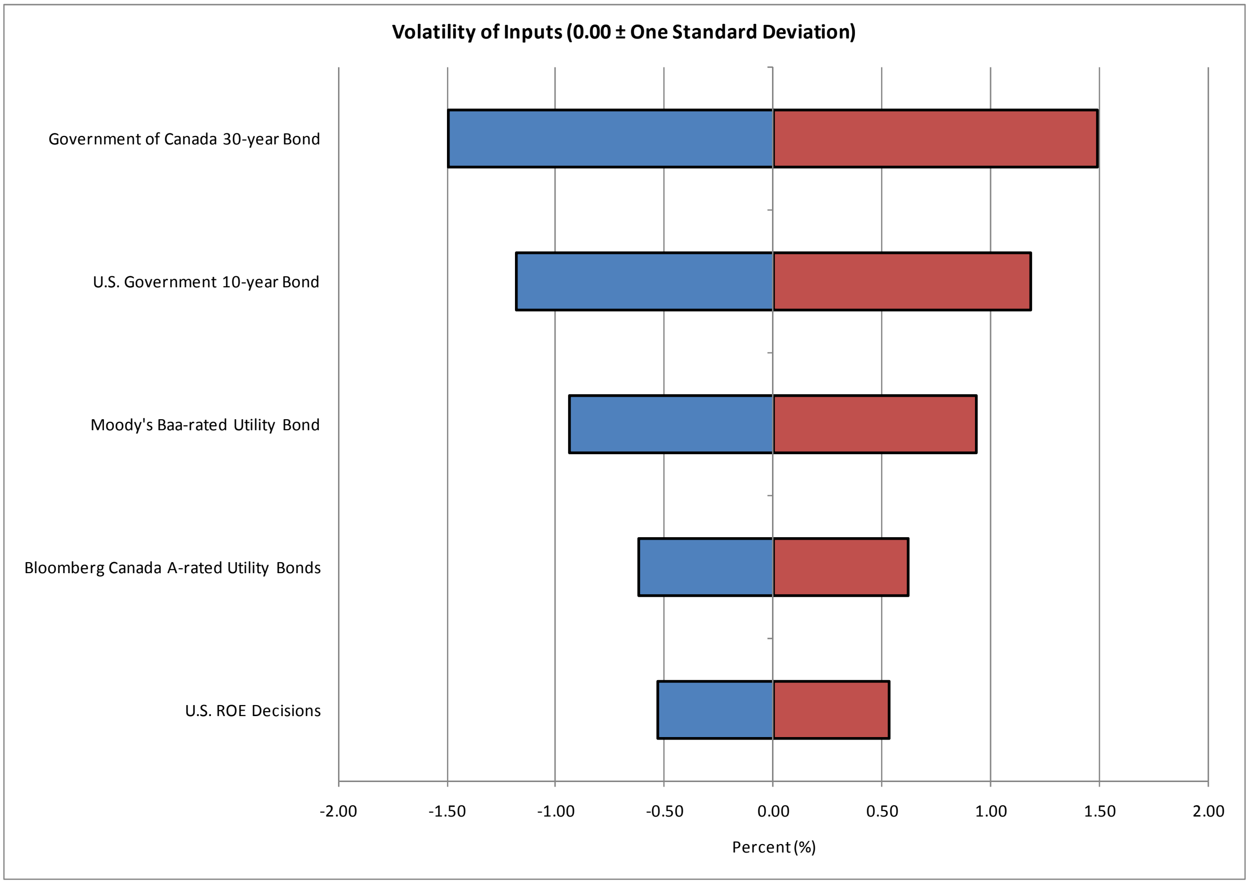
DESCRIPTIVE STATISTICS (January 1, 1994 - June 30, 2010)

	[A] U.S. ROE Decisions	[B] Bloomberg Canada A-rated Utility Bond	[C] Moody's Baa-rated Utility Bond	[D] U.S. Government 10-year Bond	[E] Government of Canada 30-year Bond
Mean	10.91	5.81	7.38	5.08	5.65
Median	10.94	5.61	7.54	4.90	5.49
Standard Deviation	0.53	0.62	0.94	1.18	1.49
Sample Variance	0.28	0.38	0.87	1.40	2.23
Range	2.23	2.35	3.87	5.97	6.30
Minimum	10.03	4.86	5.58	2.08	3.39
Maximum	12.26	7.21	9.45	8.05	9.69
Count	66	2,172	4,118	4,129	4,278

Notes:
[A] Source: Regulatory Research Associates; quarterly weighted-average authorized ROE for electric and natural gas distribution companies
[B] Source: Bloomberg Professional; daily data available beginning 3/5/2002
[C] Source: Bloomberg Professional; daily data
[D] Source: Bloomberg Professional; daily data
[E] Source: Bloomberg Professional; daily data

In the statistics above, we can see that the variability of government bond yields, as measured by the standard deviation and the sample variance are much greater than the variability in U.S. ROE decisions or corporate utility bond yields. They also possess the largest percentage point range between the high yield and the low yield of all the samples (5.97 and 6.30 percentage points for the U.S. 10-year bond and the Canadian 30-year bond, respectively). The variability in U.S. ROE decisions is the lowest within the sample of formula inputs with a total range between the high and low ROE percentage of 2.23 percentage points. This is further illustrated in Figure 5, which shows the standard deviation of each input.

Figure 5: Standard Deviation of Formula Inputs

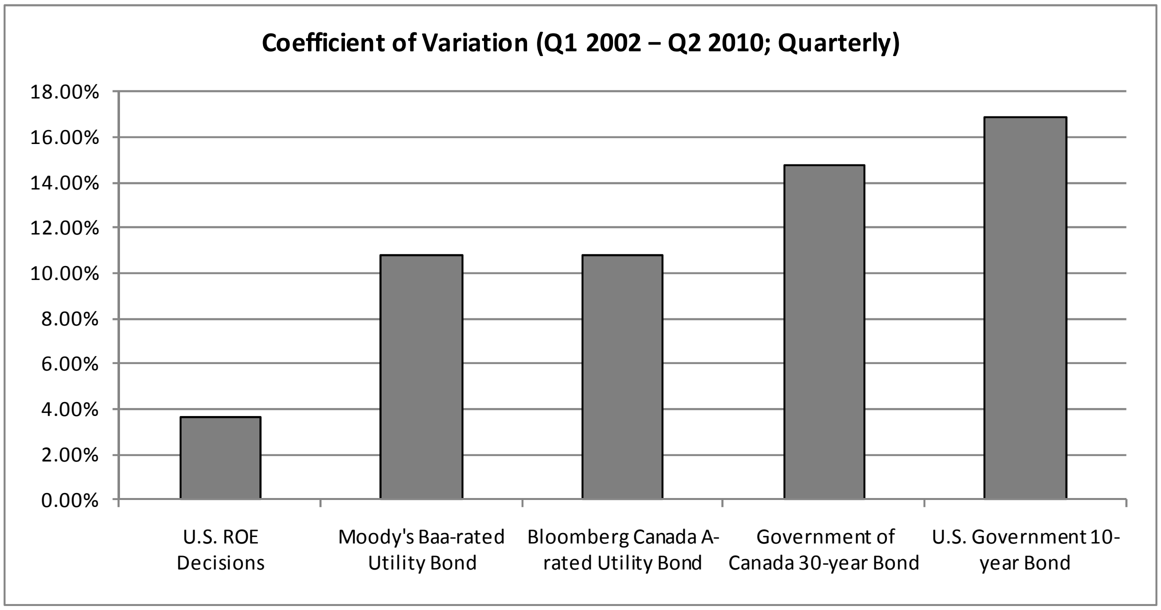


We have further standardized the above volatility measures by dividing by the mean of each of the respective inputs to find the coefficient of variation ("COV"), or the standard deviation relative to the mean, for comparison across all of the inputs. This is a useful way to compare the degree of variation across these inputs, even though their means vary. The lower the COV, the lower the variability in relation to its mean value, implying greater stability in a formula employing this input. Again, we observe that government bond yields are the most volatile of the inputs generally relied upon for ROE adjustment mechanisms[35] and U.S. litigated authorized returns are the least variable.

[35] Notes:

1. 'Coefficient of Variation' equals Standard Deviation / Mean.
2. Time period (Q1 2002 – Q2 2010) dictated by 'Bloomberg Canada A-rated Utility Bonds' which became available March 5, 2002.
3. Quarterly data used for all inputs because 'U.S. ROE Decisions' are only available quarterly. The remaining inputs are available daily, weekly, monthly, quarterly, and annually.

Figure 6: Standardized Volatility of Formula Inputs – Coefficient of Variation

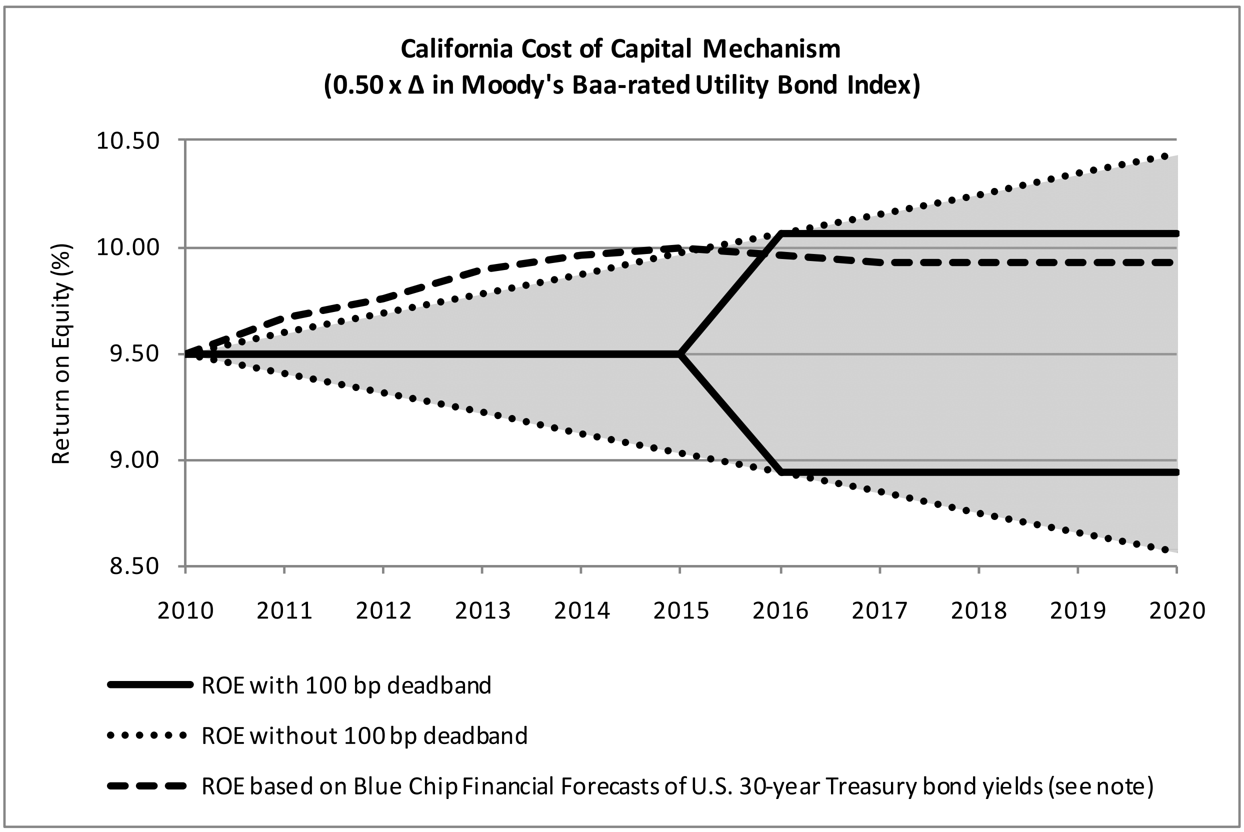


Note: Time period (Q1 2002 – Q2 2010) dictated by Bloomberg Canada A-rated Utility Bond Index which commenced on 3/5/2002.

<u>Results of Stress Test - California</u>

From the 9.5% ROE currently in effect for Terasen today, the shaded area in Figure 7 represents the results of our stress test on the projected inputs in the California ROE adjustment formula. The Moody's Corporate Baa utility bond standard deviation is 0.94. The solid lines below represent the ROE results at each point of the stress test, when employing the 100 basis point deadband; while the fine dotted lines reflect the results of the formula under stress with no deadband. The heavy dotted line represents the ROEs that would result from the long term forecast for these inputs, according to Blue Chip Consensus Economic Forecast. That graph reflects that forecasted corporate bond yields are currently projected to increase by more than that provided by our stress test (1 standard deviation in 5 years; 2 standard deviations in 10 years), hence the forecast falls outside the shaded range in the early and middle years. The Blue Chip Economic Forecast projects that 30-year U.S. Treasury Bond is forecast to grow from 4.5% in 2010 to a high of 6.0% in 2015 and settle at 5.8% towards the end of the ten-year period.

Figure 7: California Cost of Capital Mechanism Stress Test Range and Forecasted Results



Note: Historical relationship between U.S. 30-year Treasury bond yields and Moody's Baa-rated Utility Bond Index estimated by linear regression and applied to forecasts of U.S. 30-year Treasury bond yields.

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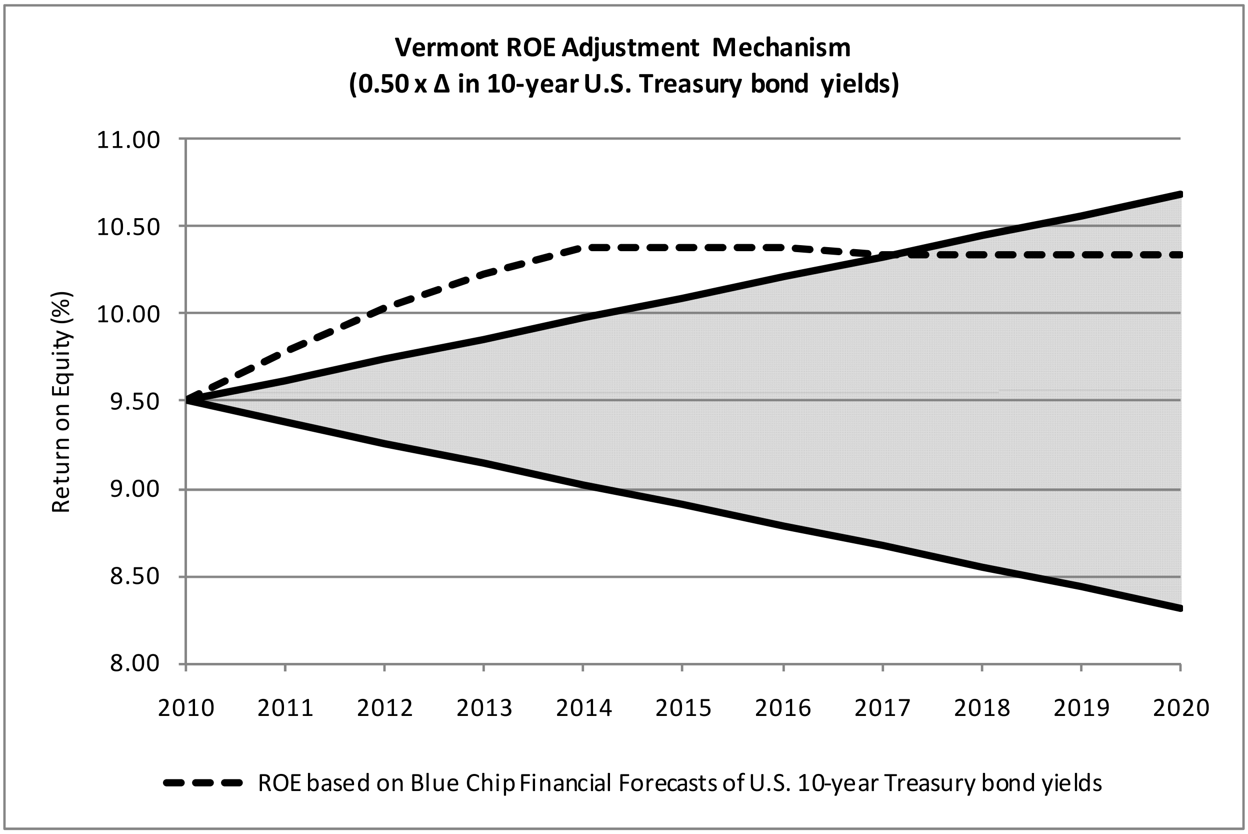
Results of Stress Test - Vermont

As indicated in Table 3, the standard deviation for the 10-year U.S. government bond yield is 1.18. The solid lines in Figure 8 show the impact of an increase/decrease in the starting bond yield equal to two standard deviations (2.36%) over 10 years. Figure 8 also shows (dotted line) a rapid increase in forecasted government bond yields that cause the projected results to fall outside the shaded range during the early and middle years. Blue Chip Consensus estimates for 10-year U.S. Treasuries climb to a high of 5.5 percent by 2014, from a current value of 2.97 percent as of the end of the second quarter in 2010, settling at 5.4 percent from 2017 through 2020.[36]

Figure 8: Vermont Cost of Capital Mechanism Stress Test Range and Forecasted Results

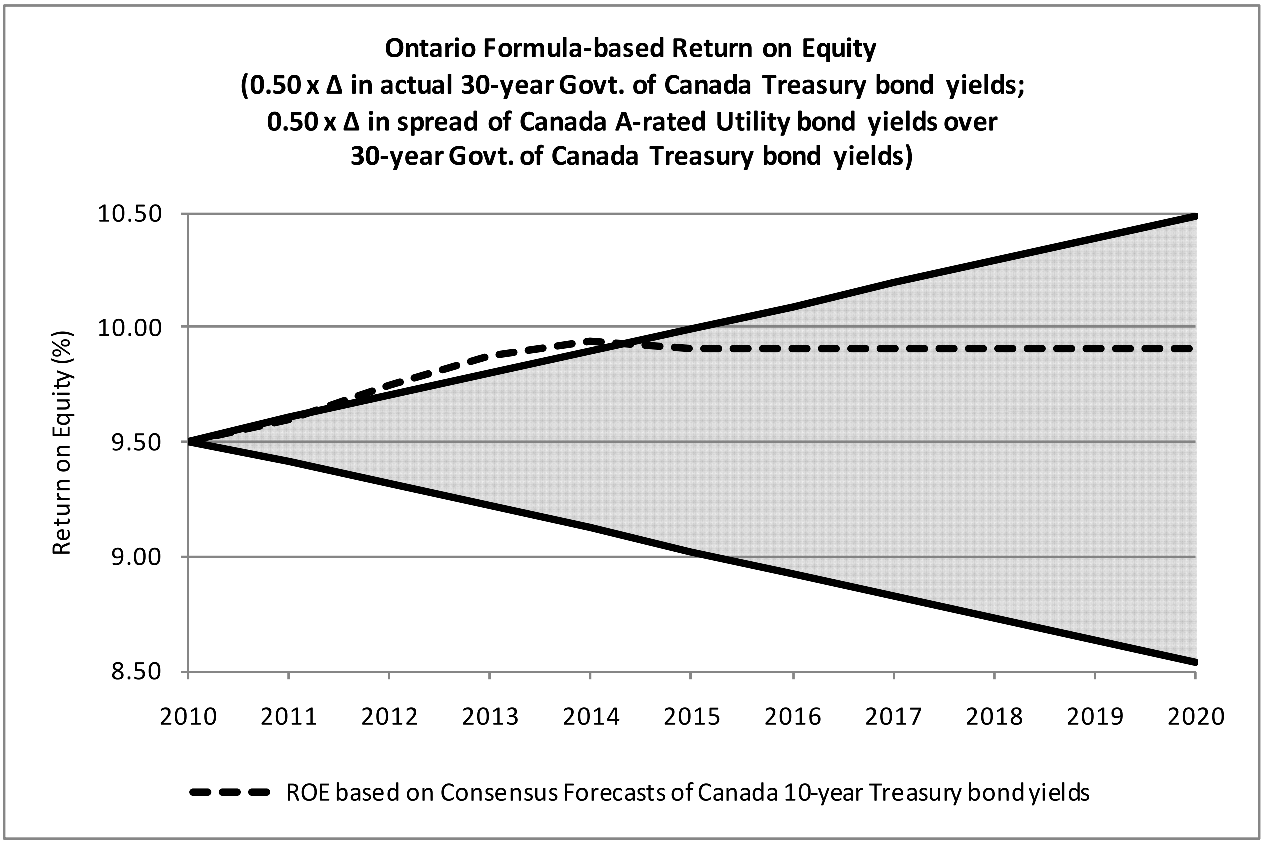


36 Blue Chip Financial Forecasts, Vol. 29, No. 6, June 1, 2010.

Results of Stress Test - Ontario

The current Ontario formula is diagrammed in Figure 9, under stress parameters of 2 x the standard deviation of 1.49 for the 30-year Government of Canada Bond yield, which serves as a basis for the formula. Our forecast projection (dotted line) and stress test (solid lines) are based upon the Consensus Economics long term 10-year long bond forecast (projected to increase from 3.8% in 2010 to 5.1% in 2020)[37], plus our estimate of the projected spread between Canada 10-year bonds and Canada 30-year long bonds determined using regression analysis and the following equation ($Spread_{10,30}$ = 0.4889 - 0.0299(Canada 10-year bond)). To that derived 30-year government of Canada bond yield projection, we estimated the projected spread between Canada 30-year long bonds and 30-year Bloomberg A-rated utility bonds using the following linear regression equation: ($Spread_{30,Util30}$ = 2.8297 - 0.3481(Canada 30-year bond)).

Figure 9: Ontario Cost of Capital Mechanism Stress Test Range and Forecasted Results



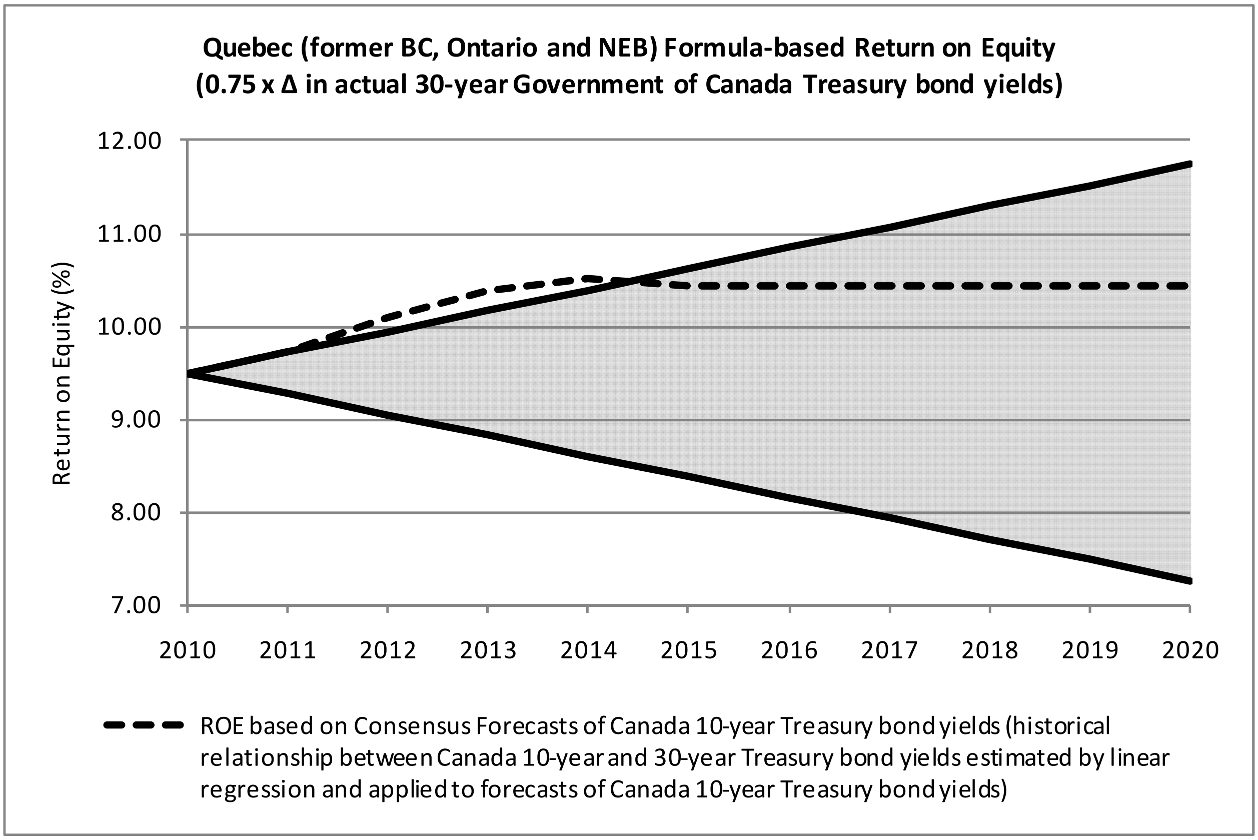
Note: Historical relationship between Canada 10-year and 30-year Treasury bond yields and Canada 30-year Treasury and Canada 30-year A-rated utility bond yields estimated by linear regression and applied to forecasts of Canada 10-year Treasury bond yields.

[37] April 2010 long term Consensus Forecast for Canadian 10-Year Treasury Bonds

Results of Stress Test –Quebec (former BC, Ontario and NEB formula)

Similarly, we modeled the former BC formula under stress parameters of 2 x the standard deviation of 1.49 for the 30-year Government of Canada Bond. Our projection and stress test is based on the Consensus Economics long term 10-year long bond forecast (projected to increase from 3.8% in 2010 to 5.1% in 2020)[38] plus the estimated spread between Canada 10-year bonds and Canada 30-year long bonds determined by the linear regression analysis ($Spread_{10,30}$ = 0.4889 - 0.0299(Canada 10-year bond).

Figure 10: Quebec (former BC, Ontario and NEB) Cost of Capital Mechanism Stress Test Range and Forecasted Results

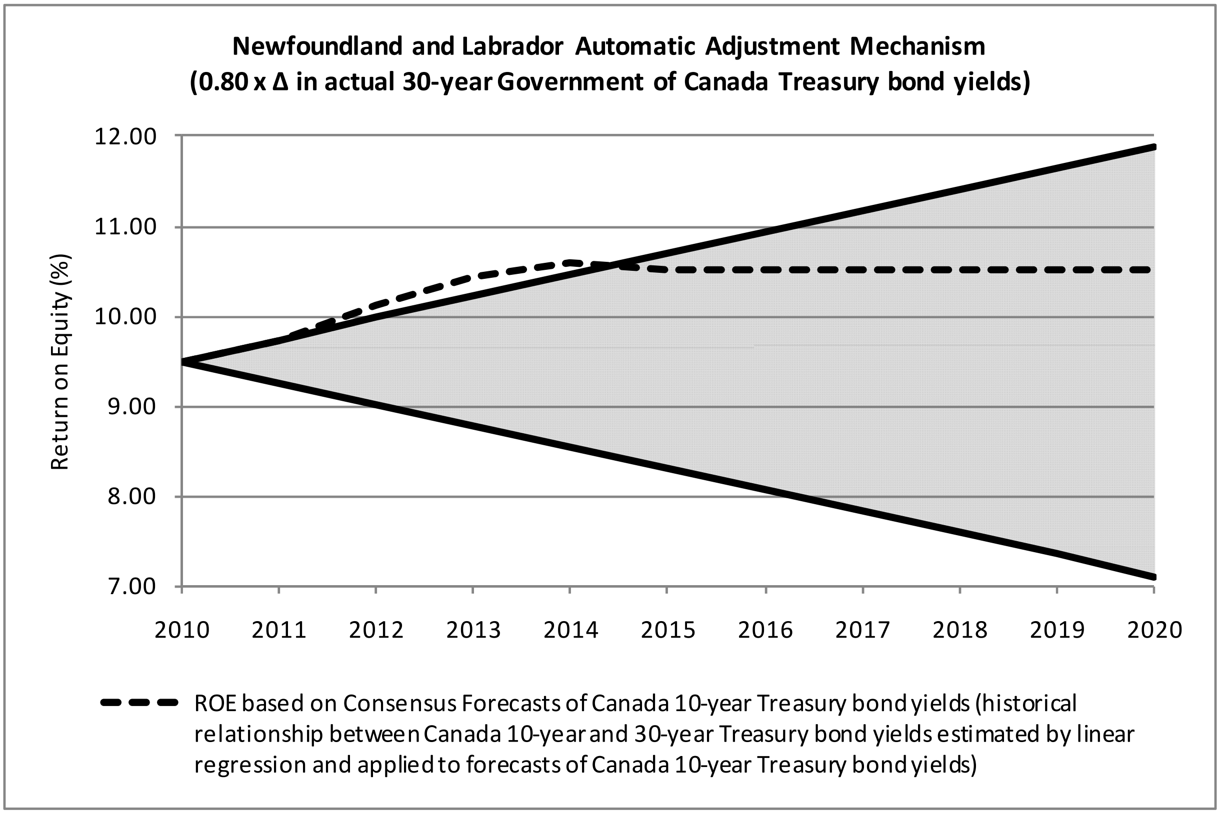


[38] Ibid.

Results of Stress Test – Newfoundland and Labrador

Similarly, we modeled the Newfoundland and Labrador formula under stress parameters of 2 x the standard deviation of 1.18 for the 10-year Government of Canada Bond. Our projection and stress test is based on the Consensus Economics long term 10-year long bond forecast (projected to increase from 3.8% in 2010 to 5.1% in 2020)[39] plus the estimated spread between Canada 10-year bonds and Canada 30-year long bonds determined by the following linear regression equation: ($Spread_{10,30}$ = 0.4889 - 0.0299(Canada 10-year bond)). Those results are presented in Figure 11.

Figure 11: Newfoundland and Labrador Cost of Capital Mechanism Stress Test Range and Forecasted Results



Stress Test Summary

The range of formula outcomes from applying the stress test of two standard deviations is pictured in Figure 12 for each of the formulas reviewed. We have found that a formula based on utility bond yields with a 50% adjustment factor (as is the case in California, Ontario, Vermont and that proposed by Concentric in the OEB and Alberta ROE proceedings which employed an equal weighting of the movement of the RRA index with an adjustment formula based upon Canadian utility bond yields, with a 50% adjustment factor) display the least variation in predicted outcomes based on historic volatility. The current Ontario formula introduces slightly greater volatility as a result of its reliance on the government bond yield to which the spread between the government bond yield and the Bloomberg Canadian A-Rated utility bond yield is added. Those formulae with a high sensitivity to government bond yields display the greatest range of outcomes, and also the most rapid increases in ROEs based on forecast increases in government bond yields (denoted by the heavy dashed lines in each preceding chart).

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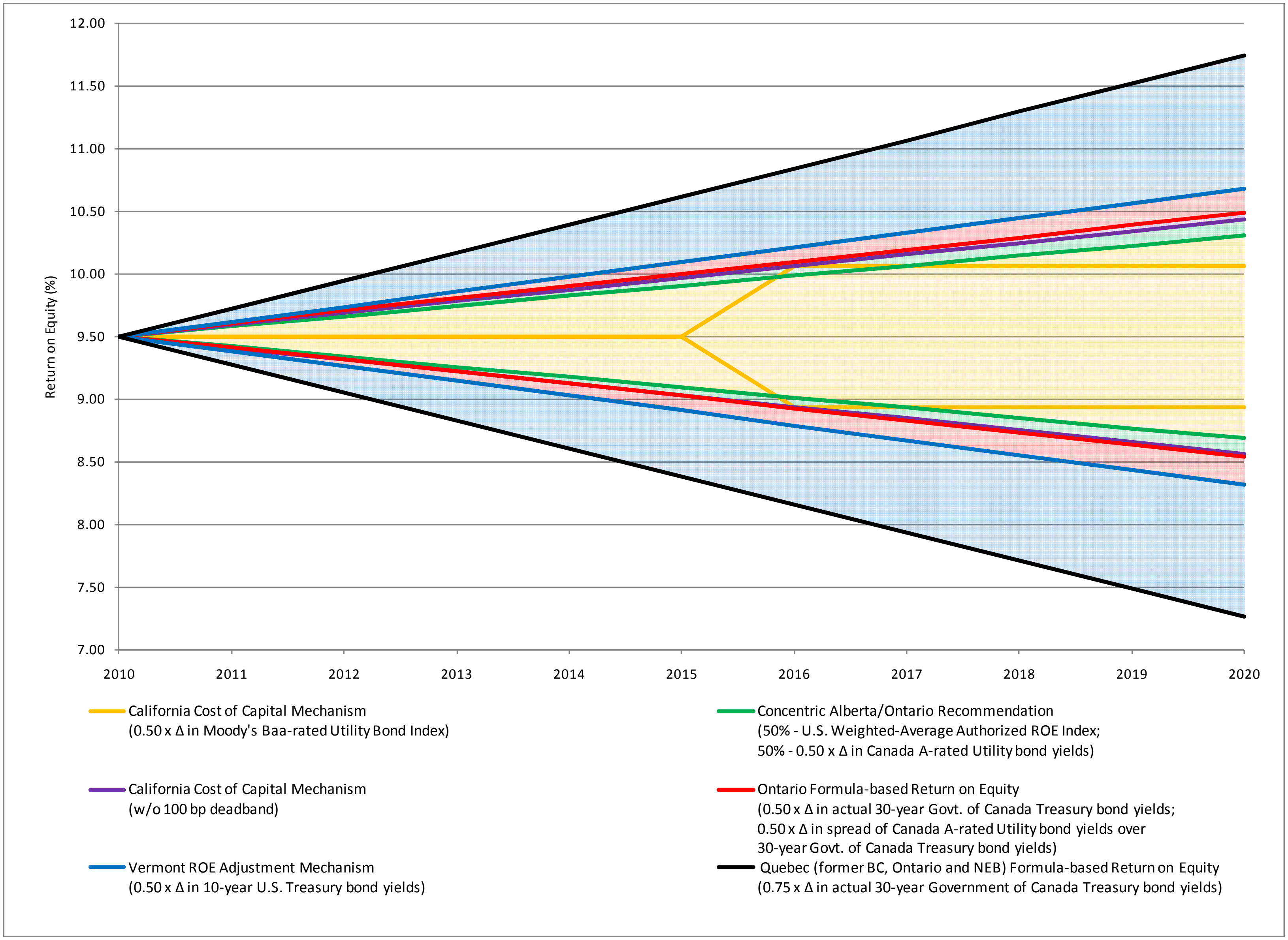
[39] Ibid.

Figure 12: Stress Test Range of ROE Outcomes for all Formulae



e. Transparency and Data Availability

Regulatory transparency refers to the general understanding of the ROE setting process and the predictability of outcomes. This is an advantage of the formulaic approach to determining ROE over the litigated ROE process where regulatory outcomes are difficult to predict. A formulaic ROE that can be estimated by stakeholders promotes regulatory transparency as investors know how the utility's returns will be determined and may be able to make forward projections on that basis. Consumer interests can also gauge future rate impacts. A formula that invites regulatory tinkering in its application would not satisfy the objective of regulatory transparency. Any formula that is selected should utilize data that is commercially available. Often, subscription charges apply to the most widely-used data services (e.g., Consensus Forecasts, Bloomberg, Value Line, SNL, I/B/E/S, Thomson, DEX Universe Bond Indices, Moody's), but these costs may be more than offset by the value of the data to the process. Generally, government bond yield data are publicly available, as is dividend data on all publicly traded issues in the U.S. and Canada. Authorized ROE data are publicly available through Board Orders, or subscribing to a research service similar to Regulatory Research Associates (owned by SNL data) that performs this research. Generally, SNL research focuses on U.S. companies and we are not aware of a similar data service for Canadian utilities. Earnings growth rates and betas typically require a subscription to Value Line or Bloomberg, though Bloomberg provides international coverage, while Value Line focuses on companies traded on American stock exchanges. Corporate bond yield indices are often proprietary.

The three primary sources of bond yield data are: Bloomberg, Moody's and DEX by PC Analytics. The following is a brief summary of these data series and sources.

Bloomberg develops a Fair Value Canada 30-Year A-rated Utility curve which is extrapolated from the yields of Canadian A-rated utility bonds at their various maturities. The curve is constructed by applying specific points for various bonds of certain maturities to the curve, adjusting for any mismatch. This curve is updated daily based on the valuations of the securities which comprise the basis for the curve. As each of the bonds rolls down the curve new longer maturities are added. Though these curves are derived, our analyses in Figures 13 and 14 below show that the Bloomberg Fair Value Curve is a reasonable proxy for an actual Canadian bond index, based on A-rated bonds with maturities of 20-30 years.

Moody's provides long term corporate bond yield averages that are derived from pricing data on a regularly replenished population of corporate bonds in the U.S. market, each with current outstanding bond issuances over $100 million. The bonds have maturities as close as possible to 30 years; they are dropped from the list if their remaining life falls below 20 years, or if the bonds are susceptible to redemption, or if their ratings change. All yields reflect yield to maturity calculated on a semi-annual basis. Each observation is an un-weighted average. The average corporate bond yield index represents the average of the corresponding average Industrial and Average Public Utility observations.

DEX – PC Bond Analytics PC-Bond* publishes indices to measure the performance of the Canadian fixed income market. Indices are exclusively Canadian and are widely relied upon for Canadian fixed income performance benchmarks. The Universe Bond Index tracks the broad Canadian bond market for all Canadian corporate bond issuances and is further divided into sub-sectors based on major industry groups: Financial, Communication, Industrial, Energy, Infrastructure, Real Estate, and Securitization. These sectors may also be sub-divided based on credit rating: a combined AAA/AA sector, a single A sector, and a BBB sector; and/or term, which is classified as short (1 – 5 years), mid (5 – 10 years), and long (10 + years). Eligibility requirements include $100 million minimum issues size and investment grade credit rating, among others.

In addition, DEX provides a 20+ Universal Bond Index which includes all corporate bond issuances within a particular credit sector with remaining maturities in excess of 20 years. Eligibility requirements are as stated above. Though this bond index encompasses long term maturities, it is not subdivided by credit rating.

The Universal Bond indices are built with daily history, calculated and available from December 29, 2000 and are published daily. These are also transparent indices, with individual security holdings and prices, disclosed electronically each day. We understand that DEX and PC Bond Analytics tailors its subscription prices to their clients' requirements and price their product accordingly. Concentric's inquiry to pricing indicated a fee of $2,500 for a one-time snap shot of constituents making up the sub-sector "energy" index, and a one-time fee of $1,500 for a complete historical data stream for any one bond index data series requested. We also note that the Company is very restrictive in the use of its data to protect its propriety.

Below we have provided a comparison of the three price series relative to one another for both utility bond indices and corporate bond indices. As the figures below demonstrate, the Bloomberg Fair Value Curve and the DEX PC Bond Analytics Universe curve, both representing Canadian bond yield indices for the utility and energy sectors, respectively, are nearly identical, and accordingly, we conclude that these series are reasonable substitutes for Canadian utility bond yields. The Moody's utility data suggests that the U.S. bond indices and Canadian utility bond indices have diverged in the past, though today all three indices provide similar yields for utility bonds.

Turning to Figure 13, though the corporate bond yield data among the three indices generally move in tandem, we believe the utility bond index (as available in Bloomberg or DEX) is preferable for purposes of adjusting utility equity returns in Canada.

Figure 13: Moody's, Bloomberg, DEX Comparison of Utility Bond Indices

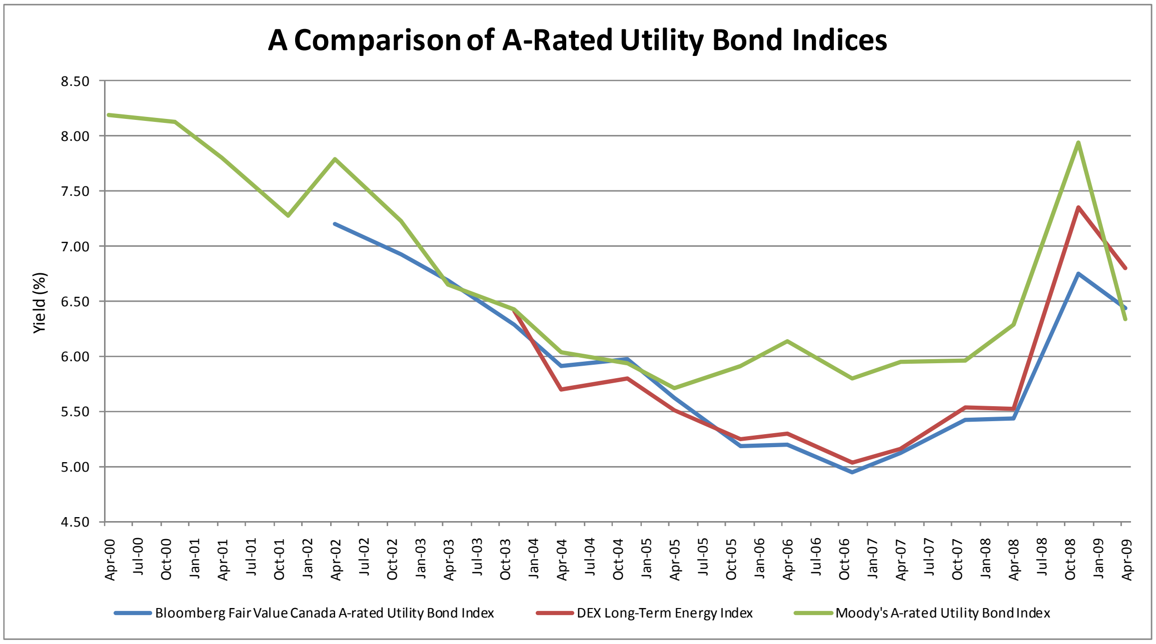
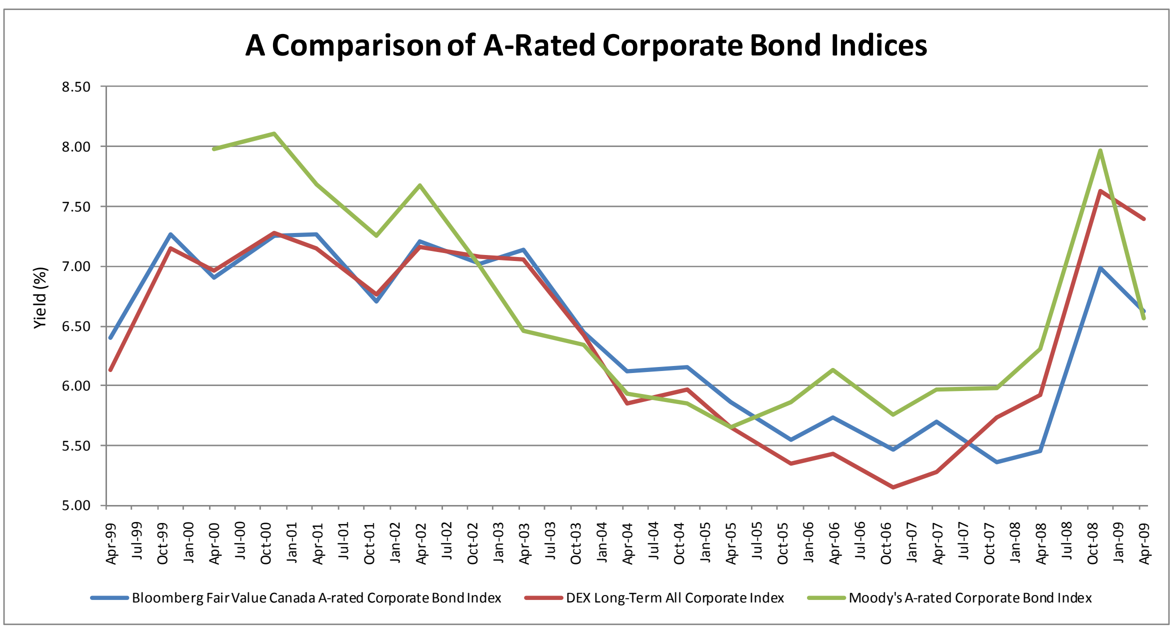


Figure 14: Moody's, Bloomberg, DEX Comparison of Corporate Bond Indices



4. Potential Approaches for British Columbia

In response to the BCUC's December 2009 Order, Concentric has researched and evaluated alternative ROE automatic adjustment mechanisms. In doing so, we have examined formulas used in other North American jurisdictions, selectively researched overseas, and we have also considered other alternatives. Though Concentric is not recommending a formulaic approach, we have identified attributes to be considered should the Commission determine in a future proceeding that a new formula will be adopted in BC. Further, we have examined alternative inputs and parameters used to construct formulas, and compared how these formulas perform over time against non-formulaic results and under varying market conditions. Based on this assessment, we have identified several potential options for a formulaic adjustment mechanism. These approaches vary in terms of their complexity and ease of administration. The first three are indexed based; the last is a more complex multifactor model. Finally, the BCUC may elect to have periodic litigated proceedings (with the potential for settlements) on this matter. Each is described below.

All of the formulaic methodologies provided below could be used to establish a generic benchmark for a low risk, high grade utility, to which adjustments are made to account for risk of a specific utility relative to the benchmark (as is the historic practice in BC); or alternatively could be applied to utility specific ROEs where the base ROE is set specifically for each utility and adjusted in accordance with the AAM (as is the practice in California).

(1) Utility Bond Yield Index

As a general premise, the straight utility bond index is simple to understand and administer and closely resembles the prior BC model, with the substitution of utility bonds for government bonds and a reduced sensitivity to changes in bond yields. Ontario adopted a variation of this approach, which used forecast government bond yields and utility bond spreads (over government bonds) to project utility bond yields.

The general specification for this formula is:

Index: average yields on long term utility bonds of comparable grade to the target utility

- California utilizes the 12 month moving average Moody's Baa or A, depending on the utility rating.
- Ontario utilizes the utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond index yield and the long Canada bond yield, plus the change in the forecast long Canada bond.
- Concentric observes that the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond yield and the DEX alternative move in close proximity, and either should be a reliable indicator of long-term Canadian utility bond yields.

Formula Coefficient Adjustment Factor of 50% - based on the historical relationship between utility bond yields and regulatory authorized returns. For every one percentage point movement in the utility bond yield index, the authorized return will move in the same direction by 50 basis points.

Deadband: none (but could be established)
Trigger Mechanism: none (but could be established)
Term: 3 – 5 years

As a numeric example, the California specification of this model is as follows:

$$ROE_n = ROE_{n-1} + 0.50 \times (Moody's\ Baa_n - Moody's\ Baa\ benchmark)$$

So, if the starting ROE (n-1) is 9.5%, and the utility bond yield increases from 5% to 6%, the new ROE is:

ROE = 9.5 + 0.5*(6.0 – 5.0) = 10.0%

(2) Utility Bond Yield Index with a Deadband and Trigger

A variation of the above simplified bond index approach incorporates a deadband mechanism, as we have seen in California, and potentially a trigger mechanism. The deadband can be used to negate the impacts of smaller changes in the annual bond index, while a trigger can be used to signal a large change from a specified benchmark warranting re-examination of the formula. These features serve as "rails" on the results from the formula.

Index: Similar to the California and Ontario approaches, ROE is indexed to the average yields on long term utility bonds

Formula Coefficient Adjustment Factor of 50%, as above.

Deadband: 50 basis points – To avoid the need to make adjustments to the return portion of the cost of service for small changes in ROE, a deadband may be adopted so that only significant changes from the benchmark lead to a change in authorized return. If the change in the bond yield index is within 50 basis points of the original benchmark, no adjustment to ROE is made. If the bond yield index exceeds the original benchmark by greater than 50%, ROE would be adjusted accordingly and the new bond yield would become the new benchmark. Concentric believes that 50 basis points is a threshold that provides a reasonable balance between regulatory efficiency and providing a return that is reflective of prevailing equity markets.

Trigger Mechanism 100 basis points: A review of the formula is triggered in the event that the formula produces results that are outside plus or minus 100 basis points of a given benchmark. Concentric suggests that the benchmark should be established as the average awarded ROE ("AAROE") for all major Canadian[40] and U.S. gas and electric utilities for the preceding 12 month period. As described earlier, the data for U.S. utilities is readily available through SNL's RRA database. Canadian utility ROEs would be added to this data through an annual review of commission orders for major utilities. To make this trigger non-circular, it would be set only taking into account litigated (non-formulaic) ROE awards. When applying a trigger mechanism, it should be sufficiently wide so as not to trigger a review at the onset of the formula, or alternatively could be calibrated to consider the opening differential between the AAROE benchmark and the utility authorized ROE at the onset.

Term: 3 – 5 years

[40] Except those operating under the prior Canadian formula linked to government bond yields.

As a numeric example, the basic model is:

$$ROE_n = ROE_{n-1} + 0.50 \times (Moody's\ Baa_n - Moody's\ Baa\ benchmark)$$

To account for the deadband:

If $(Moody's\ Baa_n - Moody's\ Baa\ benchmark)$ is less than 0.50, then no change to ROE

If greater than .50, then:

$$ROE_n = ROE_{n-1} + 0.50 \times (Moody's\ Baa_n - Moody's\ Baa\ benchmark)$$

$$Moody's\ Baa_n = New\ Moody's\ Baa\ benchmark$$

And, to account for the trigger:

If *ROEn* is greater or lesser than AAROE +/- 1.0%, then a review of the formula is triggered.

So, if the starting ROE (n-1) is 9.5%, and the utility bond yield increases from 5% to 6%, the new ROE is:

ROE = 9.5 + 0.5*(6.0 – 5.0)= 10.0%

If AAROE is 9.25%, no review of the formula is triggered.

(3) Combined Utility Bond Yield and Average Awarded ROE Index

The intuitive appeal of this approach is equal weighting of the historic Canadian formula (with utility bond yields replacing government bond yields and an updated coefficient of 0.50), and an index of average awarded ROEs in litigated proceedings in Canada and the U.S. It remains relatively straight forward, and captures more information on required investor returns (assuming awarded returns are a reasonable proxy for required returns) than a pure bond related index.

Index: ROE is indexed to the weighted average of average yields on long term utility bonds (as described above) and the AAROE.

Weighting: 50% Bond Yield Index / 50% AAROE Index

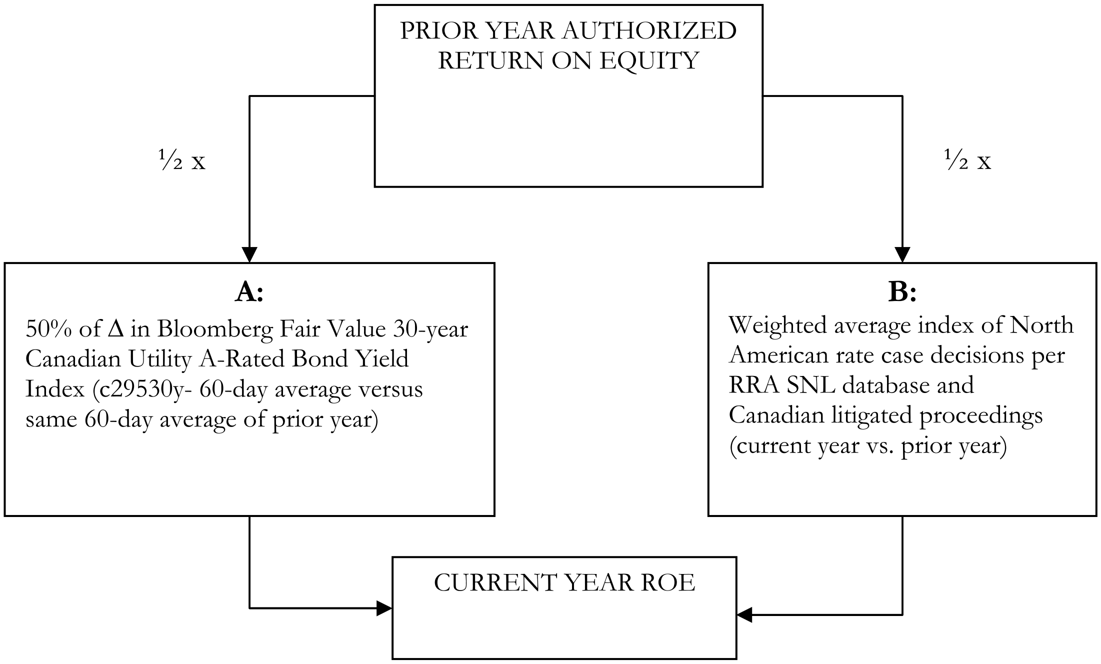
Adjustment Factor: 50% for Bonds, 100% for AAROE

Trigger Mechanism: none

Deadband: none (but could be established)

Term: 3 – 5 years

A diagram of the formula follows:



A numeric example of this formula is:

$$ROE_n = .5\ [ROE_{n-1} + (0.50 \times (Can\ Util\ Bond_n - Can\ Util\ Bond_{n-1})]\ + .5\ [ROE_{n-1} \times (\ AAROE_n / AAROE_{n-1})]$$

So, if the starting ROE (n-1) is 9.5%, and the utility bond yield increases from 5% to 6%, and the index of average awarded ROEs increases from 10.0% to 11.0%, the new ROE is:

ROE = .5 [9.5% + .50(6.0 – 5.0)] + .5 [9.5% (11.0/10.0)] = 10.225%

Intuitively, because of the inclusion of the awarded ROE index which fell further than the bond yield driven formula, and equal weighting of these results, the new ROE falls in between the two results (10.0% vs. 10.45%) at 10.225%. The use of a deadband is a judgment call, but a trigger mechanism in this case is not deemed necessary because of the inclusion of an average awarded ROE term in the formula.

(4) Multiple Method Model

Recognizing that simple models based on one or two inputs may not adequately reflect required returns for utility equity investors, it is possible to create the results from standard estimation techniques employed by cost of capital experts. Rather than scrutinizing the methodologies of competing experts, ROE is estimated based on a predetermined set of methods and inputs. This is analogous to the Mississippi model and proposed NY state framework, and similar to the methodology adopted by FERC. Concentric has adapted a variation of those approaches in this model. The selection of specific inputs and the choice of methods to include in this multi-method model would require further refinement, but the general approach would be as follows.

Determinants:

Proxy Group selection criteria

- North American utilities
- Publicly traded
- Pays dividends
- Primarily regulated utility business (>60% total consolidated revenues)
- Differentiated for gas or electric according to primary business (>60% of regulated utility revenues)
- Comparable credit rating (1 notch above or below is an appropriate guideline)
- No announced significant M&A activity

Discounted Cash Flow Model (DCF)

- The current dividend yield for each company in the proxy group is calculated using the annualized current dividend divided by the average stock price for the most recent 90-trading days. The dividend yield for each proxy group company is increased by one-half of the projected growth rate to reflect the expected growth in dividends over the coming year.
- Earnings growth estimates are averages of the estimates for each of the proxy companies (as available) from Bloomberg, Value Line, Zacks, and Thomson First Call.
- DCF computed as the average for each company in the proxy group.

Equity Risk Premium Model (ERP)

- Risk free rate from the forecasts of U.S. and Canadian 30-year bond yields by taking the average of the 3-month and 12-month forecasts of the respective 10-year government bond yields, as reported in the most recent Consensus Forecast issue. To the forecast of the respective 10-year government bond yield, add the daily average historical spread between 10-year and 30-year bonds for the most recent [30] days. This results in the 30-year bond yield forecasts for the U.S. and Canada in each country's native currency [which are then averaged].
- Market equity risk premium (MERP) from Morningstar Ibbotson, arithmetic mean, average of the long term MERP calculated for the U.S. and Canada
- Utility risk differential calculated based on one of three methods:
    - Historical differential between a broad base of utility stock returns (e.g., Moody's Utility Stock Index) and the broader equity market,
    - Awarded returns in North American litigated proceedings (AAROE) vs. the risk free rate, or
    - The CAPM specification of the ERP, using average adjusted betas for the proxy group from Bloomberg and Value Line, as available.

Weights: 50% DCF / 50% ERP

Trigger Mechanism: none

Deadband: none (but could be established)

Term: 3 – 5 years

A numeric example of this approach is:

$ROE_n = .5 \times DCF + .5 \times ERP$

Thus, if the DCF model produces an average of 11.25% for the proxy group, and the ERP produces 8.75%, the new ROE is set as follows:

ROE = .5 (11.25%) + .5 (8.75%) = 10.50%

There are many variations of this method that could be specified. The DCF could be computed using single-stage, two-stage, or sustainable growth specifications, or taken as an average of these methods. Similarly, the ERP could be computed using all three sources for equity risk premia mentioned above, or extended with the empirical CAPM model (ECAPM). Using multiple methods increases the complexity of the approach, but provides more confidence that the results would emulate those calculated by experts using a variety of methods to bracket the ROE estimate.

(5) Periodic Rate Proceedings

Concentric's research indicates most North American jurisdictions do not rely on a formula for setting the utility cost of capital. Cost of capital is typically set during the course of litigated rate proceedings where company and stakeholder witnesses present independent estimates and the Commission weighs the evidence and determines the fair ROE. Within this approach, several variations are possible:

- Fixed schedule for reset - typically coinciding with a fixed rate application schedule (e.g., annually, bi-annually, etc.)
- Request of the parties - the utility, Commission, or stakeholders may request a rate hearing, including cost of capital, as changed circumstances warrant
- Settlement - the parties may agree to hold rates fixed for a certain period of time, including cost of capital, unless unforeseen market circumstances cause a re-hearing.

The advantage of this approach is its adaptability to changing market conditions, the periodic input from stakeholders, and the ability of the Commission to act on updated capital market information. Generally, ROEs are not volatile over time and in the case of many utilities, periodic rate hearings provide a sufficient response to changing market conditions while retaining stability and predictability in returns. Drawbacks include the additional resources required for litigated cost of capital proceedings, the potential politicization of ROE determinations when other rate pressures emerge, and the potential for companies to remain out of hearings when costs are decreasing.

5. Conclusions

In this report we have examined the utilization of ROE formulas in other jurisdictions and found that a formulaic approach has been selectively adopted by regulatory commissions in Canada and with less frequency in the U.S. In Canada, three provinces remain on a formula (ON, QC and NL). In the U.S., three states have adopted a formula (CA, MS and VT). In addition, Virginia and Florida utilize formulas to establish a range of reasonableness for ROE, as does the FERC with its prescribed ROE methodology. Connecticut is currently investigating the use of a formula.

Formulas adopted in these jurisdictions range from relatively simple models (e.g., the traditional Canadian government bond yield, California's utility bond yield, or Ontario's hybrid of these two), to the more complex multi-method approach adopted in Mississippi. Concentric has evaluated several of these alternatives, a method Concentric has recommended elsewhere, and the prior BC formula. We have compared backcast results with a benchmark of U.S. litigated returns and authorized returns for Terasen, and "stress-tested" the results using the underlying volatility of each model's inputs. Of those we have evaluated using a backcast, the Concentric approach would have come closest to yielding the authorized return by the BCUC in December 2009, assuming this formula was adopted in 1994. The California and Mississippi approaches come closest to the litigated return benchmark over time.

The stress tests suggest that the California and Concentric models are the least volatile, based on the historic standard deviations of the model inputs. Conversely, the Quebec formula (and the prior BC, Ontario and NEB formulas) and the Newfoundland and Labrador formula are the most volatile, due to the greater standard deviations of government bond yields in contrast with other model inputs, and a higher sensitivity to those inputs.

The Commission did not direct Terasen to provide a recommended formula, but rather to "complete a study of alternative formulae and report to the Commission by December 31, 2010." In Concentric's view, this study accomplishes this objective. Each of the four specific formulas described in Section 4 are potential candidates should the Commission elect to adopt a new formulaic approach to ROE. The fifth option, periodic rate hearings, will yield the actual results that a formulaic methodology attempts to emulate and is most likely to meet the Fairness Standard. Based on Concentric's assessment of the ability of each approach to meet the desired attributes discussed earlier, and if the Commission deems it appropriate to reintroduce the formula at a later date, Concentric recommends that the Commission make its determination in consideration of the options presented in Section 4.

INPUTS	ADVANTAGES	DISADVANTAGES
Forecast 10-Year Government Bond Yield	• Widely available • Historical relationship between government bond yields and utility equity returns • Forward looking	• May significantly depart from corporate equity returns - no equity market input • Significantly influenced by national monetary policy and broad macroeconomic trends. • 10-year horizon is not sufficiently long to parallel corporate asset investment horizon (requires a increment to bring the life to 20 to 30 years – could result in mismatching of forecast and historical data) • Not specific to utilities
Historical Avg. 10-Year Government Bond Yield	• Widely available • Historical relationship between government bond yields and utility equity returns	• May significantly depart from corporate equity returns - no equity market input • Significantly influenced by national monetary policy and broad macroeconomic trends. • 10-year horizon is not sufficiently long to parallel corporate asset investment horizon (requires a increment to bring the life to 20 to 30 years – could result in mismatching of forecast and historical data) • Historical performance may not be indicative of future – i.e. not forward looking • Not specific to utilities
Bloomberg historical 30-Year A-rated Utility Bond Yield	• Historical relationship between corporate utility bond yields and utility authorized equity returns. • Less subject to governmental monetary policy and broad macroeconomic trends. • Appropriate investment horizon of 30 years • Data available for both U.S. and Canadian Bond Yields • Derived from frequently updated fair value curve Specific to utilities	• Requires a Bloomberg subscription • Stringent data protection requirements • Not forward looking • Utility bond yields are not always a good predictor of utility equity returns – no equity market input

INPUTS	ADVANTAGES	DISADVANTAGES
Moody's 30-year Baa or A-rated utility bond yield	• Historical relationship between corporate utility bond yields and utility authorized equity returns • Less subject to governmental monetary policy and broad macroeconomic trends. • Appropriate investment horizon of 30 years • Specific to utilities • Widely available for nominal cost – does not require an expensive subscription	• Not forward looking • Utility bond yields are not always a good predictor of utility equity returns – no equity market input • Heavily weighted towards U.S. utilities
Coefficient for Change in Bond Yields of 0.75	• Easily administered • Regulatory transparency	• Overstates impact of historic interest rate fluctuations on utility equity returns, and may change over time • Not supported by regression of utility allowed equity returns and government or corporate bond yields
Coefficient for Change in Bond Yields of 0.50	• Easily administered • Regulatory transparency • Supported by regression of utility allowed equity returns and government or corporate bond yields	• Bond yields, alone, cannot fully explain movements in equity markets
Prescriptive and equal weighting of DCF, CAPM and Risk Premium Approach	• Provides a prescriptive approach to recalculating ROE each year • Specific to utilities and equities • Based on actual equity calculation using commonly applied methods and inputs • Eliminates the controversy around ROE inputs (i.e. risk premium, beta, growth rates)	• More difficult to administer • Inputs can be viewed as subjective and require subscriptions to data services • Data limited to publicly-traded, investor-owned utilities followed by analysts
Weighting of U.S. RRA Index and Canadian Litigated Returns	• Moderately easy to administer • Provides some regulatory transparency • Specific to utilities and incorporates measures of allowed returns on equity (i.e. equity market inputs) • When weighted with Utility bond yields, provides assurance that divergence in equity market from bond market will be at least partially accounted for in the formula result.	• Commissions reluctant to use decisions from other commission in their ROE determinations • Requires reliance on U.S. data • Requires subscription to SNL to develop index, i.e. data is not widely available • Requires Canadian ROE Decision research

INPUTS	ADVANTAGES	DISADVANTAGES
Deadband	• If set properly will avoid frequent and temporary adjustments to ROE - reduces volatility in earnings and rates • Facilitates regulatory expediency by less frequent changes to ROE.	• If not set appropriately may be too sensitive to changes in inputs requiring frequent ROE updates; or conversely be too unresponsive to market inputs
Ceiling and Floors	• Provides certainty that the formula returns will not result in unusually high or low ROE estimates.	• Transfers a portion of market risk from ratepayer to shareholder
Trigger Mechanism	• Provides certainty that significant movements in ROE will be reviewed and the formula's ability to adequately track returns will be reassessed.	• May not adequately address the period for which the formula should be reviewed, i.e. may require review when not needed and not trigger a review when it is needed. • Trigger mechanisms are often set improperly, i.e. changes in ROE do not necessarily translate to ROEs that are inappropriately low or high.
Specified Review Period	• Provides certainty that ROE will be reviewed/ rebased if necessary, and the formula's ability to adequately track returns will be reassessed.	• May not adequately address the period for which the formula should be reviewed, i.e. may require review when not needed and not trigger a review when it is needed.

1. Reference: Cover Letter, June 30, 2011, Page 2, Heading Proposed Regulatory Process

a) As noted, the Negotiated Settlement Agreement concerning the 2007 to 2009 PBR plan extension committed FortisBC to an oral public hearing at their next revenue requirement application. The revenue Requirement Application in this case also has the 2012 Integrated System Plan which sets out a significant long term strategic direction of FortisBC. Please indicate why FortisBC has not requested an oral hearing in light of the NSA settlement and the strategic plan?

Response:

FortisBC recommended a Negotiated Settlement Process (NSP), or alternatively a written public hearing process, for the review of the 2012 – 2013 Revenue Requirements and the 2012 Integrated System Plan because it believes that the Application can be efficiently and cost-effectively reviewed without the need for an oral public hearing. In making this recommendation, the Company considered the workload imposed by an oral public hearing on the Commission and all parties to the process, the respective costs of the potential regulatory processes, and FortisBC's ability to fully address all aspects of its Application through an NSP or written hearing process.

In order to determine whether Registered Interveners agree with FortisBC's recommendation, the Company proposed a Procedural Conference to follow the Information Request phase. The Procedural Conference, as set out in Order G-111-11, will follow two rounds of Information Requests, which the Company believes will provide a comprehensive foundation for either an NSP or the written submissions phase of a written hearing.

FortisBC does have full intention to comply with the NSA regarding an oral public hearing process, if that remains the preference of the Registered Interveners and is ordered by the Commission.

b) Does FortisBC see value in having its witnesses appear before a Commission Panel in regard to policy issues or does it believe NSP processes suffice?

Response:

FortisBC does not believe that there are any material policy issues contained in this Application that could not be addressed through an NSP, but that in any event, an NSP process could be flexible in this regard. FortisBC intended that the Procedural Conference that it proposed to be held following the Information Request phase, would determine, among other things, whether the Application can proceed *in whole or in part* by way of an NSP (2012-13 RRA, Tab 8, page 4).

If the Commission Panel identifies issues that it considers should not be included in the NSP process, those issues could be addressed through written submissions, or if necessary by way of a limited oral hearing. Alternatively, specific issues could be identified at the outset of the NSP as matters of concern to the Panel. These matters could be severed from the rest of the NSP at the discretion of the Panel up front if necessary. A Panel issues list was laid out at the outset of the NSP for FortisBC Energy Inc. (then Terasen Gas Inc.) in its 2010 – 2011 Revenue Requirements Application. The settlement addressed certain of the matters on the issues list and allowed for the Commission to sever them from the settlement if necessary. In that instance the Negotiated Settlement Agreement was approved by the Commission without amendment.

2. Reference: Tab 1, Executive Summary, Page 3, Table 1.2

Please redo the table setting out the forecast and actual for the years 2008, 2009 and 2010.

Response:

Table 1.2 in Tab-1, Page 3 has been updated below setting out the forecast and actual data for the years 2008, 2009 and 2010.

Table BCMEU IR1 2.0

Revenue Requirements Overview

		G-147-07 (*) Approved 2008	Actual 2008	G-193-08 (*) Approved 2009	Actual 2009	G-162-09 (**) Approved 2010	Actual 2010	Forecast 2011	Approved 2011	Increase (Decrease)	Forecast 2012	Increase (Decrease)	Forecast 2013
							($000s)						
1	Sales Volume (GWh)	3,087	3,087	3,107	3,157	3,199	3,046	3,187	3,162	31	3,193	39	3,233
2	Rate Base	822,847	802,566	907,977	867,683	975,113	945,637	1,071,197	1,093,241	52,012	1,145,253	66,928	1,212,181
3	Return on Rate Base	7.47%	7.62%	7.38%	7.83%	7.73%	7.77%	7.96%	7.67%	-0.10%	7.57%	-0.01%	7.55%
4													
5	**REVENUE DEFICIENCY**												
6													
7	**POWER SUPPLY**												
8	Power Purchases	68,538	66,010	70,944	70,776	80,408	71,964	75,956	81,212	9,772	90,984	7,837	98,821
9	Water Fees	7,858	7,878	8,480	8,656	9,068	9,256	8,977	9,381	300	9,681	172	9,853
10		76,396	73,888	79,424	79,432	89,476	81,220	84,933	90,593	10,072	100,665	8,009	108,674
11	**OPERATING**												
12	O&M Expense	45,310	44,725	46,573	46,017	47,645	46,148	53,885	53,885	287	54,172	1,622	55,794
13	Capitalized Overhead	(9,062)	(9,062)	(9,315)	(9,315)	(9,529)	(9,529)	(10,777)	(10,777)	(57)	(10,834)	(324)	(11,159)
14	Wheeling	3,622	3,655	4,010	4,003	4,019	4,050	4,243	3,338	1,387	4,725	508	5,233
15	Other Income	(5,030)	(5,035)	(4,915)	(5,187)	(5,025)	(6,452)	(7,402)	(5,455)	(2,026)	(7,481)	316	(7,165)
16		34,840	34,283	36,353	35,518	37,109	34,217	39,949	40,991	(409)	40,582	2,122	42,704
17	**TAXES**												
18	Property Taxes	11,176	11,036	11,561	11,573	12,548	12,238	13,917	13,940	592	14,532	553	15,085
19	Income Taxes	3,989	5,869	4,354	4,749	5,407	4,544	9,440	6,733	(681)	6,052	1,811	7,862
20		15,165	16,905	15,915	16,322	17,955	16,782	23,357	20,673	(89)	20,584	2,364	22,947
21	**FINANCING**												
22	Cost of Debt	31,762	30,163	34,803	33,411	36,765	35,138	39,364	40,505	814	41,319	2,234	43,553
23	Cost of Equity	29,688	31,001	32,215	34,499	38,614	38,293	45,922	43,292	2,060	45,352	2,650	48,002
24	Depreciation and Amortization	34,356	34,016	37,504	37,376	42,028	41,771	45,350	45,498	5,900	51,399	1,829	53,228
25		95,806	95,180	104,522	105,286	117,407	115,201	130,636	129,296	8,774	138,070	6,714	144,784
26													
27	Prior Year Incentive True Up	22	(1,284)	173	(1,443)	(322)	(2,690)	(2,770)	(1,089)	709	(380)	380	-
28	Flow Through Adjustments	(42)	624	(435)	1,172	(1,068)	2,385	2,406	(2,129)	(276)	(2,406)	2,406	-
	AFUDC / CWIP shortfall	895	-	-	-	-		-	-	-	-	-	-
29	ROE Sharing Incentives	(2,159)	1,314	(1,181)	2,285	(1,300)	(325)	2,630	448	(3,079)	(2,630)	2,630	-
30		(1,284)	654	(1,443)	2,014	(2,690)	(630)	2,266	(2,770)	(2,646)	(5,416)	5,416	-
31													
32	**TOTAL REVENUE REQUIREMENT**	**220,923**	**220,909**	**234,771**	**238,572**	**259,258**	**246,791**	**281,141**	**278,783**	**15,701**	**294,484**	**24,625**	**319,109**
33													
34	Carrying Cost on Rate Base Deferral Account	27		(8)		17			-		-		-
34	ADJUSTED REVENUE REQUIREMENT	**220,950**		**234,763**		**259,274**					**294,484**		**319,109**
35	**LESS: REVENUE AT APPROVED RATES**										283,289		298,618
36	**REVENUE DEFICIENCY for Rate Setting**										**11,195**		**20,490**
37													
38	**RATE INCREASE 2012-13**										**4.00%**		**6.90%**
39	**RATE INCREASE 2014-16 (1)**						**Year 2014:**	**5.8%**					
							Year 2015:	**11.4%**					
							Year 2016:	**5.1%**					

Note (*): BCUC approved annual Revenue Requirement adjusted by BCUC approved BC Hydro rate increase
Note (**): BCUC approved annual Revenue Requirement adjusted by BCUC approved BC Hydro rate increase - Order No.: G-127-10

3. Reference: Tab 1, Page 5, Table 1.3.1

The net load from 2012 to 2013 goes from 34 gigawatt hours to 39 gigawatt hours. Please explain how the increase over the previous year is 1.1 % in 2012 and 1.2% in 2013.

Response:

The 1.1 percent and 1.2 percent are calculated as the increase in net load divided by the total net load forecast in the previous year as shown below. The total net load forecast can be found in Tab 3, Page 2, Table 3.0 of the Application.

2012 Increase over 2011 = 34/3,159 = 1.1%

2013 Increase over 2012 = 39/3,193 = 1.2%

4. Reference: Tab 1, Page 7, Table 1.6, Power Purchase Expense

Please complete the table with forecast to actual for 2008, 2009 and 2010.

Response:

The approved and actual 2008 to 2010 Power Purchase Expenses is found in the table below.

Table BCMEU IR1 4

	Approved 2008	Actual 2008	Approved 2009	Actual 2009	Approved 2010	Actual 2010
			(GWh)			
1 FortisBC	1,572	1,607	1,581	1,585	1,596	1,529
2 DSM	11	0	25	-	30	-
3 Power Purchases (net of surplus sales)	1,824	1,791	1,820	1,893	1,913	1,795
4 Total System Load (before DSM savings)	3,407	3,398	3,426	3,478	3,539	3,324
5 Less DSM	(11)	-	(25)	-	(30)	-
6 Total System Load (including DSM savings)	3,396	3,398	3,401	3,478	3,509	3,324
			($000s)			
7 Expense - Energy	57,312	55,813	59,377	59,921	67,128	61,557
8 Expense - Capacity	12,531	12,624	13,962	11,969	14,876	12,394
9 Capital Projects, Accounting & Other Adjustments	(1,304)	(2,428)	(2,395)	(1,115)	(1,596)	(1,986)
10 Management Expense					0	0
11 Total Power Purchase Expense	68,538	66,010	70,944	70,776	80,408	71,964

5. Reference: Tab 1, Page 8, Table 1.7.1

Please complete Table 1.7.1 for the years 2008, 2009 and 2010.

<u>Response:</u>

Please refer to Tables BCMEU IR1 5a and 5b below.

Table BCMEU IR1 5a (2007-2010)

SL#	DEPARTMENTS	2007 Actual	Labour	Other	2008 Actual	Labour	Other	2009 Actual	Labour	Other	2010 Actual
						($000s)					
1	Power Purchase Management Expense		514	32	546	69	124	739	46	42	827
2	Generation	1,908	189	(203)	1,894	(109)	367	2,152	94	(29)	2,217
3	Utility Operations	12,655	620	(419)	12,856	(256)	500	13,100	486	(431)	13,155
4	Mandatory Reliability Standards	-	-	-		-	-	-	-	-	-
5	Cominco Facility Charge	46	-	-	46	-	-	46	-	-	46
6	Brilliant Terminal Station	3,223	-	(18)	3,205	-	(151)	3,054	-	15	3,069
7	Internal Audit	364	85	(115)	334	20	(6)	348	7	5	360
8	Legal & Regulatory	1,181	247	(135)	1,293	(128)	127	1,292	(84)	243	1,451
9	Customer Service	6,154	(138)	256	6,272	106	(543)	5,835	177	(37)	5,975
10	Aboriginal Affairs	143	22	21	186	3	(36)	153	42	376	571
11	Communications	860	3	30	893	64	40	997	15	55	1,067
12	Human Resources	1,701	169	(331)	1,539	64	(45)	1,558	48	32	1,638
13	Information Technology	2,865	122	(153)	2,834	77	27	2,938	(38)	(76)	2,824
14	Environment, Health & Safety	645	32	(61)	616	22	7	645	106	(24)	727
15	Facilities Management	2,718	84	32	2,834	131	572	3,537	68	95	3,700
16	Finance	2,869	(167)	(220)	2,482	(33)	20	2,469	93	55	2,617
17	Transportation Services	696	49	242	987	4	(347)	644	(41)	(226)	377
18	Supply Chain Management	524	232	(92)	664	(384)	104	384	241	(147)	478
19	Corporate & Executive Management	4,447	(7)	804	5,244	228	654	6,126	(80)	(997)	5,049
20	**TOTAL O&M EXPENDITURE**	**43,001**	**2,056**	**(332)**	**44,725**	**(122)**	**1,414**	**46,017**	**1,180**	**(1,049)**	**46,148**
21	Power Purchase Management Expense	-	-	-	-	-	-	-	-	-	-
22	**Total O & M Expenditures (Prior to reclassification of PPME)**	**43,001**	**2,056**	**(332)**	**44,725**	**(122)**	**1,414**	**46,017**	**1,180**	**(1,049)**	**46,148**

Table BCMEU IR1 5b (2010-2013)

SL#	DEPARTMENTS	2010 Actual	Labour	Other	2011 Forecast	Labour	Other	2012 Forecast	Labour Inflation	Other	2013 Forecast
1	Power Purchase Management Expense	827	110	(9)	927	-	-	-	-	-	-
2	Generation	2,217	304	(334)	2,187	64	36	2,287	176	35	2,497
3	Utility Operations	13,155	410	3,847	17,412	968	123	18,503	387	74	18,964
4	Mandatory Reliability Standards	-	752	203	955	153	71	1,179	8	-	1,187
5	Cominco Facility Charge	46	-	(0)	46	-	(0)	46	-	-	46
6	Brilliant Terminal Station	3,069	-	(82)	2,987	-	173	3,160	-	32	3,192
7	Internal Audit	360	(30)	18	348	72	(24)	396	7	(11)	393
8	Legal & Regulatory	1,451	319	(268)	1,502	8	9	1,520	28	0	1,548
9	Customer Service	5,975	282	155	6,412	172	152	6,737	47	22	6,806
10	Aboriginal Affairs	571	57	(34)	594	21	59	674	(7)	22	689
11	Communications	1,067	120	(284)	903	(183)	203	923	11	18	952
12	Human Resources	1,638	(12)	163	1,789	114	(63)	1,840	(41)	75	1,874
13	Information Technology	2,824	15	(24)	2,815	(48)	74	2,841	(45)	49	2,846
14	Environment, Health & Safety	727	110	70	907	29	(11)	925	35	(7)	953
15	Facilities Management	3,700	(155)	74	3,620	67	(2)	3,685	8	23	3,716
16	Finance	2,617	346	129	3,092	38	145	3,275	55	30	3,360
17	Transportation Services	377	54	335	766	(226)	33	573	20	(0)	593
18	Supply Chain Management	478	183	(111)	550	(25)	(27)	498	(3)	10	505
19	Corporate & Executive Management	5,049	(399)	1,422	6,072	15	(975)	5,112	49	513	5,674
20	**TOTAL O&M EXPENDITURE**	**46,148**	**537**	**7,200**	**53,885**	**1,239**	**(25)**	**54,172**	**736**	**886**	**55,794**
21	Power Purchase Management Exp	-	-	-	-	199	85	1,211	34	21	1,266
22	**Total O & M Expenditures (Prior to reclassification of PPME)**	**46,148**	**537**	**7,200**	**53,885**	**1,438**	**60**	**55,383**	**770**	**907**	**57,060**

6. Reference: Tab 1, Page 13, Table 1.9, Financing Costs 2012 to 2013

Please explain anomalous forecast return on equity of 10.72% in 2011 forecast.

Response:

The 10.72% return on equity is based on forecast earnings for 2011. The Company has forecast 2011 earnings of $45.9 million which includes the ROE Sharing Incentive Mechanism whereby incremental earnings over approved are shared 50% between customers and the Company. The Company's share of the incremental earnings is $2.63 million over approved earnings of $43.3 million. The customers share of the incremental earnings is also $2.63 million and was used to reduce the 2012 revenue requirement.

The calculation of the ROE Sharing Incentive Mechanism is based on a sharing between actual and approved financial performance and this methodology has been in place over the term of the Performance Based Regulation (PBR) agreement pursuant to Commission Order G-58-06. The detailed explanation of the $2.6M variance between forecast and approved 2011 earnings is provided in the response to BCUC IR1 Q94.1.

7. Reference: Tab 3, Load Forecast

a) The BCMEU understands that a technical committee will be struck to review the load forecast. Please provide evidence of the accuracy of FortisBC's load forecast both long term and short term for the past five years.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

b) Would FortisBC agree that as the load forecast plays a key role in the Integrated System Plan filed by FortisBC that it is important that the Commission be comfortable that the load forecast is as accurate as possible?

Response:

Yes. The Commission has indicated by way of the process set out in Order G-111-11 that the review of the Load Forecast by a Technical Committee comprised of the Company, Commission Staff, and Registered Interveners is an appropriate means of addressing the Load Forecast and ensuring it is as accurate as possible.

8. Reference: Tab 3, Load Forecast Technical Committee

Please provide FortisBC's view as to how the Load Forecast Technical Committee's report will impact on the Integrated System Plan.

Response:

The Integrated System Plan includes the 2012 Long Term Capital Plan, the 2012 Long Term Resource Plan, and the 2012 Long Term Demand Side Management (DSM) Plan.

In general terms, the pre-DSM energy and peak demand forecast has the potential to impact the timing of new power system infrastructure and/or upgrades to existing infrastructure (Capital Plan), the volume and timing of power purchases and size and timing of generation resource additions (Resource Plan), and the timing and composition of DSM program expenditures (DSM Plan). The System Planning Forecasts have the potential to impact the location and timing of new power system infrastructure and/or upgrades to existing infrastructure (Capital Plan).

The Integrated System Plan is a strategic and directional framework for meeting customers' needs over the next two to three decades, and was developed with the knowledge that future developments, including the pace and pattern of load growth, are uncertain. Each of the Capital Plan and Resource Plan recognize that the timing and location of resource and infrastructure additions is in part dependent on load growth as opposed to specific timing.

If the committee recommends changes to the load forecast methodology that materially impact the long term forecasts, FortisBC will evaluate the Integrated System Plan in light of those changes. Nevertheless, the Company believes that a Commission finding that the Integrated System Plan is in the public interest does not depend on the exact timing of capital or potential resources acquisition projects, but rather that the proposed solutions/projects are appropriate once those loads are realized.

9. Reference: Tab 4, Page 1, Power Purchase and Wheeling

a) FortisBC seeks the inclusion of management costs associated with Power Purchase costs. Please confirm as indicated in the Workshop that these are not new costs to FortisBC but rather are O&M costs which are being moved to the cost of Power Purchase.

Response:

It is confirmed that these Power Purchase costs are existing costs that are being moved from Operating and Maintenance Expense to Power Purchase Expense.

b) Please identify where the savings arise in the O&M costs as a result of the movement of these management costs to Power Purchase.

Response:

In Table 4.3.1, Tab 4, page 31 of the Application, the 2010 and 2011 Power Purchase Management Expense (Row 1) is shown as part of overall O&M Expenditure (Row 20). For 2012 and 2013, the costs for Power Purchase Management Expense are moved from Row 1 to Row 21, and are no longer included in the Total O&M Expenditure line (Row 20). As a result the O&M costs shown in Row 20 are lower than they would be if this treatment was not approved.

c) Please indicate how the Power Purchase management costs can be monitored to ensure that they are not lumped together with other costs in the Power Purchase costs deferral account.

Response:

The Company does expect that any variance in the Power Purchase Management Expense would flow through the Power Purchase Expense Variance Deferral Account along with other costs. However these costs will be identified as a separate line item, and will be subject to Commission review.

10. Reference: Tab 4, Page 2, Table 4.1-1

BC Hydro power purchase costs go from 29,544,000 in 2010 to 57,965,000 in forecast 2013. Please explain the basis for this significant increase.

Response:

The increase of $28.4 million in BC Hydro purchases between 2010 and 2013 is a result of increased volume of BC Hydro purchases due to increased load, and an estimated increase in BC Hydro rates forecasted at 8 percent per annum. In 2010, the Company purchased 600 GWh of BC Hydro energy at an average cost of $32.36/MWh. The volume was lower than forecast due to reduced load compared to plan, and also due to the Company being able to displace BC Hydro purchases with market purchases at a lower rate. This results in an even larger increase from 2010 to 2013. In 2013, FortisBC is forecasting to purchase 1,020 GWh of BC Hydro energy at an average cost of $41.23 MWh. Of the $28.4 million increase between 2010 and 2013, $16.9 million is due to increased volume and $11.5 million is due to increased 3808 rates.

Given the recent findings from the review of BC Hydro, the BC Hydro rates are forecast to increase by 3.9 percent in 2012 and 2013. This is lower than the 8 percent forecast the

Company used in the 2012 Revenue Requirement Application. This will reduce the forecast BC Hydro purchases by $1.3 million in 2012 and $3.6 million in 2013, and the increase from 2010 to 2013 will be $23.5 million.

FortisBC will revise its 2012-13 RRA prior to setting final rates, to reflect an amended BC Hydro rate application, if filed, or the expected reduction arising from the provincial government review.

11. Reference: Tab 4, Page 12, Line 4, 4.1.2.3, Market Price Forecast Methodology, Line 23

FortisBC states that additionally, these forecasts are converted to Canadian dollars, based on the FortisBC's exchange rates (line 46 of Tables 4.1.4-2 and 4.1.4-3). How does FortisBC adjust for exchange rate variances?

<u>Response:</u>

Actual exchange rates for the month are taken to be the average of the daily exchange rates. This will be different than the exchange rate on the day the US dollar bill is paid. These variances are tracked and periodically the difference will be booked on the Special and Accounting Adjustment line (line 69 of Table 4.1.4-2 and line 70 of Table 4.1.4-3).

For 2012 and 2013, the Company is proposing that 100 percent of exchange rate variances in power purchase expense, as well as all other power purchase expense variances, will flow through to the Power Purchase Expense Variance Deferral Account.

12. Reference: Tab 4, Page 13, Lines 4 and 5

a) FortisBC has indicated that they have included a $0.75 million reduction to power purchase expense in each of 2012 and 2013. How did FortisBC arrive at this level of reduction?

<u>Response:</u>

Please refer to the response to BCMEU IR1 Q12b below.

b) Please provide the analysis which was undertaken?

Response:

The analysis of the estimated $750,000 savings was calculated based on an assumption that the Company will displace 10 GWh of BC Hydro PPA energy in May and 15 GWh of energy in June, in each of 2012 and 2013.

Current market conditions are such that some additional savings may be possible, however. actual savings will depend on the market conditions at the time, which in turn depend on a number of factors such as loads, weather, water levels, gas costs, economic conditions, etc.

The Company therefore believes that an estimate of $750,000 is correct and appropriate at this time taking all these factors into consideration. As detailed in Tab 4, Section 4.1.5 of the Application, 100 percent of the actual variance in power purchases for 2012 and 2013, including variance due to market opportunities, would flow through to the ratepayer through the deferral account. Please see Table BCMEU IR1 12 below.

Table BCMEU IR1 12

2012

		May		**June**
Market Purchases (GWh)		10		15
BCh 3808 Rate ($/MWh)	$	39.11	$	39.11
Market Price Forecast ($/MWh)	$	12.97	$	8.26
Potential Savings	$	261,350	$	462,733
Total 2012 Potential Savings	**$**			**724,083**

2013

		May		**June**
Market Purchases (GWh)		10		15
BCh 3808 Rate ($/MWh)	$	42.24	$	42.24
Market Price Forecast ($/MWh)	$	14.91	$	9.49
Potential Savings	$	273,291	$	491,188
Total 2013 Potential Savings	**$**			**764,479**

13. Reference: Tab 4, Page 34, Table 4.3.2.1, Labour Inflation 2007 to 2013, 2.2, IBEW

When did FortisBC agree to a 5% increase for IBEW in 2012?

Response:

In February 2009, after 12 months of negotiations between the Parties, the Company proposed a four year Collective Agreement providing a 5 percent increase in the fourth and final year of the term. At the time of these discussions the Western Canadian market for linemen was offering 4 - 5.3 percent wage settlements. The Company was aware that its base wage for Power Line Technicians lagged market. To ensure stability and avoid a widening of the wage gap between FortisBC and other Western Canadian utilities, the Company offered a 5 percent increase to secure a longer term agreement. The four year term gave the Parties labour certainty through a period of high capital activity. The Collective Agreement expires January 31, 2013.

14. Reference: Tab 4, Page 98, Lines 7 and 8

FortisBC indicates that there is a "loss of sundry income from the rental poles at FortisBC effective January 1,2011". Please explain why this loss of income occurs.

Response:

Please note that the reference should read "loss of sundry income from the rental poles at **Fortis Inc.** effective January 1,2011" not a loss of income at FortisBC.

Prior to 2011, Fortis Inc. would reduce the amount of Corporate Service Charges allocated to its subsidiaries by the amount of rental income it received under a joint-use pole rental agreement with another party. When Fortis Inc. originally purchased the joint-use poles the seller had an option the buy back the poles under a 10-year agreement. The seller exercised its option to buy back the poles in December 2010.

15. Reference: Tab 5, Page 18

The BCMEU has a concern with respect to expenditures of FortisBC on regulatory and legal matters. Please confirm that $300,000 was spent on the dispute with Shaw, the end result of which is pole contact revenues of $59,000 per year (as identified at Page 8 at Tab 5, Page 18, Lines 13 through 17 and Section 4.81 of the Application).

Response:

FortisBC confirms the $300,000 before tax was spent on the Shaw Application for Transmission Facility Access the eventual result of which was $0.059 million for historic cost recovery of transmission pole rentals as well as ongoing revenues of $0.4 to $0.5 million annually for fibre leasing and transmission pole rentals. Please refer to the response to BCUC IR1 Q68.1.

16. Reference: Tab 5, Page 21, 2012 Integrated System Plan and 2012 to 2013 Revenue Requirements

a) Of the $3.3 million before tax, please identify what amount was incurred to prepare the 2009 Resource Plan which the BCMEU understands is now withdrawn.

Response:

The total cost to prepare the 2009 Resource Plan was $ 0.798 million. It should be noted that the majority of the work used to prepare the 2009 Resource Plan formed the basis for the 2012 Resource Plan and other resource acquisition activity such as the WAX Capacity Purchase agreement.

b) Please elaborate on the reason for withdrawal of the 2009 Resource Plan.

Response:

The review of the 2009 Resource Plan was delayed while FortisBC tried to finalize the 3808 PPA renewal negotiations and obtain clarity on Provincial energy policy. Around the same time, FortisBC negotiated the Waneta Expansion Capacity Purchase Agreement, which was significant enough that that the 2009 Resource Plan would have needed a substantial update in regard to capacity supply and gaps.

Given that the 2012 Revenue Requirements and Long-Term Capital Plan filings were on the planning horizon, FortisBC decided it would be preferable to file the Revenue Requirement, Long-Term Capital Plan, Long-Term Resource Plan and Long-Term DSM Plan together as the FortisBC 2012 Integrated System Plan. The 2009 Resource Plan was withdrawn in conjunction with the current application.

17. Reference: Tab 5, Page 22, Lines 1 and 2

Regarding the $3.3 million before tax, what amount is provided for review of part or all of the application by way of an oral public hearing? What amount will be avoided if the matter does not proceed to an oral public hearing?

Response:

FortisBC expects that approximately $1.0 million in costs would be avoided if the Application does not proceed to an oral public hearing. The reduced costs would be primarily those related to Commission and Intervener funding and to legal fees.

18. Reference: Tab 6, Page 7, Line 23, Information Systems

Please provide expenditures on information systems for the years 2009 through to 2011.

Response:

The expenditures on information systems for the years 2009 through 2011 are provided below:

	2009 Actual	2010 Actual	2011 Forecast
Information Systems	4,768	4,309	4,682

19. Reference: Tab 6, Page 35, Lines 1 through 4

Please provide a copy of the binding agreement with the third party communication provider.

Response:

Please see the attached Appendix BCMEU IR1 Q19 for a copy of the agreement. Note that commercially-sensitive information regarding the detailed financial terms has been redacted on request of the parties to the agreement.

20. Reference: Tab 6, Page 37, Lines 3 and 4

"Additionally, at some point, the necessity for a high capacity communication link between the Okanagan and Kootenay fibre optic systems will become mandatory."

Please describe how this will become mandatory and when this might occur.

Response:

A high-capacity communications link between the Okanagan and Kootenay fibre optic systems is expected to become mandatory in the future for one or more of the following reasons:

- The bandwidth needed for operational data traffic will increase past the limited capacity of the current circuits;
- The current operational data circuits (carried by a third party under an informal agreement with no long-term certainty), are cancelled or become unavailable for other reasons such as technology changes;
- There is a need to exchange critical teleprotection or Remedial Action Scheme (RAS) traffic between the Okanagan and Kootenay areas. Third party leased communications systems are unable to provide the required level of availability for these circuits. According to WECC guidelines, these types of circuits require a minimum end-to-end availability of 99.95%. To meet these requirements, the segment between the Okanagan and the Kootenays would need to have availability greater than the 99.9% typically committed to by third party telecom providers. Furthermore, the same WECC guidelines do not recommend using third party provider leases for critical circuits, except as a secondary path.
- The total operating (lease) costs for growing communications needs (both corporate and operational) between infrastructure in the Okanagan and the Kootenays will become excessive and contribute to increased customer rates; or
- Increasingly stringent Mandatory Reliability Standards requirements will designate existing control and teleprotection facilities as critical and will thus need to be connected to the System Control Centre in Trail over a more secure and reliable link than offered by the current leases.

On this basis, FortisBC anticipates that this infrastructure will be required within the next 4 to 7 years.

21. Reference: Tab 6, Page 85

Please elaborate on the $1 million per year of average cost to customers in Kelowna resulting from outages. What analysis was utilized to arrive at this estimated cost?

Response:

The customer cost of interruption resulting from a one hour outage to all Kelowna load is approximately $5 million (for 250 MW of load in 2007 – Reference: response to BCUC IR1 Q18.4 in the Okanagan Transmission Project evidentiary record). This figure represents the costs borne by customers due to an extended supply outage (such as lost production, business disruption, societal impact, etc.). It is not simply the value of unsupplied electricity service by the utility or incremental utility operating costs related to the outage.

Based on historical performance, failures of the currently installed communications systems will sometimes affect the ability to remotely restore the power system. As a result, what could be a short-duration outage (< 5 minutes) instead results in an extended outage. Also based on this historical performance, FortisBC has estimated that communications failures extend outages times for the substations serving approximately 100 MW of load every two years. A conservative number of 12 minutes per year of outage duration was considered as attributable to these failures; equating to $1 million. Please refer also to the response to BCUC IR1 Q205.1.

22. Reference: Tab 6, Page 89, Lines 12 and 13

Please provide the established practices and guidelines for critical teleprotection applications being referenced here.

Response:

BCMEU IR1 Appendix 22a and Appendix 22b contain the referenced published established practices and guidelines which have been developed by the Western Electricity Coordinating Council (WECC).

23. Reference: FortisBC 2012 Integrated System Plan, Tab 1, Page 2

At lines 3 through 18 FortisBC describes FortisBC and the regulated utilities which are subsidiaries of Fortis Inc. Please provide FortisBC's analysis of the opportunity for synergies with the other Fortis Inc. regulated affiliates which contribute to potential operating efficiencies in the FortisBC 2012 Integrated System Plan, Long Term Resources Plan and Long Term Demand Side Management Plan.

<u>Response:</u>

FortisBC and its regulated affiliates are separate legal entities. The Companies have and continue to operate as separate companies since Fortis Inc. acquired the FortisBC Energy Utilities in 2007. There are only limited opportunities in the areas of materials acquisition through national purchasing agreements, strategic direction and administration with respect to the Company's Integrated System Planning and long term Resource Planning activities. The Companies continue to assess efficiencies around the delivery of energy efficiency (Long Term Demand Side Management), sharing of facilities (Long Term Capital Plan) and sharing of Information Technology (Long Term Capital Plan). The process of identifying and capitalizing on any further potential efficiency is still in its infancy stage. The Company believes that its next submission of its Long Term Plans will demonstrate further efficiencies resulting from collaboration with affiliated Companies. The Company has also included synergies/efficiencies between FortisBC and other affiliates in the Company's Revenue Requirements Application. They include:

National purchasing agreements for certain materials purchases allow FortisBC to access preferential pricing of certain materials. These savings are included in Operating and Maintenance Expense as well as capital budgets.

National coordination of insurance programs allows FortisBC to access insurance coverage that is more cost effective than if the Company were to negotiate insurance coverage on a stand-alone basis. These savings are included within the Operating and Maintenance budgets.

FortisBC and the FortisBC Energy Utilities share a common executive management team. This structure allows for sharing of specialized resources and economies of scale for customers. These savings are included within the Operating and Maintenance budgets.

FortisBC and the FortisBC Energy Utilities share a common Board of Directors, Audit and Risk Committee and Governance Committee. This structure allows for sharing of the costs associated with the Board and its Committees. The costs are shared according to the Massachusetts formula. These savings are included within the Operating and Maintenance budgets.

FortisBC and the FortisBC Energy Utilities share a common internal audit department. This structure allows for sharing of the costs associated with planning and performing internal audits.

The costs are shared based on the relative audit effort expended in each organization. These savings are included within the Operating and Maintenance budgets.

In addition, the Companies will continue to leverage knowledge and experience from each other. These efficiencies are reflected in the operations of the Company.

24. Reference: Tab 2, Page 9, System Development Planning and General Terms

a) Please describe any material changes to the long forecasting approach utilized in developing this long term capital plan versus previous resource plans.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

b) Please provide evidence of the accuracy of historic load forecasting efforts by FortisBC and its predecessor company.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

25. Reference: Tab 2, Page 14, Line 22, Cost of Removal

a) Please provide FortisBC's understanding of the Commission's approach to "cost of removal" in terms of inclusion in revenue requirements.

Response:

The Company is of the understanding that the Commission supports the inclusion of the cost of removal in revenue requirements as per the Commission’s Instructions Section 8, Uniform System of Accounts for Electric Utilities, Plant Retirements:

“Ordinary retirements result from causes reasonably assumed to have been contemplated in prior depreciation provisions, and normally may be expected to occur when plant reaches the end of its expected service life. In the case of such a retirement, accumulated depreciation shall

be charged with the ledger value and the cost of removal and credited with amounts realized for salvage and insurance."

b) Was "cost of removal" included in previous long term capital plans? If not, why not?

Response:

Cost of Removal has not been consistently included across all projects in prior Capital Plans, however Cost of Removal has always been included in the determination of Revenue Requirements.

26. Reference: Tab 7, Page 176, Line 8, SCADA Telecom P&C

FortisBC indicates its "preferred method of communication technology is fibre optic communications". Has FortisBC done any analysis of similar sized utilities serving similar sized communities and markets and policies with respect to installation of utility owned fibre optic infrastructure? Please provide any studies relied on by FortisBC in support of the utilization of utility built fibre optic infrastructure in regions similar to that of the service territory of FortisBC.

Response:

FortisBC has not completed a formal study on the installation of utility owned fibre infrastructure by similar sized utilities, with similar regions and markets and similar service territories.

However, FortisBC has completed analysis on other utilities' practices, through research and informal discussions. The results of this analysis indicate that utilities endeavour to own their own operational communications infrastructure, and it is common practice within the industry to do so. This analysis is confirmed by a key Utilities Telecom Council study examining several utilities in the US. The study concluded that 100% of surveyed utilities owned and operated at least a portion of their wired and wireless network, and 89% owned the network responsible for "network operations and network management communications". The number one reason identified in the study for the utility owning the infrastructure was the low reliability offered by third party providers.

With respect to fibre, FortisBC maintains that the terrain and layout of the service territory is well suited to fibre optic technology, and not to wireless:

- The majority of customers are situated in two long narrow valleys, making it difficult to serve with wireless technology as many mountaintop repeaters would be required in difficult to access terrain.

- Total linear distance is short as the service area and distance between substations is relatively small.

Furthermore, FortisBC also prefers fibre to wireless as it provides long service life, scalable bandwidth and increased reliability (due to no need for supporting equipment such as radios, antennae, towers, power supplies etc).

27. Reference: General

FortisBC is planning to install a second (used) transformer in the Grand Forks substation.

a) What is the valuation of this transformer and the basis for determining this?

Response:

Please refer to the response to BCOAPO IR1 Q24.3.

b) How will installing the second Tx, and removing one old Tx line impact system reliability in GF?

Response:

Installing a second transformer (which would operate in parallel with the existing unit) would provide a fully redundant supply source for the 63 kV network in the Grand Forks area. Compared to the existing system arrangement, it is expected that overall reliability for Grand Forks will increase. This is because currently a failure of the Grand Forks T1 transformer results in an immediate outage to all Grand Forks area load that persists until the supply can be restored using the 63 kV transmission lines from Trail. Following the proposed upgrade, the second parallel transformer would be available to instantly pickup all Grand Forks customer load thus preventing an outage. Since transformer failures occur fairly infrequently but can be of long duration it is difficult to calculate specific deceases in SAIDI or SAIFI reliability statistics.

c) How will this project impact the cost of servicing the GF wholesale customer?

Response:

The project at the Grand Forks Terminal will impact the Grand Forks Municipal customer in a manner consistent with all other customers. In other words, the proximity of the work is of no consequence. All project costs are incorporated into the Company's revenue requirement generally and, if approved, will contribute to the general rate increase and be applied to all customers.

FORTIS BC

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June 30, 2011

Shaw Cablesystems G.P.
Suite 900, 630–3rd Avenue SW
Calgary, Alberta
T2P 4L4

Attention: Dennis Steiger
Group VP, Engineering

Dear Sirs/Mesdames:

Re: FortisBC Inc. Grand Forks to Warfield (Line 11) Extension – Proposed IRU to Shaw Cablesystems Limited

This letter (the "Letter of Intent") is further to the Settlement Agreement (the "Settlement Agreement") made effective as of the 15th day of April, 2011 between FortisBC Inc. ("FortisBC") and Shaw Communications Inc., Shaw Cablesystems Limited ("Shaw Cable"), Shaw Cablesystems G.P. and Shaw Business Inc. (formerly known as Shaw Business Solutions Inc.) (collectively, "Shaw"). Terms used in this Letter of Intent that are defined in the Settlement Agreement, unless otherwise expressly provided herein, have the meanings respectively given to them in the Settlement Agreement.

1. FortisBC hereby confirms that it intends to proceed with the Line 11 Extension.

2. FortisBC hereby confirms, and Shaw acknowledges, that despite Section 5.4 of the Settlement Agreement the Line 11 Extension will run from FortisBC's Grand Forks Terminal Station in Grand Forks, B.C. to FortisBC's A.S. Mawdsley Terminal Station in Warfield, B.C.

3. FortisBC and Shaw Cable will each execute and deliver to one another an IRU Agreement, pursuant to the terms and conditions of which FortisBC will grant to Shaw Cable an IRU over the Additional Fibre (being [redacted] optic strands) substantially in the form of the Penticton - Grand Forks IRU Agreement with such changes as may be applicable, and, in particular, with the "IRU Fee" to be based upon a rate of [redacted]/fibre metre, and with a [redacted] term commencing on a date (the "IRU Commencement Date") that is no later than September 15, 2014 (the "Outside Date").

4. The Parties' obligations described in Section 3 of this Letter of Intent are subject to the satisfaction of the following conditions:

(a) that by no later than December 31, 2012 FortisBC has received the approval of the BCUC for the Line 11 Extension; and

(b) that by no later than the Outside Date the Line 11 Extension has been completed and commissioned and the Additional Fibre meets the Specifications (as that term is defined in the Penticton - Grand Forks IRU Agreement).

5. In the event that the construction and commissioning of the Line 11 Extension is not completed by the Outside Date, the Parties agree to negotiate in good faith with a view to extending the Outside Date. The parties to this Letter of Intent may, by agreement in writing, extend the Outside Date to a date after September 15, 2014.

6. FortisBC and Shaw agree that this Letter of Intent supersedes the provisions of Section 5.4 of the Settlement Agreement, insofar as those provisions establish a procedure for the grant by FortisBC, and the exercise by Shaw Cable, of an option to secure an IRU over the Additional Fibre.

7. The provisions of this Letter of Intent are fully binding upon and enforceable against each of the parties in accordance with their terms.

8. This Letter of Intent shall be governed by and construed in accordance with the laws of the Province of British Columbia.

Please acknowledge and confirm your agreement to all the provisions of this Letter of Intent by endorsing your agreement in the space indicated below and immediately returning one copy to us by e-mail. We would also then appreciate receiving the original signed copy by courier.

Yours truly,

FortisBC Inc.

By: ______________________
R.M. (Bob) Samels
VP Business Planning

Shaw Cablesystems G.P.
hereby acknowledges and agrees to the content of this Letter of Intent dated as of July , 2011

By: ______________________
Dennis Steiger
Group VP, Engineering

By: ______________________
Jay Mehr
Senior VP, Shaw Communications Inc.

SHAW)
07/06/11
Approved
as to form
Legal

Document name	**Guidelines for the Design of Critical Communications Circuits**
Category	( ) Regional Reliability Standard ( ) Regional Criteria ( ) Policy (x) Guideline ( ) Report or other ( ) Charter
Document date	November 18, 2010
Adopted/approved by	WECC Telecommunications Work Group
Date adopted/approved	November 18, 2010
Custodian (entity responsible for maintenance and upkeep)	WECC Telecommunications Work Group
Stored/filed	Physical location: Web URL:
Previous name/number	(if any)
Status	(x) in effect ( ) usable, minor formatting/editing required ( ) modification needed ( ) superseded by ________________________ ( ) other _________________________________ ( ) obsolete/archived)

WECC Guideline:
Guidelines for the Design of Critical Communications Circuits
Date: 11/18/10

Table of Contents

1 Purpose

The purpose of these guidelines is to provide communications system designers with the basic design requirements for communications circuits that carry protective relaying, Remedial Action Scheme (RAS), or other critical communications traffic.
These guidelines also include the design of communication facilities that will ensure the performance of communication circuits. Finally, these guidelines may be used as a resource of collective knowledge and to clarify specific requirements set forth by the *Communications System Performance Guide for Protective Relaying Applications* document.

2 Scope

Communications circuits that are used for critical traffic must perform during all kinds of power system operations and weather conditions. This document addresses the design considerations and requirements for circuits that are used for these or similar purposes, as well as a variety of other types of circuits. Furthermore, this document can be used to interpret what can be done to bring communications circuits into compliance with the policies set forth by the Western Electricity Coordinating Council (WECC).

3 Overview

It is crucial that critical communications circuits perform as required. Since most communications equipment is not hardened, as is other equipment used in the substation, it is more susceptible to noise. Therefore, special precautions must be taken when designing, installing, and operating this equipment.

The *Communications System Performance Guide for Protective Relaying Applications* document sets forth requirements of performance for three classes of communications circuits. For clarification of availability requirements of the three classes of circuits, refer to Table 2 of that document. Please see Section 9 of this document for critical circuit availability calculation methodology.

Recommendations on what to consider when designing circuits used for critical communications follow.

Please note that all standards and recommendations referred to in these guidelines shall be the latest version in effect at time of design. Existing systems designed to previous versions of referenced standards and recommendations shall not be required to conform to the latest version.

4 Abbreviations and Acronyms

A	Availability
AC	Alternating Current
ADM	Add/Drop Multiplex
ADSS	All-Dielectric Self Supporting

ANSI	American National Standards Institute
ATM	Asynchronous Transfer Mode
BER	Bit Error Rate
BICSI	Building Industry Consulting Service International
BIL	Basic Impulse insulation Level
CB	Channel Bank
CSU/DSU	Channel Service Unit / Data Service Unit
DC	Direct Current
DCS	Digital Cross-connect System
DS-0	Digital Signal level 0
DS-1	Digital Signal level 1
EB	Errored Blocks
EDFA	Erbium Doped Fiber Amplifier
EIA/TIA	Electronic Industries Alliance / Telecommunications Industry Association
EM	Errored Minutes
ES	Errored Seconds
ESD	ElectroStatic Discharge
ESR	Errored Seconds Ratio
FIT	Failures In Time
GPR	Ground Potential Rise
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol
ITU	International Telecommunication Union
KBPS	KiloBits Per Second
KV	KiloVolt
LOF	Loss Of Frame
LOS	Loss Of Signal
MOV	Metal Oxide Varistor
MPLS	MultiProtocol Label Switching
MTBF	Mean Time Before Failure, also Mean Time Between Failure
MTR	Mean Time to Restore
MTTR	Mean Time To Repair

MW	MicroWave
NEBS	Network Equipment Building System
NECA	National Electrical Contractors Association
NESC	National Electric Safety Code
NMS	Network Management System
OC-3	Optical Carrier level 3
OOF	Out Of Frame
OPGW	OPtical Ground Wire
PPE	Personal Protective Equipment
QOS	Quality Of Service
RAS	Remedial Action Scheme
RFI	Radio Frequency Interference
RF	Radio Frequency
RMS	Root Mean Square
SD	Space Diversity
SES	Severely Errored Seconds
SESR	Severely Errored Seconds Ratio
SONET	Synchronous Optical NETwork
STP	Shielded Twisted Pair
SWC	Surge Withstand Capability
Telco	Telephone Company
TT	Transfer Trip
U	Unavailability
UTC	Utilities Telecom Council
UTP	Unshielded Twisted Pair
VF	Voice Frequency
VT1.5	Virtual Tributary level 1.5
WECC	Western Electric Coordinating Council
λ	Failure rate per hour
μ	Restore rate per hour

5 Facilities

5.1 General

Due to the vital nature of protection circuits, all telecommunications facilities supporting critical communications circuits shall be designed and maintained to WECC Criterions, NERC Standards, and other industry standards listed in this document. Design elements will consider risks due to severe storms, lightning, fire, flooding, geological disaster, vandalism, electrical disturbances, etc.

5.2 Building Structures

All buildings shall comply with Telcordia Standard GR-43-CORE, Generic Requirements for Telecommunications Huts; specifically, the following sections:

Section 3.18.4	Air-conditioning and Heating Systems
Section 3.22	Structural
Section 3.23	Impact Resistance
Section 3.28	Weather Resistance
Section 3.30	Earthquake Resistance

5.3 Towers

All towers and support structures for microwave transmission antennas shall meet the design criteria of EIA/TIA-222. Any structural modifications or antenna changes will require design review to ensure compliance with EIA/TIA-222 criteria.

5.4 Electrical & Grounding

5.4.1 Ground Potential Rise and Lightning

Lightning/Ground Potential Rise (GPR) surge arresters shall be provided at the AC service entrance or in the charger itself. Arresters that use the avalanche-type device are recommended. These avalanche-type semiconductors respond the fastest and, if not destroyed, will not degrade with each successive lightning strike, as do Metal Oxide Varistor (MOV) devices.

5.4.2 Building Electrical and Power Systems

All building, electrical, and power systems shall comply with the following:

IEEE Std 1100 Recommended Practice for Powering and Grounding Electronic Equipment

Motorola Standard R-56 (Chapters 4 & 5, External and Internal Grounding)

5.5 Power

5.5.1 Equipment Power

All equipment used for critical circuits will be powered from a DC Power Plant with battery backup. Design criteria should include N+1 redundancy for electronic components, such that no single component failure will result in a critical communications circuit outage.

5.5.2 Communications Batteries

Unless the communications equipment is substation-hardened, it is to have its own DC power system, supplied by a separate battery. Large transients can be induced on the substation battery DC bus during a fault resulting from the operation of substation equipment (i.e., opening/closing switches or breakers, etc.). Typically, power line carrier communications equipment is powered by the substation battery because it is hardened. For equipment to be substation-hardened, it must be tolerant to a variety of destructive electrical quantities; specifically, substation-hardened equipment must meet the requirements of:

- ANSI PC37.90.2 (35 Volts/Meter)
- IEC 255-22-3 (RFI Class III)
- ANSI C37.90 (Dielectric)
- ANSI C37.90.1 (SWC and Fast Transient)
- IEC 255-5 (1500 Vrms Breakdown Voltage and Impulse Withstand)
- IEC 255-22-1 (SWC Class III)
- IEC 255-22-2 (ESD Class III)
- IEC 255-22-4 (Fast-Transient Class III)
- IEC 60834-1 (Teleprotection Equipment Performance)
- IEEE Std. 1613 (Standards for Communications Networks in Substations)

To ensure reliable operation, battery plants shall receive regular maintenance and testing. Battery system design should take into account IEEE Std. 1375 “IEEE Guide for the Protection of Stationary Battery Systems.”

5.5.3 Battery Sizing

When sizing the battery, accessibility and travel time to the communications site is to be taken into account. In all cases, the battery shall be sized for a minimum of 8 hours reserve time.

5.5.4 Battery Recharge

The charger is to be sized so that it will be capable of restoring a fully discharged battery to full charge in 24 hours or less while maintaining normal station load.

The quality of DC power supplied to the communications equipment is, to a large extent, determined by the charger. It is important to use a charger-type designed for communications, rather than substations, since it will have a cleaner, filtered output. Steps must be taken to keep transients and destructive surges out of the battery charger, see Section 5.4.1 [**Ground Potential Rise and Lightning]**.

5.5.5 Monitoring

All DC Power Systems will be monitored continuously for “Loss of AC input” and “Rectifier Failure.”

5.5.6 Generators

When required to meet circuit availability requirements and/or for remote sites, stand-by generators will be included in the power system. All generators must be monitored for "generator run" and "generator failure" alarm. To ensure reliable operation, all generators shall receive regular maintenance and testing.

5.6 Security & Monitoring

Buildings shall be monitored continuously for entry, smoke detector alarm, and facility interior high temperature.

Additional security measures shall be considered (fencing, cameras, etc.) on a site-specific basis if warranted by environmental and/or creature activity.

6 Communications Cables

6.1 General

IEEE Std 525 provides descriptions and installation practices for communications cables used in electrical substations. The standard provides guidance to assist the engineer with the proper selection of both metallic and fiber-optic cables. Cables located entirely within the substation ground mat are protected according to each utility's policy, which usually does not include high-voltage isolation. Grounding and protection of these cables does affect circuit availability. Because there is controversy on how to best achieve safety and noise mitigation, each utility has its own methods and standards for dealing with termination of these cables.

6.2 Metallic Cables

6.2.1 Electrical Substations

Metallic communication cables at and around substation and transmission facilities require special protection due to high ground currents that can be present.

When a fault occurs in proximity to a substation or when power lines are operated with unbalanced load currents, there will be a GPR relative to a remote ground. A communications cable that leaves the substation ground mat is subjected to a greater GPR than one which does not. Because of this, protection requirements for copper communications cables are less stringent for cables that are contained within the substation ground mat.

6.2.1.1 Outside Plant

Metallic cables that leave the substation ground mat can carry current surges that result from the potential gradient along the cable during a GPR. These cables, when buried, must be insulated from the ground through nonconductive conduit starting at the control building to at least 2 feet beyond the ground mat. Additionally, these cables must have adequate insulation to keep from shorting through to the elevated ground potential that surrounds the cable at and near the substation ground mat when a fault occurs. The peak GPR determines the dielectric strength of cable insulation required. The estimated peak GPR is calculated from the highest calculated fault current of any feeder coming into the substation.

High-voltage isolation protection must be provided for twisted-pair copper cables, preferably on both ends of the cable. Each pair must be capable of continuous, uninterruptible communications while being subjected to the following high-voltage requirements:

- Failsafe protection limits of 56KV peak (1.2 X 50 microseconds impulse voltage)
- A BIL (Basic Impulse insulation Level) equivalent to the high-dielectric cable specifications in Annex A of IEEE Std 487
- Isolation from 20KV RMS continuous between 5% and 95% humidity

High-voltage protection and isolation is provided with equipment such as that made by Positron, SNC, RLH, and others. This equipment isolates each communications pair with either fiber optics or an isolation transformer. The communications cable shield is left floating at the protection chassis. A high-voltage lightning protector is connected from local ground to the communications cable shield that will activate and short to ground when the potential difference exceeds a high value, typically 5KV peak.

When high-voltage isolation protection is installed at a substation, an investigation must be made to assure that gas tube, solid-state equivalent, or carbon protectors are removed at the substation and within the potential-rise zone near the substation. Should these devices be installed on communications circuits being used for relay protection and activate during a fault, the circuit will be disrupted at the time the protective relaying is needed.

6.2.1.2 Inside Plant

Metallic cables used within the electrical substation ground grid are multiple-pair, insulated cables that can be either Shielded Twisted Pair (STP) or Unshielded Twisted Pair (UTP).

6.2.1.2.1 Grounding Shield

Grounding the shield at both ends of the cable will keep the shield at the local ground potential and minimize hazards to personnel and equipment. However, doing this will also allow low-frequency current (ground loop), which is noise to the communications circuits carried on the cable, to flow in the shield.

Grounding the shield at only one end will provide electric field shielding of RFI and eliminate low-frequency ground loops but may present a hazard to personnel and equipment at the end of the cable that is not grounded. When GPR calculations or measurements indicate hazardous voltage can exist, the ungrounded cable end must be treated as if it were an energized conductor.

6.2.1.2.2 Leased Telco Circuits

When leasing circuits from the local telephone company, GPR calculations made according to IEEE Std 367 must be supplied to the Telco. The Telco will dictate its interface requirements based on its standard procedures.

6.2.2 Communications Facilities
A communications facility is a building or enclosure containing communications equipment that does not have issues with GPR or other surges that are associated with an electrical substation as noted in Section 6.2.1 of this document.

6.2.2.1 Outside Plant
Though a GPR situation does not exist, metallic cables still require protection on every cable pair to protect the end communications equipment from damage due to lightning or voltage surges. In the case of cables owned by the local Telco, protection requirements will be dictated by the Telco.

6.2.2.2 Inside Plant
Inside a communications facility, metallic cables are insulated, multiple-pair cables that can be either STP or UTP. Cables should be installed in accordance with ANSI/NECA/BICSI-568.

6.3 Fiber-Optic Cables
To link substations together, fiber-optic cable may be installed on transmission or distribution lines using OPGW (OPtical Ground Wire), ADSS (All-Dielectric Self-Supporting) cable, or fiber-optic cable supported by a metallic messenger (lashed or figure 8-style cables). The use of a fiber-optical system to serve an electrical supply location should be considered when the bandwidth requirements of wireline facilities are exceeded. In addition, the fault producing the GPR and induction at the electrical supply location may exceed the capability of the metallic wireline facility. In an electrical supply location environment, a fiber-optical system may be viewed as both a communications transport medium and isolation protection, assuming that proper methods for metallic facilities will be deployed.

6.3.1 Outside Plant
IEEE Std 1590 describes the use of fiber-optic cables entering electrical substations. When the all-dielectric, fiber-optic cables are used to serve these electrical supply locations, they will have a nonmetallic strength-support member (i.e., nylon, fiberglass, or equivalent) and shall not contain any metallic pairs that will also be immune to the fault-produced GPR and induction. It is critical that appropriate support hardware be employed to maintain the cables' all-dielectric properties. It is recommended that the last section—from at least 30 m outside the fall line of the phase wires on transmission towers and all parallel runs within the transmission corridor—be underground in non-conducting conduit. If metallic support strands are used or the fiber-optic cable is lashed to existing cables, care must be taken to avoid grounding the strand or anchors within 6 m (see NESC 215C2, 215C3, and 279) of the electrical supply location ground grid.

When OPGW cable or fiber-optic cable with a metallic messenger is used, then there shall be a transition to all-dielectric fiber-optic cable prior to the cable entering any facility or enclosure. Since OPGW or the metallic messenger can conduct fault or induced current, the metallic portions of the cable shall be treated as energized conductors. Personal protective equipment (PPE) and proper grounding techniques are to be used when handling these types of cable.

Fiber-optic cables used for critical circuits within a substation ground grid shall be protected from potential damage. Fiber-optic cables installed in a shared cable trench shall be protected using innerduct or similar product. Fiber-optic cables installed in conduit shall use tracer wire, marking tape, or other electronic device to locate the exact position of the conduit.

6.3.2 Inside Plant

Fiber-optic cables used for critical circuits inside the substation control house shall be protected from potential damage. The use of innerduct or a separate cable-management system is recommended.

6.4 Physical Diversity

In the case of critical circuits for primary and backup relaying or RAS, the circuits shall be routed within the control house, such that there is no credible, single point where both cables can be cut or damaged by the same event. Per IEEE Std 525 Annex I, redundant cable systems shall be physically and electrically separated to ensure that no single event, whether physical or electrical in nature, would prevent a required, specific substation operation. The degree and type of separation required varies with the potential hazards to the cable systems in the particular areas of the substation.

7 Transport Design

7.1 General

7.1.1 Equipment

Equipment used to implement transport systems shall be substation-hardened, NEBS, and/or carrier-grade wherever possible. In cases where these grades are not available, commercial-grade equipment may be used. The equipment shall be redundant wherever possible. If redundant equipment is not available, the equipment's Mean Time Between Failures (MTBF) and Mean Time To Repair (MTTR) shall be accounted for in the calculations of the system availability. The MTTR calculation shall include travel time to the sites involved.

7.2 Multiplex Systems

7.2.1 Frequency Division

Frequency division multiplex systems are suitable for transport of critical communications circuits.

7.2.2 Time Division

Plesiochronous digital hierarchy and Synchronous Optical NETwork (SONET) multiplex systems are suitable for transport of critical communications circuits.

7.2.3 Packet

IP, (G)MPLS, and ATM multiplex systems used for transport of critical communications systems shall be evaluated to ensure delay does not violate the system delay specifications where applicable. Traffic engineering shall be applied to these systems if change in delay due to protection switching cannot be tolerated.

7.3 Microwave Systems

7.3.1 Licensed, Unlicensed, and Registered

Licensed frequency bands are coordinated by regulating bodies to ensure interference free operation.

Unlicensed frequency bands are not coordinated and, correspondingly, are not given any legal recourse by regulating bodies in the event of interference. Therefore, microwave systems using unlicensed bands should not be used to transport critical communications traffic.

Registered frequency bands are similar to unlicensed frequency bands in that there is no recourse in the event of interference. The advantage of the registered band is the registration requirement that allows users to coordinate among themselves and mitigate any interference issues that may arise.

Unlicensed and registered band systems may be used for secondary communications paths to improve transport system availability calculations.

7.3.2 Path Engineering

The goal of path engineering is to meet the desired system availability of the systems being transported on the path. Typically, the systems being transported are traversing multiple microwave paths and, possibly, other types of systems. Therefore, the availability goal of an individual microwave path must be higher than the system availability goal.

Microwave paths are not typically designed to transport a single circuit but, rather, multiple circuits. The microwave path will likely see transported circuits come and go. Thus, future availability requirements may be higher than today.

Microwave path availability shall be calculated using industry standard design models. These availability calculations shall be reduced by appropriate factors when applied to registered and unlicensed bands. These factors should take into account the likelihood of an interfering signal based on location of facilities and congestion of the frequency band used.

7.4 Fiber-Optic Systems

7.4.1 Optical Budget Engineering

Fiber-optic systems shall have enough optical power margin to allow for system degradation without causing a loss of service. The margin shall be at least 3dB for spans up to 16 km and at least 6 dB for longer spans.

7.5 Power-Line Carrier Systems

7.5.1 Coordination

Power-line carrier systems used for transport of critical communications systems shall be coordinated with the Utilities Telecom Council (UTC) to ensure interference-free operation.

7.5.2 System Engineering
Power-line carrier systems shall be designed in accordance with IEEE 643 *Guide for Power-Line Carrier Applications*.

7.6 Telco Leased Lines for Transport

Telco leased lines may be used for secondary paths to improve transport system availability calculations.

7.7 Satellite Systems

Satellite systems are generally not suitable for transport of critical communications circuits due to the inherent delay in satellite uplink and downlink. Any satellite systems used for transport of critical communications systems shall evaluate the system delay to ensure it does not violate the system-delay specifications. Traffic engineering shall be applied to these systems if change in delay due to protection switching cannot be tolerated.

7.8 Monitoring

Transport systems shall be monitored continuously for alarms and failures. Transport systems failures shall be repaired in a timely manner to ensure transport systems availability, or as required by governing standards or recommendations.

8 Circuit Design, Testing, and Monitoring

8.1 General

Availability of an individual circuit is dependent upon the overall system design, including all other sections in this guide, as well as the design of the circuit itself. This section addresses the design considerations and requirements for individual circuits. The requirements for circuit availability of certain classes of protective relaying and RAS circuits have been defined in the *Communications System Performance Guide for Protective Relaying Applications* document.

8.2 Analog Circuits

8.2.1 Balanced Pairs
Twisted pairs in a communication cable are often exposed to common mode noise coming from current that flows in the cable shield. Communications circuits are almost always carried over balanced twisted pairs. This circuit configuration significantly reduces all sources of common mode noise, and the required circuit availability probably could not be met without it.

8.2.2 Analog Signal via Analog Microwave Systems
Analog circuits must be designed for adequate and limited signal-level threshold margin. This will ensure that circuits will operate above the noise incurred during a fault and that a hot signal will not produce the noise associated with amplifiers being driven into clipping.

An adequate receive carrier signal level for analog radio communications will ensure the radio operates in its optimal range for bit error or noise performance. Having adequate fade margin will ensure adequate carrier signal level. A calculated fade margin is to be used that will achieve the required value of availability for the communications path.

Four-wire circuits are limited in level when transmitted over analog microwaves by the constraints imposed by baseband channel-level discipline. This is true for private and carrier microwave equipment. The composite signal level of such circuits must be between –15 and –20 dBm0, while at the same time be a minimum of 6 dB above the manufacturer's guaranteed threshold of operation. This level constraint is necessary to keep from overdriving a fully loaded baseband while, at the same time, ensure adequate signal level for required performance above the noise floor.

For inter-utility circuits, signal interface levels are to be agreed upon by the utilities involved.

8.2.3 Analog Data Circuit Parameters

Analog circuits carrying data shall comply with the applicable circuit type as described in the following standard:

Qwest Technical Publication 77311 (Chapter 4, Voice Grade 36)

Extra care must be given when that analog data circuits are carried over digital channel banks as the channel banks may not be capable of interfacing at the levels specified in the standard and an alternative level discipline have to be developed by the user.

8.2.4 Analog Circuits Over Digital Systems

Analog circuits over digital systems must be designed in such a way as to prevent saturation of the analog end equipment. Special attention needs to be paid to level settings within the digital channel bank. Digital channel bank level settings, which can vary widely based on vintage and specific application, must be determined by the input requirements of the analog end equipment. It should be noted that lower-level circuits (VF) will be dependent on the performance of higher-level circuits (DS-1, OC3, etc.); therefore, care must be taken in provisioning and monitoring higher-level circuits. Additionally, it has been reported that, in certain cases, analog-tone equipment can interpret noise as trip tones on a digital channel (due to loss of frame) if the higher-order digital equipment does not squelch before the relay equipment trips. One advantage of digital systems over analog circuits is that performance monitoring is readily available for the higher-level digital services, whereas it is seldom available for VF services except possibly at the relay equipment.

Circuits should be designed to comply with ANSI T1.512, *Network Performance—Point-to-Point Voice-Grade Special Access Network Voice Band Data Transmission Objectives*.

8.3 Digital Circuits

8.3.1 Compatibility Considerations

Direct digital data rates, protocols, and interfaces are available in a wide and ever-expanding variety. Care must be taken when using different manufacturers or even different lines within a manufacturer's portfolio, or when choosing channel equipment, as there can be compatibility issues between the channel banks. This is especially true with sub-rate channels (channels with rates below 64 kilobits per second [KBPS]).

8.3.2 Testing Standards

ITU-R, ANSI, and Telcordia (formerly Bellcore) have all published recommendations or standards relating to digital communications performance. Recommendations and standards such as ITU-R G.821 and G.826, ANSI T1-503 and T1-231, and Telcordia GR-253 discuss digital communications error performance and performance management.

8.3.3 Error Types and Analysis

Link or circuit unavailability is related to events such as Severely Errored Seconds (SES), Severely Errored Second Ratio (SESR), Errored Seconds (ES), Errored Second Ratio (ESR), Errored Blocks (EB), Loss Of Signal (LOS), Loss of Frame (LOF), or Out-Of-Frame (OOF). Bit Error Rate (BER) is another measurement parameter. BER provides an average measure of circuit performance as long as there is frame synchronization, but it does not capture error events. Error events can be triggered by incidents such as microwave path fading, multiplexer clock or frame slips, hardware or software problems, and maintenance switching. These events all contribute to unavailability or downtime. Other events that can greatly affect downtime are scheduled maintenance, out-of-service testing, and procedural errors. Redundancy and alternate routing can greatly reduce unavailability or downtime.

8.3.4 Monitoring

Many parameters can be used to determine digital circuit Quality of Service (QoS) or performance. Components of a digital communications system—such as SONET and Non-SONET radios, SONET and non-SONET multiplexers, CSU/DSUs, routers, and channel banks—can provide performance-monitoring parameters. Even newer, digital transfer trip and relays can monitor digital communications performance. It is important that digital communications systems have Network Management Systems (NMS) in place to monitor QoS or performance. An NMS system might be as simple as monitoring or logging test-set performance, or could be a more complicated system monitoring or logging inputs from many of the digital system components.

For SONET systems, performance monitoring is embedded in the overhead, but limits performance monitoring down to the VT 1.5 (a SONET encapsulated DS-1) level. CSU/DSU and channel banks may provide performance monitoring down to the DS-0 (64 KBPS) level. Ultimately, end equipment (such as a digital transfer trip) would need to provide performance monitoring to absolutely determine circuit availability or unavailability as related to critical communication circuits. Section 3.2, Table 2, of the *Communications System Performance Guide for Protective Relaying Applications* document shows functional availability for different classes of protective relaying or RAS circuits. Communications system performance objectives must take into account such WECC critical-circuit availability requirements. For example, Class 1 critical protection or RAS circuits must meet a 99.95% availability requirement. Please see Section 9 of this document for circuit availability calculation methodology.

9 Critical Circuit Availability Calculation Methodology

9.1 Introduction

Critical communications circuits that support RAS or bulk transmission-line protection are required by WECC to have a functional availability of 99.95%, or 263 downtime minutes per year, for Class 1 bulk transmission lines [1/]. For Class 1 bulk transmission lines, redundant transfer trip (TT) or protection systems and alternate routed circuits are required to meet "no credible single point of failure" criteria. For Class 2 and lower bulk transmission lines, a single TT or protection system over a single communications circuit may meet the required availability. If the availability is not met, then redundant TT over alternate routed circuits may be required to meet the criteria.

This section describes a simplified methodology that can be used to evaluate telecommunications end-to-end circuit availability for a digital (SONET or non-SONET) fiber, radio, or hybrid system. TT, digital, and/or tone equipment are included in the communications circuit, while protection relays are not. Scheduled restoration activity or maintenance outage time is not used to evaluate availability and is, therefore, excluded from the availability model described in this section.

Although not addressed in this section, individual utilities should evaluate their ability to withstand catastrophic failures that would result in the loss of a communications site or sites, and the associated effects to their power systems (emergency preparedness or disaster recovery programs).

9.2 Reliability Terms and Other Acronyms

A	Availability = (1- U)
λ	Failure rate per hour
FIT	Failures In Time [# of failures over 10^9 hours] = 10^9 / $MTBF_{hrs}$ = $10^9 * \lambda$
$MTBF_{hrs}$	Mean Time Before Failure = 1 / λ [also Mean Time Between Failure]
$MTBF_{yrs}$	$MTBF_{hrs}$ / 8766 hrs/yr [365.25 days/yr*24 hrs/day]
$MTTR_{hrs}$	Mean Time To Repair
MTR_{hrs}	Mean Time to Restore = [MTTR + Travel/Dispatch Time + Spares Avail.] = 1/ μ
Minutes per Year	365.25 * 24 * 60 = 525960
μ	Restore rate per hour
U	Unavailability

Other Acronyms:

ADM	Add/Drop Multiplex
CB	Channel Bank
DCS	Digital Cross-connect System
EDFA	Erbium Doped Fiber Amplifier
MW	Microwave

RF	Radio Frequency (MW or UHF)
SD	Space Diversity
TT	Transfer Trip

9.3 Methodology

Consider a telecommunications circuit as a fiber, radio, or hybrid system with “n” components. The components can be grouped together in a series, or parallel. Examples of components in this context include equipment such as microwave radios (either redundant or non-redundant), SONET Add-Drop Multiplexers (ADMs), and channel banks. Examples of a series system are a collapsed fiber-optic ring or a linear microwave system, as shown in Figure 1 below. Examples of a parallel system are an uncollapsed fiber-optic ring, as shown in Figure 2, or a loop microwave system.

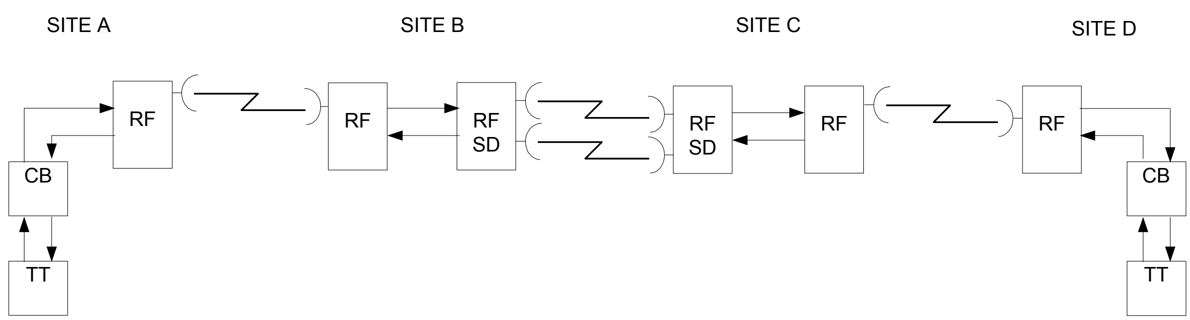


FIGURE 1

LINEAR MICROWAVE SYSTEM

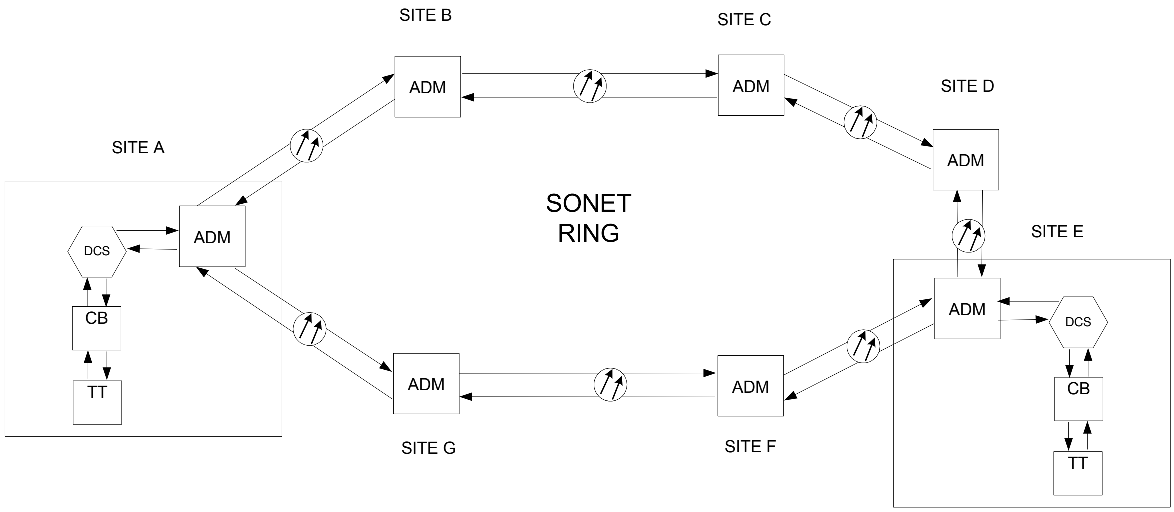


FIGURE 2

SONET FIBER-OPTIC RING SYSTEM

System components can be placed into the following categories:

- Fiber-optic cable
- Fiber-optic equipment, including optical equipment such as Erbium Doped Fiber Amplifiers (EDFAs), optical amplifiers, and optical-to-electrical equipment such as waveshifter regenerators and ADMs
- Radio paths, including Rayleigh and blackout (storm) fading
- Radio equipment, including Radio Frequency (RF), modems, and higher-order, multiplex sub-assemblies
- Other equipment, including digital cross-connect systems, channel banks, site power, and end equipment such as TT (relays are not included)

Modeling end-to-end circuit availability involves drawing components and subsystems that the critical circuit uses. A subsystem can be a SONET ring (which is a group of parallel components) or a linear microwave network (which is a group of series components). A circuit may be routed over multiple subsystems; for example, multiple SONET rings (see Figure 3). Interface equipment used by the circuit to provide entrance or exit from the telecommunications subsystems, or for interconnecting between subsystems (such as DCSs for example), must also be included in the availability calculations.

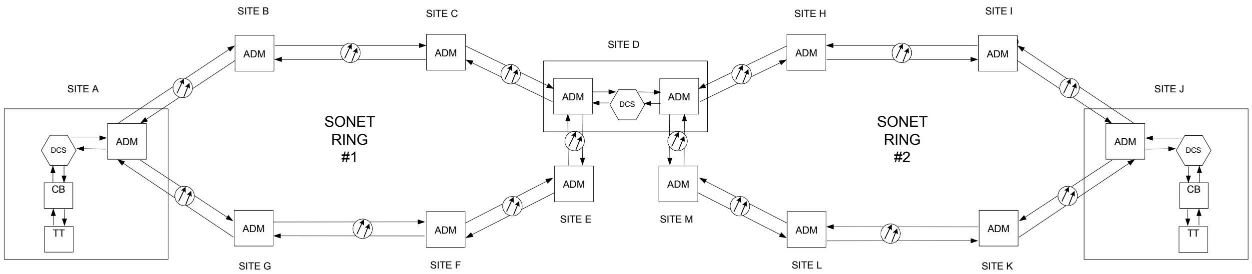


FIGURE 3

MULTI-RING SYSTEM

Annual downtime can be calculated for each ring or subsystem and simply added to the downtime attributed to the end equipment (such as TT) and the communications equipment entering and exiting the rings (ring interface equipment). In the case of non-redundant TT over a single communications circuit and single-homed rings, the availability calculations are straightforward. Availability criteria and "no credible single point of failure" criteria may require redundant end equipment and alternate routed circuits that, in turn, may result in dual-homed rings or other parallel communications routes. In such cases, availability modeling becomes more complex.

9.4 Availability Input Parameters

The model and methodology described herein uses Failures In Time (FIT), from which failure rate (λ) can be calculated, and Mean Time to Restore (MTR), from which restore rate (μ) can be calculated.

A FIT calculation is used to calculate the availability of a circuit. In the case of fiber, the recommended FITs per mile is 342 (212.50 per km), which equates to 3 fiber-optic cable failures per 1,000 route miles per year. A fiber-optic failure rate of 342 fiber-optic FITs per mile (212.50 per km) is based upon telecom industry studies on fiber-optic sheath failure rates [2/]. The recommended fiber-optic failure is again conservative, as not all fiber-optic sheath failures result in service affecting outages (damage to lit fibers). Individual utilities can adjust the fiber-optic failure rate based upon their experience. Within a FIT calculation, the telecom engineer must obtain and input FIT numbers for all of the other system components listed in Section 9.3, except for radio paths.

Microwave point-to-point radio annual outage (downtime) seconds have to be calculated using an RF path engineering software analysis tool. The total RF outage results are directly added into the availability model (in the case of a linear microwave subsystem) or indirectly factored into the model (in the case of a hybrid, fiber-microwave ring). An example of a hybrid, fiber-microwave ring system will be given later.

FIT numbers can be acquired from the various equipment manufacturers. Ideally, the overall FIT number should reflect the exact application for a particular piece of equipment. For example, when calculating the availability of a circuit, the FIT numbers for a pass-through ADM node will be slightly less than the two ADMs that add/drop the circuit. However, for simplicity, if the two FIT numbers are very close, the higher FIT number can be chosen for a particular make and model. Manufacturers may furnish MTBF in lieu of FIT numbers for their equipment. MTBF numbers can then be converted to FIT numbers using the conversion equation given in Section 9.2.

For parallel microwave radio equipment found in hot-standby, frequency, space, and quad (both frequency and space with dual transmit antennas) diversity microwave systems, for example, the manufacturer should be able to provide an equivalent FIT number for the radio. The equivalent FIT number can then be used in linear or hybrid models to calculate system availability (see examples 1 and 4 in Section 9.5 of this document). It should be expected that FIT numbers for quad diversity microwave systems will be lower (due to more parallel components) than hot-standby microwave systems.

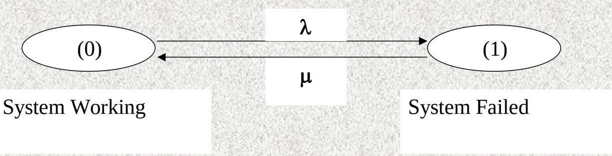
Fiber-optic restoration MTRs are, typically, greater than communications equipment MTRs that are based on the replacement of faulty cards. Therefore, these two different MTR values are used in the model. An MTR of 8 hours is typical for communications equipment inside a control room. Individual utilities should define MTR based on the number of spares and access to the sites in worst conditions. Fiber-optic MTR in the range of 12–24 hours is typical. Circuit availability calculations are particularly sensitive to fiber-optic MTR. Fiber-optic MTR is a very important parameter, and should be based upon the individual utility’s fiber-optic restoration experiences and restoration programs in place. MTR includes incidents where service was restored by rolling service to working, spare dark fiber-optic strands, as well as a complete fiber-optic restoration due to a severed cable. The use of temporary cable and temporary splices can reduce restoration time in the case of complete cable failures.

Software and procedural downtime should be included in the availability calculations. The contribution of software and procedural errors to the system downtime is subjective, but some annual downtime should be allotted.

9.5 Availability Calculations

Figures 4 and 5 show the derived calculations based upon a Markov model to calculate unavailability or downtime for series (linear) or parallel (ring or loop) subsystems, respectively.

Linear System
Markov Model



Linear System Calculations:

$P_0 + P_1 = 1$ $\quad$ $P_1 = P_0 (\lambda / \mu)$

Can derive by substitution:

$P_0 = \mu / (\mu + \lambda)$ [probability of system working or failure free state]

$P_1 = \lambda / (\mu + \lambda)$ [probability of system failed]

Downtime = P_1 * 525960 [minutes / year]

Unavailability (U) = Downtime / 525960 = P_1

Availability (A) = (1 - U) * 100 [%]

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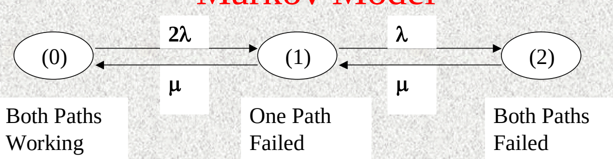
FIGURE 4

SERIES OR LINEAR SYSTEM CALCULATIONS

Ring/Loop System
Markov Model



Ring or Loop System Calculations:

$P_0 + P_1 + P_2 = 1$ $\quad$ $P_1 = P_0 (2 \lambda / \mu)$ $\quad$ $P_2 = P_0 (2\lambda^2 / \mu^2) = P_1 (\lambda / \mu)$

Can derive from substitution:

$P_0 = \mu^2 / ((\mu + \lambda)^2 + \lambda^2)$ [probability of system working or failure free state]

$P_1 = 2\mu\lambda / ((\mu + \lambda)^2 + \lambda^2)$ [probability of 1st component failure]

$P_2 = 2\lambda^2 / ((\mu + \lambda)^2 + \lambda^2)$ [probability of 2nd component failure or system failed]

Downtime = P_2 * 525960 [minutes / year]

Unavailability (U) = Downtime / 525960 = P_2

Availability = (1 - U) * 100 [%]

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FIGURE 5

PARALLEL OR RING/LOOP SYSTEM CALCULATIONS

The linear or series system shown in Figure 4 can be considered an N-1 system. In other words, the first failure will cause a system and circuit outage. The parallel or ring system shown in Figure 5 can be considered an N-2 system. Where there has been an occurrence of a second failure—and before the first failure can be repaired—an N-2 system is considered failed, and a circuit outage occurs. This is a simple, but conservative, methodology. The calculations shown in Figure 5 are conservative in that not all double (N-2) failures on the ring or parallel system would necessarily result in a communications circuit outage.

The formulas shown in Figures 4 and 5 can be incorporated in a spreadsheet to facilitate availability calculations. In this model, critical circuits can be compared and evaluated in a consistent manner. Spreadsheet example calculations, in Microsoft Excel format, are available in *WECC Circuit Availability Calculations.xls* file on the WECC website. These examples include a three-hop, linear microwave system; a two-ring, single-homed fiber-optic system; a two-ring, dual-homed fiber-optic system; and, finally, a two-ring, dual-homed fiber-microwave hybrid system. In the linear microwave and single-homed ring examples, end equipment is non-redundant.

Example 1:

For the linear microwave system in Figure 1, availability calculations can be summarized by the following:

Total system downtime (minutes) = $\text{Equipment}_{series}$ + MW_{fading} + MW_{storm} + Soft.&Proc.

System unavailability (U_{sys}) = (Total downtime) / 525960.
A_{sys} (%) = $(1 – U_{sys})*100$.

"$\text{Equipment}_{series}$" is the total downtime when adding up the individual TT, CB, and RF downtime contributions. "MW_{fading}" is total Rayleigh fading downtime when adding up the individual path contributions. Microwave path profiles and path FIT calculations must be completed for the proposed paths before calculating system availability. An important number for modeling availability is the annual errored seconds (ES) calculated for each microwave path. ESs are typically calculated using a 10^{-6} BER radio threshold. This methodology recommends using conservative, two-way ES path data for evaluating critical communications circuit availability.

"MW_{storm}" is an additional term that represents the amount of annual outage as a result of abnormal storm cells that cause blackout fading that falls outside predicted outages due to Rayleigh fading. "MW_{storm}" is a subjective, optional term that is based upon known, local weather conditions and operating frequency.

Example 2:

For the single-homed fiber-optic ring in Figure 3, availability calculations can be summarized by the following:

Total system downtime (minutes) = $\text{Equipment}_{series}$ + Ring1_{equip} + Ring2_{equip} + Ring1_{fiber} + Ring2_{fiber} + Soft.&Proc.

System unavailability (U_{sys}) = (Total downtime) / 525960.

A_{sys} (%) = $(1 - U_{sys})$*100.

Separate FIT calculations (see Example 2), are needed to calculate the individual ring downtime contributions to the overall circuit availability. ADM, EDFA, and optical equipment FITs must be input for each ring node. Distances between nodes must be input to determine ring fiber-optic FITs. Ring fiber-optic FIT downtime calculations are separated from node equipment FIT calculations due to the different MTRs.

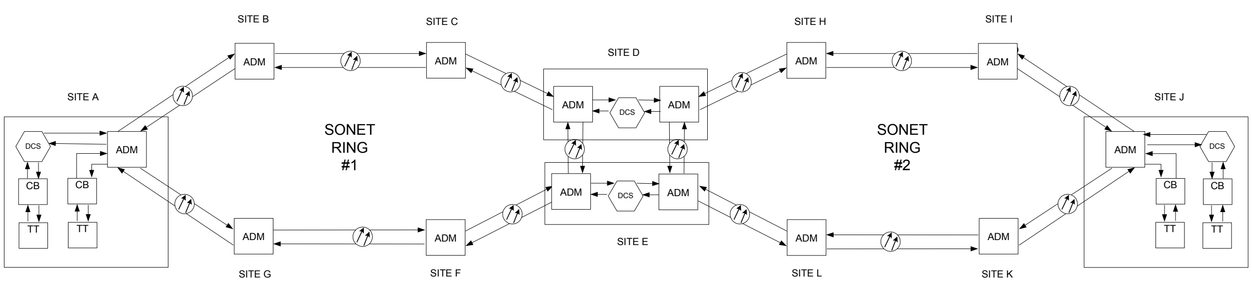


FIGURE 6

DUAL-HOMED MULTI-RING SYSTEM

Example 3:

For the dual-homed fiber-optic ring in Figure 6, availability calculations can be summarized by the following:

Total downtime (minutes) = $\text{Equipment}_{parallel}$ + Ring1_{equip} + Ring2_{equip} + Ring1_{fiber} + Ring2_{fiber} + Soft.&Proc.

System unavailability (U_{sys}) = (Total downtime) / 525960.

A_{sys} (%) = $(1 - U_{sys})$*100.

The same separate FIT calculations, used in Example 2, are needed to calculate the individual ring downtime contributions to the overall circuit availability. Likewise, ADM, EDFA, and optical equipment FITs must be input for each ring node. Distances between nodes must be input to determine ring fiber-optic FITs. Fiber-optic FIT downtime calculations are separated from node equipment FIT calculations due to the different MTRs.

The difference between Examples 2 and 3, however, is the use of redundant, ring-interface communications equipment, and end equipment. The following formulas are used to calculate "Equipment$_{parallel}$" downtime:

$\lambda_{parallelequip}$ = $(FIT_{ckt1equip} * FIT_{ckt2equip} * MTR_{equip}) / 10^{18}$ [Failure rate of parallel equip.]

Downtime (see Figure 4) is finally calculated by:

$Equipment_{parallel} = \lambda_{parallelequip} / (\lambda_{parallelequip} + \mu_{equip})*525960$

where $\mu_{equip} = 1 / MTR_{equip}$

Software and procedural downtime is added to the individual ring and parallel equipment downtime contributions to arrive at a total system downtime.

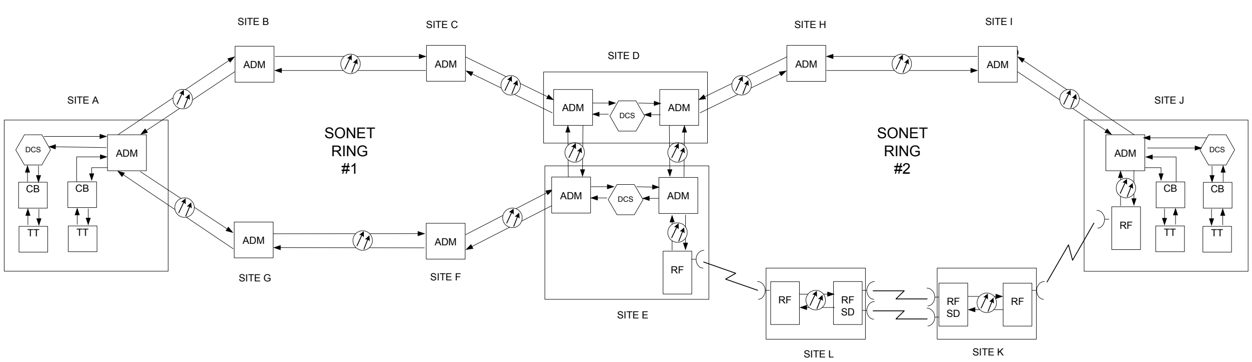


FIGURE 7

FIBER-MICROWAVE HYBRID SYSTEM

<u>Example 4:</u>

For a dual-homed, fiber-microwave ring in Figure 7, the second ring is half MW and half fiber. Availability calculations can be summarized by the following:

Total system downtime (minutes) = $\text{Equipment}_{parallel} + \text{Ring1}_{equip} + \text{Ring2}_{equip} + \text{Ring1}_{fiber} + \text{Ring2}_{fiber} + \text{Ring2}_{mwfade} + \text{Ring2}_{mwstorm}$ + Soft.&Proc.

System unavailability (U_{sys}) = (Total downtime) / 525960.
A_{sys} (%) = (1 – U_{sys})*100.

The same separate FIT calculations, used in Examples 2 and 3, are needed to calculate the individual ring downtime contributions to the overall circuit availability. However, MW radio equipment FITs must be included with ADM, EDFA, and optical equipment FITs for the second ring. Distances between nodes must again be input to determine ring fiber-optic FITs. Fiber-optic FIT downtime calculations are separated from node equipment FIT calculations due to the different MTRs.

Example 3's "$\text{Equipment}_{parallel}$" downtime contribution for the redundant or parallel ring interface communications equipment and end equipment is also used in this example. In this example, however, microwave fading must be factored into the downtime calculations. SONET "matched node" or "drop & continue" added circuit redundancy and complexity are not considered in this example.

As shown in Example 1, microwave path profiles and path FIT calculations must be completed for the proposed paths before calculating system availability. Again, annual <u>two-way</u> errored seconds (ES) are calculated for each microwave path. Unlike Example 1 (a linear MW system), MW fading in this case is considered to only affect the ring 2 downtime if there has been a failure elsewhere in the ring.

For an integrated, fiber-MW ring (a parallel system), MW path fading would only contribute to the system if the fading reached receiver threshold during the restoration period after a fiber-optic cable or other node equipment hardware failure. The probability of system downtime could then be calculated as the product of the probability of a MW fade and the probability of a hardware failure on the system. This is a product term, because the system is parallel—not series or linear. The probability of a hardware failure on the system, $P_{1hardware}$, can be developed from the model given in Figure 5. In this example, $P_{1hardware}$ is the sum of "failure state1 probability," or P_1, for the fiber-optic cable, and "failure state 1 probability," or P_1, for the communications equipment as given by the FIT calculations.

Ring2 $P_{1hardware} = P_{1fiber} + P_{1equip}$.

For Rayleigh fading, the total annual outage (downtime) minutes from the MW ES calculation is used to calculate the total MW fade outage contribution to the ring downtime as follows:

Errored Minutes (EM) = (Total ES) / 60.

$Ring2_{mwfade}$ downtime = (EM/525960) * $P_{1hardware}$ * 525960 = EM * $P_{1hardware}$.

For MW storm blackout fading (optional), a fixed value of X annual outage (downtime) minutes, can also be used as follows:

$Ring2_{mwstorm}$ downtime = (X/525960) * $P_{1hardware}$ * 525960 = X * $P_{1hardware}$.

Software and procedural downtime is added to the ring and parallel equipment downtime contributions to arrive at a total system downtime.

9.6 References

[1]/ WECC *Communications System Performance Guide For Protective Relaying Applications*

[2]/ *The History, Prevention, and Impact of Fiber Optic Cable Failures*, Samuel V. Lisle, Bellcore, June 1993.

[3]/ *Reliability Evaluation of Engineering Systems*, 2nd Edition, Roy Billinton and Ronald N. Allan, Plenum Press, 1992.

Approved By:

Approving Committee, Entity, or Person	Date
WECC Telecommunications Work Group	11/18/2010

COMMUNICATIONS SYSTEMS PERFORMANCE GUIDE FOR PROTECTIVE RELAYING APPLICATIONS

November 21, 2001

This guide was prepared jointly by the WSCC Telecommunications and Relay Work Groups.

1.0 Purpose

The purpose of this guide is to provide communications system designers with basic performance criteria required for communication circuits carrying protective relaying traffic. It is not a detailed design specification. The need for this guide was precipitated by the recognition of potential relay timing problems arising from the application of digital communications and switching technologies. However, since these performance standards are functional they apply to analog, digital or hybrid systems.

2.0 General Comments

2.1 Reliability

The definition of reliability developed by the Relay Work Group reads as follows:

> Reliability of protective relay systems can be divided into two areas: **Dependability and Security**.
>
> **Dependability** The facet of reliability that relates to the assurance that a relay or relay system will respond to faults or conditions within its intended zone of protection or operation.
>
> **Security** The facet of reliability that relates to the assurance that a relay or relay system will restrain from faults or conditions outside of its intended zone of protection or operation.
>
> Two different failure modes are considered: failure to operate and unnecessary operation. All elements in the protective system are considered, including relays, CT's, PT's, communication channels, all supply and control wiring, and station batteries. The only element not considered a part of the protection system is the mechanical malfunction of a power circuit breaker.
>
> **Failure to Operate** is defined as a failure of a terminal, including the relay system and power circuit breaker, to clear a fault when it should.
>
> **Unnecessary Operations** of a relay scheme are classified into two groups:
>
> A. Unnecessary operation in a non-fault condition.
>
> B. Unnecessary operation due to a fault occurring outside of its primary protection zone, (i.e. external fault).

Relay security may also include the ability of a relay or relay system to restrain from operation for an external fault on an adjacent line, transformer, bus, or a component that is several busses removed in some cases. An example of this would be a transmission line pilot communications protection scheme with highly sensitive, overreaching ground overcurrent elements used for start/stop of the pilot communication channel. Some protective relays may misoperate during loss of a relay communication during normal load conditions. All protection schemes should be designed to be tolerant of channel failure conditions.

The definition of protection reliability includes communication channels as part of the protection system. Therefore, communication channels are considered to include all communications equipment required to deliver information from an initiating relay at one location to a receiving relay at another location. For purposes of this guide, reliability of the communications system is therefore a measure of overall reliability. It should be noted that this is not the same measure of reliability or availability as used in path designs.

This definition also highlights the concept that security is an important component of reliability. Security should therefore be an important criterion in the design of communication circuits for relay applications.

2.2 Communications System "End-to-End" Definition

Given that communications channels are defined as in Section 2.1, then the phrase "End-to-End" is taken to mean from the initiating relay to the receiving relay as shown in Figure 1, below. The diagram below is not intended to present the traditional protection systems where all End-to-End communications are external to the protective relay. It includes the newer digital relays that have the ability to initiate and receive the

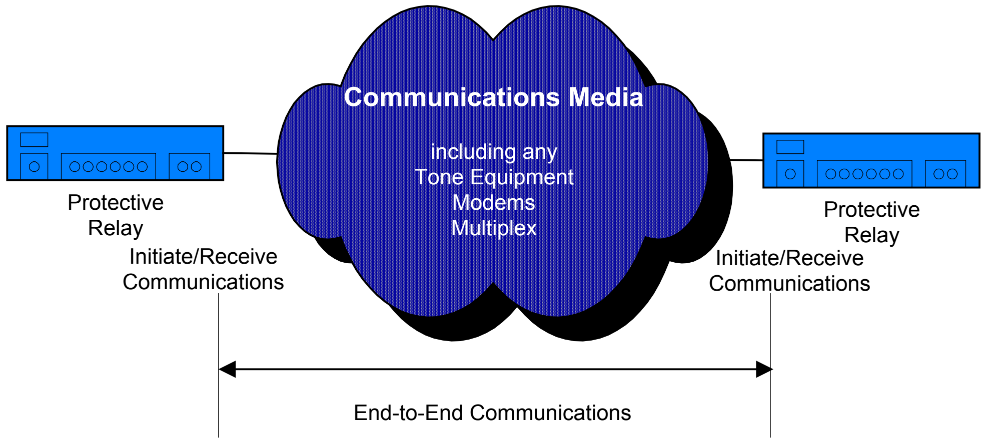


Figure 1. End-to-End Communications Definition

communication signals. Any protective relay delay in processing the communications signal must be accounted for to satisfy the performance specified in Timing Requirements Table, presented later in this document. To make use of this definition; End-to-End delay is the total time delay from the output of the initiating relay to the input of the receiving relay. This delay includes any data buffering associated with digital multiplex. For example, an End-to-End delay of one cycle (16.67 ms) would be the sum of all the equipment and propagation delays existing between the two relays.

2.3 Availability

The communications portion of the protection system must provide a level of availability consistent with the protective relay equipment. Thus availability is total time less unavailability time for all components or support system needed to effect the end-to-end communications linkages divided by the total time in the period measured. Unavailable time will include the communications power systems, hardware outages, radio path fades (if radios are utilized), fiber breaks (which contribute to an outage), software outages and procedural outages (workman error).

Several industry papers have presented discussions on the expected availability of protective relays. The availability is presented as "Protection Unavailability" and "Abnormal Unavailability."

> "Protection Unavailability" is defined as the period of time a protective relay is unavailable due to failure and testing and is dependent on its Mean Time Between Failure, MTBF (or Mean Time To Failure, MTTF) and testing interval.
>
> "Abnormal Unavailability" measures the protection unavailability during a power system element fault.

The Unavailability term can be converted to the communications standard availability term by subtracting unavailability from 1 and converting to percent. The industry papers present Protection Unavailability at $9.4\text{x}10^{-2}$ for standard relays and $1 \text{ x } 10^{-4}$ for relays with self-testing features. These two numbers equate to 90.6 and 99.99 % availability.

It is essential that the communications systems be designed to operate during transmission impairments that are likely to occur coincident with power system faults. Refer to the WSCC Telecommunications Work Group Design Guidelines for Critical Communications Circuits.

2.4 Resynchronization

The two ends of a digital communication system employed to carry protective relay traffic will operate in synchronism. Any communication transmission equipment drop out will result in a need to resynchronize prior to transmission of the communications traffic. The Bellcore standard for SONET requires multiplex equipment resynchronization within 60 ms. Additionally, Bellcore standard TR-TSY-000752 specifies digital microwave to resynchronize in 100 ms on average. Manufacturers typically specify resynchronization times of 100 ms for SONET digital microwave and fiber optic equipment, 50 to 300 ms for asynchronous microwave radios, and less than 50 ms for digital channel banks. Channel drop out should not occur coincidentally with a power system element fault when a communications system is properly designed. A proper design would include particular attention to communications equipment grounding at power stations. Therefore, resynchronization should not be an issue for the use of digital communications systems.

2.5 WSCC/NERC Criteria

In addition to the recommendations in this guide, communication system designs must meet all applicable WSCC Minimum Operating Reliability Criteria (Section 7) and NERC Planning Standards. [2,3,4] This applies to all facilities under WSCC jurisdiction, generally described as bulk transmission facilities.

3.0 Performance Levels

The digital communications performance requirements, which are of concern for protection schemes, are maximum End-to-End delay, variable End-to-End delay, unequal End-to-End delay, availability and redundancy. The three delay concerns are differentiated by the applied protection scheme such as direct transfer trip or phase comparison. Where as, the availability is dependent on whether the scheme is protecting a transmission line or RAS system. Finally, redundancy is required when failure of the protection system will result in violation of the applicable NERC Planning Standards and WSCC Criteria.

3.1 Table Definitions

3.1-1 Protection Scheme

Two State Scheme: Protection schemes whose input to the communication system represents either of two logic conditions (e.g. on/off for DCB, guard/trip for POTT, etc.). There is no analog or encoded data.

Encoded Data: Protection schemes whose input to the communications system represents some type of time sensitive, encoded information (e.g. phase comparison, current differential).

3.1-2 Application

Type of relay protection scheme:

Table Name	Application Name	Description
Direct TT	Direct Transfer Trip	Direct circuit breaker tripping upon receipt of remote trip signal via communications
Permissive	Permissive Overreaching Transfer Trip (POTT), Permissive Underreaching Transfer Trip (PUTT)	Circuit breaker tripping is qualified by both local fault detection and receipt of remote trip signal via communications
Blocking	Directional Comparison Blocking (DCB) Directional Comparison Unblocking (DCU)	Circuit breaker tripping is qualified by both local fault detection and no receipt of remote block signal via communications

Table Name	Application Name	Description
Phase Comparison	Phase Comparison	Circuit breaker tripping is based on coincidence of local and remote waveforms representative of phase current
Current Differential	Current Differential	Circuit breaker tripping is based on coincidence of local and remote phase current waveforms
RAS	Remedial Action Scheme, Special Protection Scheme	Each Remedial Action Scheme is configured to its specific application and cannot be generally described

3.1-3 Maximum End-to-End Delay (Typical)

This is the maximum allowable time delay to meet line-clearing requirements. It is measured from the output of the initiating relay to the input of the receiving relay. This delay includes any data buffering associated with digital multiplex. The maximum End-to-End delay for any protection scheme is dependent on the power system stability requirements. The protection engineer should provide the maximum End-to-End delay allowable for the communications channel. Any actual End-to-End delay that differs from the values presented in Table 1 should be accounted for through adjustment of applicable protection scheme settings.

3.1-4 Variable End-to-End Delay Permitted

A changing End-to-End Delay resulting from communications path switching.

Up to Maximum – the End-to-End delay may vary from zero up to the maximum End-to-End delay.

Relay or Scheme Dependent – End-to-End delay may not vary beyond relay or scheme tolerance.

Solid-state encoded protective relays may be intolerant of variations in End-to-End delay. Such variations in delay result in protective relay misoperation. Some modern microprocessor relays employ a digital messaging system that determines the End-to-End delay while transmitting the data between the relays. These relays block relay operation on channel drop out and do not restore operation until the delay is determined. They are tolerant of variations in delay but not tolerant of unequal End-to-End delays discussed below.

3.1-5 Unequal End-to-End Delay Allowed

A terminal's transmit End-to-End delay differs from its receive End-to-End delay.

Up to Maximum– the End-to-End delay in one direction may differ from the other direction up to the maximum End-to-End delay.

Relay or Scheme Dependent – the relay measures the loop delay, assumes the End-to-End delay in one direction is half of the total and applies this value to align encoded data.

Some modern microprocessor relays employ a digital messaging system that determines the End-to-End delay while transmitting the data between the relays. These relays block relay operation on channel drop out and do not restore operation until the delay is determined. Many of these relays assume the End-to-End delay to be half of the measured loop delay. These relays attempt to align the remote terminal data to the local data with half the measured delay. An unequal End-to-End delay may result in relay misoperation.

3.1-6 Class

The class of transmission line:

Class	Description
1	A bulk power transmission line or RAS requiring totally redundant protection systems to comply with applicable NERC and WSCC Planning Standards.
2	A bulk power transmission line or RAS that does not require totally redundant protection systems to comply with the NERC Planning Standard.
3	A non - bulk power transmission line that may require communications aided protection to satisfy power quality or other requirements of a given utility or customer.

3.1-7 "End-to-end" Functional Availability

The functional availability is related to the overall reliability required for the communication and protection system, reference sections 2.1 and 2.3. This includes all the communication and control systems elements between the end points. The application of redundant equipment or alternate routing of the communication signals will increase the "end-to-end" functional availability. Where a redundant communication system is required by NERC, the required minimum availability value is for the combined, redundant system. Scheduled maintenance is excluded from the availability calculation or measurement. The availability listed in Table 2 is the minimum availability required. Refer to the WSCC Telecommunications Work Group Design Guidelines for Critical Communications Circuits.

3.1-8 Redundancy

The operating criteria for redundancy are given in the applicable NERC and WSCC Planning Standards. Equipment redundancy refers to the active opto-electronic and/or radio shelves, multiplex, Transfer Trip, relay and power supply equipment providing the communication & control functional TT operation. Redundancy may also be used to increase the availability. Refer to the WSCC Telecommunications Work Group Design Guidelines for Critical Communications Circuits.

3.1-9 Alternate Routing to Meet the Specified Availability

Alternate routing of the communication signals may be required to provide the specified availability, the communication system configuration would then be designed so that no creditable single failure will cause loss of the communication, control and protection function(s).

3.1-10 Procedural Outage

These are outages caused by procedural errors. Each outage would typically be of short duration. However, there are many people working which could cause these procedural outages. The procedural outage is the sum of the individual events. Procedural outages are included in the availability requirements of Table 2.

3.1-11 Software Outage

The addition of communication, control and protection equipment that are dependent upon software is the source for these outages. This outage would include software "bug's" which are imbedded in the operational software/firmware that were not found during the pre-qualification or commissioning tests. The software outage total is the sum of individual outages. Software outages are included in the availability requirements of Table 2.

3.2 Performance Tables

Table 1
Timing Requirements

Protection Scheme	Application	Maximum End-to-End Delay (Typical)	Variable End-to-End Delay Permitted	Unequal End-to-End Delay Allowed
Two State	Direct TT	1 cycle @ 60 Hz, 16.67 ms	Up to Maximum	Up to Maximum
	Permissive	1 cycle @ 60 Hz, 16.67 ms	Up to Maximum	Up to Maximum
	Blocking	1/4 cycle @ 60 Hz, 4 ms	Up to Maximum	Up to Maximum
	RAS	1 cycle @ 60 Hz, 16.67 ms	Scheme Dependent	Scheme Dependent
Encoded Data	Phase Comparison	1 cycle @ 60 Hz, 16.67 ms	Relay Dependent	Relay Dependent
	Current Differential	1 cycle @ 60 Hz, 16.67 ms	Relay Dependent	Relay Dependent
	RAS	1 cycle @ 60 Hz, 16.67 ms	Scheme Dependent	Scheme Dependent

Table 2
Functional Availability and Redundancy Requirements

Class	Circuit Application	Minimum End-to-End Functional Availability
1	A bulk power transmission line or RAS requiring totally redundant protection systems	99.95% 265 outage minutes per year One 24-hour outage every 5.4 years
2	A bulk power transmission line or RAS not requiring totally redundant communication and protection systems	99.5% 44.8 outage hours per year Redundancy may be used to achieve this availability
3	A non - bulk power transmission line that may require communications protection to satisfy power quality or other requirements of a given utility or customer	95% 438 outage hours per year Redundancy may be used to achieve this availability

4.0 NERC Planning Standards III.A

The 1997 NERC Planning Standards section III A., System Protection and Control - Transmission Protection Systems, contains two Guides pertaining to communications systems used for protective relaying. The term Guides are defined in the NERC Planning Standards to be "Good planning practices and considerations that may vary for local conditions."[2] These guides address considerations for communications channel testing, monitoring and redundancy.

5.0 References

[1] J.J. Kumm, M.S. Weber, E.O. Schweitzer, D. Hou, "Assessing the Effectiveness of Self-Tests and Other Monitoring Means in Protective Relays", Western Protective Relay Conference, October 1994.

[2] North American Electric Reliability Council Engineering Committee, "NERC Planning Standards", September 1997.

[3] Western Systems Coordinating Council, "Proposed Reliability Management System (RMS)", FERC Declaratory Filing, July 23, 1998.

[4] Western Systems Coordinating Council, "Reliability Criteria for Transmission System Planning", March 1999.

[5] Western Systems Coordinating Council Telecommunications Work Group, "WSCC Telecommunications Work Group Design Guidelines for Critical Communications Circuits", presently under development.

1.0 Reference: Exhibit B-1-2, 2012 Long Term Demand-Side Management Plan

In its 2011 Capital Expenditures Plan application, FortisBC said it plans to complete and file a 20-year Integrated Service Plan in 2011, that this will include planned DSM expenditures, and that it "intends to escalate programs and spending further in subsequent DSM Plan years as internal capacity is developed." 2011 CEP, Exhibit B-1, Appendix 3, p.20, lines 9-10.

1.1 Please confirm the above preamble.

<u>Response:</u>

Confirmed.

1.2 Please discuss whether and how the 2012 DSM Plan implements an intention to escalate programs and spending further in subsequent DSM Plan years as internal capacity is developed.

<u>Response:</u>

As stated in Exhibit B-1-2, page 14, "In this plan, FortisBC has included all programs identified in the Conservation Potential Review reports in which the program TRC ratio is above unity, which supports the objective of pursuing all cost-effective DSM." The avoided long-term supply cost has been reduced since the 2011 CEP, which has reduced the TRC value of the individual DSM measures, and therefore limited the need to escalate programs and spending.

The DSM Plan continues to meet the FortisBC commitment to offset 50 percent of incremental growth through cost-effective DSM.

In addition to the energy savings expected through the DSM Plan, FortisBC expects to increase conservation through the implementation of conservation rates and a customer information portal implemented as part of the proposed AMI project.

2.0 Reference: Exhibit B-1-2, 2012 DSM Plan, 3.5 Collaborative Programs

2.1 To what extent will the acquisition of the Terasen Gas Utilities by the FortisBC Energy Utilities allow increased collaboration between the DSM activities of FBC (electricity) and FEU (natural gas)?

Response:

FortisBC has always collaborated closely with other BC utilities. It is uncertain at this time how extensive the integration of the utility DSM programs will be, keeping in mind the utilities remain distinct corporate entities operating in only a partially overlapping service territory. Opportunities are sought on an ongoing basis to bring collaborative integrated offers to customers.

Examples of collaborative program delivery efforts for residential programs:

- Energy Star clothes washer rebate program;
- Scratch ‘n Win promotion (rebate program for energy assessments);
- City of Rossland on an Energy Diet campaign;
- Community Outreach activities; and
- On-Bill Financing Pilot Project.

Examples of collaborative education programs:

- Shared sponsorships of trade show booths and/or sponsorships;
- Home for Learning (Okanagan College) sponsorship;
- Destination Conservation for Schools;
- Program sponsorships;
    - o Environmental Mind Grind (grades 4-12);
    - o Climate Change Showdown;
    - o Wildsite; and
- Curriculum-based elementary school education program (in development).

Examples of collaborative commercial and industrial programs:

- Building Optimization Program (in development)

2.2 Does FBC have any plans to share DSM staff with FEU?

Response:

Not at this time, although the staff in both utilities communicate regularly.

3.0 Reference: Exhibit B-1-2, 2012 DSM Plan, 1.2 The Act and DSM Regulation

FBC refers to section 4 of the DSM Regulation.

3.1 To clarify, does FBC assert that all the subsections of s.4 of the DSM Regulation apply to the Commission's consideration of FBC's 2012 DSM Plan and that the Plan meets those requirements?

Response:

Yes, FBC believes that all the subsections of section 4 of the DSM Regulation apply to the Commission's consideration of FBC's 2012 DSM Plan. FortisBC believes that its DSM Plan meets those requirements, but notes that in regard to subsection 4(7), the Company has not explicitly included in its DSM benefits calculations any effects of increased market share of regulated items.

3.2 Specifically, subsection 4(3) provides that the Commission must consider the benefit of the avoided supply cost to be BC Hydro's long-term marginal cost of acquiring new electricity. Does this apply to FBC's 2012 DSM Plan? Does FBC use BC Hydro's long-term marginal cost of acquiring new electricity in the benefit cost tests it applies to DSM programs in the Plan?

Response:

The 2012 long-term DSM Plan, and the 2012-13 Capital Plan filing use a blended avoided cost, which incorporates the BC Hydro long-term marginal cost of acquiring new electricity for the portion of electricity FortisBC acquires from BC Hydro, in order to determine DSM benefits.

Please also refer to the response to BCUC IR1 Q296.1.

4.0 Reference: Exhibit B-1-2, 2012 DSM Plan, 2.1 Planning Principles

"2. The DSM Plan will be cost effective by including only those measures, with the exception of prescribed measures, which have a TRC Benefit Cost ratio greater than unity on a portfolio basis";

4.1 Please confirm that the FortisBC Energy Utilities in their 2012-2013 Revenue Requirements Application are proposing to use a Societal Test rather than the Total Resource Cost (TRC) test as the primary benefit- cost test for demand-side management programs. Please elaborate if necessary.

Response:

Confirmed. The FortisBC (electric) DSM program portfolio is sufficiently robust without the use of the Societal Cost Test due to the use of the long-term marginal supply cost in the TRC calculation as mandated in the DSM Regulation. The long-term marginal supply cost, which incorporates the cost of the BC Hydro call for clean power, is currently about twice the current FortisBC marginal supply cost. This creates a larger avoided power purchase benefit and therefore increases the TRC.

4.2 Why is FortisBC Inc. in the 2012 DSM Plan not proposing to use a Societal Test for DSM programs?

Response:

Please see the response to BCUC IR1 Q4.1.

4.3 Does FBC intend to explore using a Societal Test for DSM programs in the future?

Response:

FortisBC is not considering a change to its cost effectiveness test at this time, but FortisBC is aware that the provincial government is considering changes to the DSM Regulation and will comply with any changes to the Regulation.

5.0 Reference: Exhibit B-1, 2012 DSM Plan, 2.4 Conservation and Demand Potential Review (CDPR)

5.1 Does FBC use an 85% achievability factor for all customer classes?

Response:

Yes, the 85% achievability factor was used for all customer classes.

6.0 Reference: Exhibit B-1, 2012 DSM Plan, 2.5 Selection of Plan Option; Table 2.5 Program Options Overview

"The Medium option was selected as appropriate as a baseline for the 2011 DSM Plan." (p.12)

"The High option also received support, but escalating the 2012 DSM Plan to the High option, is not considered prudent because it contains more uneconomic measures (B/C ratio < 1.0), increases spending by paying a larger portion of the TRC cost, and hence increases the magnitude of rate increases due to the decreased load." (p.12)

6.1 In Figure 2.5, does the TRC B/C ratio >0.9 for the High Option mean that the whole portfolio had a TRC >0.9 or that each program within the portfolio had a TRC >0.9?

Response:

Each program within the High option portfolio had a TRC ratio > 0.9.

6.2 Would it be feasible to development a 'Medium-High' option in which the portfolio TRC is greater than one?

Response:

Yes, although it should be noted that any new option developed at the current long-term marginal cost will have a lower TRC ratio than would have been calculated when developing the three options outlined in the 2011 DSM Plan. The DSM Plan proposed for 2012-2013 includes all program measures with a TRC ratio greater than one and a small number of measures below that threshold.

6.3 Please confirm what long-term marginal cost of avoided supply was used to calculate the TRC B/C ratios in Table 2.5.

Response:

Table 3.2.1 as corrected in Errata 2 provides the blended long-term avoided power purchase cost of $101.34/MWh, which was used to calculate all of the benefits in the 2012 long-term DSM Plan and the 2012-13 Capital Plan filing.

7.0 Reference: Exhibit B-1, 2012 DSM Plan, 1.2 The Act and DSM Regulation; 3.2.1 Updated Avoided Power Purchase Costs

7.1 Please reconcile FBC's use of a blended avoided power purchase cost, combining BC Hydro's long-term avoided cost with FBC's market purchase estimated avoided cost, and DSM Regulation s.4(3) which provides that the Commission must consider the benefit of the avoided supply cost to be BC Hydro's long-term marginal cost of acquiring new electricity.

Response:

Please refer to the response provide to BCUC IR1 Q296.1

8.0 Reference: Exhibit B-1-2, 2012 DSM Plan, Table 3.2.2 Benefit Cost Ratios by Sector; Table 2.5 Program Options Overview

8.1 Please reconcile the portfolio and sector TRC B/C ratios shown in Table 3.2.2 with the program options TRC B/C ratios shown in Table 2.5.

Response:

Table 2.5 shows the individual program measure TRC B/C screening thresholds that were used to develop the three program options presented. They do not represent the portfolio-level TRC B/C of each option.

The TRC B/C ratios shown in Table 3.2.2 are the portfolio-level TRC B/C ratios for the 2012-2013 plan proposed as part of the Capital Expenditure Plan.

9.0 Topic: 2012 Long Term DSM Plan

Reference: Exhibit B-1-2, p.1; Figure 3.2.4 Acquired DSM vs. Load Growth Forecast

"The first five years of the 2012 DSM Plan (2012-2016) are an extension of the approved 2011 DSM Plan, thereafter a constant savings target is used as a placeholder for future DSM activities." (p.1, lines 17-18)

"Use of this proxy figure reflects the lesser certainty of DSM Plan figures going farther into the future, while fulfilling the *BC Energy Plan* target of a 50 percent load growth offset." (p.15)

9.1 Is the "lesser certainty of DSM Plan figures going farther into the future" the only reason for the placeholder DSM savings value for 2017 to 2030 being less than forecasted DSM savings in 2011-2016?

Response:

The fact that the levels of DSM are lower than 2011-2016 levels is a result of applying the 50% target to the forecast levels of incremental growth.

9.2 Please confirm that there is lesser certainty of incremental load growth figures farther into the future. Are estimated incremental load growth figures reduced due to this lesser certainty?

Response:

Load growth figures from further into the future are less certain than load growth figures closer to the present. Incremental load growth figures are not, however, reduced due to lesser certainty.

9.3 Please provide whatever evidence supports the assumption that DSM savings estimates beyond 2016 are expected to be lower than the 2011-2016 levels.

Response:

The Company believes the DSM savings proxy, which is used beyond 2016, is a prudent approach that achieves the Company and BC Energy Plan goal of offsetting 50 percent of incremental load growth through DSM. The fact that the levels of DSM are lower than 2011-

2016 levels is simply a result of applying the 50 percent target to the forecast levels of incremental growth.

9.4 Please comment on the suggestion that it appears that FBC is limiting its DSM savings forecast past 2016 to 50% of forecasted load growth.

Response:

FortisBC can confirm that it has set it DSM savings forecast past 2016 at 50 percent of forecast load growth. The forecast of DSM savings for those years will be updated prior to 2016.

9.5 With reference to Figure 3.2.4, if DSM Savings were to stay at the 2016 level (approx. 32 GWh) through to 2030, rather than declining to approximately 28 GWh, would Net Load Growth decline from 2016 onward?

Response:

Yes, net load growth would decline relative to the current forecast but it would still be positive.

10.0 Topic: 2012 Long Term DSM Plan

Reference: Exhibit B-2, DSM Trends, p.28

The $/customer trend line rises from 2002 to 2010, then rises steeply to 2011 and then declines slightly in 2012 and 2013.

10.1 Is the 2011 $/customer value based on the estimated actual spending or approved spending? How big is the difference?

Response:

The 2011 figure of $48/customer shown in the referenced exhibit is based on the approved budget. The current year-end forecast anticipates a positive variance (under budget), which will reduce the nominal DSM expenditure by about $10 per customer.

10.2 Please confirm that the 2012 and 2013 $/customer line is based on projected figures.

Response:

Confirmed, the expenditures are based on the 2012-13 CEP filing, and the customer count is projected.

10.3 Please extend the graph on p.28 to 2030.

Response:

The Company is unable to extend the graph beyond 2013 as the necessary figures, particularly DSM budgets, are not yet complete. However, based on the fact that the forecast energy savings are relatively flat as compared to 2011-2013, the graph is expected to be as well.

11.0 Reference: Exhibit B-1-2, 2012 DSM Plan, 3.8 Education Programs; Exhibit B-1, 7. DSM, 7.3.3.4 Education Programs

11.1 Does FBC consider its public schools DSM education programs sufficient? What additional opportunities will be pursued in 2012 and 2013?

Response:

Yes, FortisBC considers its public school DSM education programs sufficient. FortisBC is presently working collaboratively with FortisBC Energy Inc. to design fulsome, curriculum-based education programs for elementary and high school students. It is expected that the programs will ready for distribution for the 2012/13 school year. For the current 2011/2012 school year FortisBC will continue to sponsor the Destination Conservation (including Environmental Mind Grind), BCSEA Climate Change Showdown and Wildsight programs.

11.2 Please provide examples of the more fulsome offerings for the post- secondary education segment under development.

Response:

FortisBC works in partnership with Okanagan College Residential Construction program to include energy efficiency and conservation training in its “Home for Learning” program. FortisBC has also provided information and sponsorship funding and energy efficient products (lighting, air source heat pumps, EStar appliances) for the construction project. FortisBC intends to continue this partnership.

FortisBC is a member on the Selkirk College School of Renewable Resources Advisory Panel, and provides a guest lecturer for the Integrated Environmental Planning program. FortisBC has also loaned the school technology and equipment.

FortisBC will be sponsoring the goBEYOND Residence Energy Challenge at UBCO in 2011/12.

Furthermore UBCO has asked FortisBC to partner on an energy efficiency and conservation educational out community outreach program. Formal discussions on the scope of the program and partnership are set for early-September, 2011.

11.3 How will FBC support community energy planning specifically? What level of effort is anticipated?

Response:

FortisBC has approached BC Hydro for the rights to use its Community Energy and Emissions Plan (CEEP) QuickStart program to support FortisBC’s community energy planning efforts. As the CEEP program is currently being pilot tested, an agreement has not yet been reached.

If BC Hydro is unable to provide the program by early 2012, FortisBC will approach the BCSEA to create and implement a similar program for FortisBC communities. (BCSEA has expressed interest in providing CEEP programming in the FortisBC service area.)

In the meantime, FortisBC continues to support communities design and implement energy plans. PowerSense employees sit on several community Sustainability Committees, and provide information and input for community sustainability stakeholder meetings.

FortisBC also provides funding for specific energy planning initiatives, for example the City of Rossland householder survey which provided baseline information for the “Village on a Diet” initiative that will launch in the fall of 2011.

12.0 Reference: Exhibit B-1, 2012-13 RRA, 7. Demand Side Management

12.1 Given that the TRC B/C ratio for DSM Total including Portfolio spending is 1.5 (Table 7.0), well above unity, why is FBC not proposing to substantially increase its DSM spending in 2012-13 over 2011 levels?

Response:

Increasing spending by increasing incentive levels further (most programs received an increase in incentive levels in 2011) does not impact the TRC B/C ratio and risks spending additional funds while achieving diminishing returns in program volume.

An increase in the number of programs is also not prudent since FortisBC is already supporting all programs identified in the CDPR with a TRC B/C ratio above unity.

Finally, FortisBC is concerned about the rate impact resulting from demand-side management programs and continues to manage the PowerSense program in a fiscally prudent manner.

13.0 Reference: Exhibit B-2, Long-Term Capacity Balance, p.12

13.1 What is FBC's contingency plan if the Waneta Expansion does not come into service as soon as is expected?

Response:

Please see the responses provided to BCUC IR1 Q255.2 and BCUC IR1 Q255.2.1.

14.0 Topic: 2012 Resource Plan, Market

Reference: Exhibit B-2, Market Assessment, Wholesale Market Curve vs. New Resources Market Curve for Energy, p.16

The graph shows BC Wholesale Market Energy Curve exceeding the BC New Resources Market Energy Curve in about 2031.

14.1 Please confirm that the BC Wholesale Market Energy Curve refers to spot market prices.

Response:

Yes, the BC Wholesale Market Energy curve refers to the forecast average annual spot market price adjusted for delivery to the FortisBC service area.

The curve is based on BC Hydro's Electricity Spot Market Price Forecast for Mid-C from the 2011 Integrated Resource Plan. To translate the BC Hydro Mid-C spot market price forecast into a BC Wholesale Market Energy Curve (in a FortisBC context), additional adders were applied for wheeling through the Bonneville Power Administration system as well as for foreign exchange conversion.

14.2 Does the BC New Resources Market Energy Curve refer to prices for energy available on a long-term basis?

Response:

Yes, the BC New Resources Market Energy Curve assumed long term contractual arrangements. The forecasts are representative of prices that would be available under longer-term energy commitments.

14.3 Please comment on the suggestion that except during temporary market anomalies the BC New Resources Market Energy Curve will always be higher than the BC Wholesale Market Energy Curve because large electricity public utilities in the Pacific Northwest (including BC) are required to have sufficient generation capacity to meet peak demand and therefore typically have excess generation capability that can produce power for sale at the variable cost (mainly fuel) whereas new generation prices include recovery of both variable and capital costs.

Response:

By law, balancing authorities are required to actively reserve certain amounts of capacity as defined by WECC Standard BAL-STD-002-0; these are known as operating reserves. However, these operating reserves must remain within the balancing authority and are not available for sale. Beyond operating reserves there is no legal obligation to hold additional planning reserves. Due to the lack of consistency within the utility industry regarding planning reserves, there is no guarantee that “excess generation” would be available from the larger utilities.

Large public utilities will carry enough generating resources to meet their demand peaks. FortisBC’s peak load hours are typically the same as its Pacific Northwest region neighbours. Therefore, at peak times when FortisBC would need extra capacity to meet its peak loads, the peaking capacity held by neighbouring utilities may not be available.

How the utilities determine their peak loads and hence reserve requirements depends upon the assumptions they make, including, for example, expected load growth net of demand side management and expected water conditions (for hydroelectric generation capacity availability). The assumptions are subject to change with no guarantee that the assumptions prove to ultimately be correct.

Electricity market anomalies arise because of market participants do not accurately anticipate material changes to the supply and/or demand curves associated with the market. The “anomalies” will linger until either supply or demand adjusts, which can sometimes require an extended period of time (for example, until additional generation resources are contracted and commissioned).

History has shown that market “anomalies” can exist for extended periods of time. For example, during the 9-month California energy crisis of 2000, electricity prices were often an order of magnitude higher than they had been during the prior few years. During periods of electrical energy scarcity, the price of the energy should be expected to be well above the marginal cost of generating that energy.

Utilities have been known to assume the availability of generation reserves from neighbouring utilities; in other words, generation reserves are sometimes subject to “double-counting”. For example, if a large utility has excess generation capacity that is presumably available for dispatch into the market, neighbouring utilties will see this as a resource available to them.

However, during times of need (for example, higher than expected load growth) what seemed like excess generation capacity will no longer be excess capacity. Any utility that had planned to rely on that excess capacity would find that it has disappeared from the marketplace just as it is needed most.

Given the above, the price at which electrical energy can be purchased in the market will not necessarily relate to the variable cost of generation. There will be times of electricity scarcity, driving market prices up. The price of BC Wholesale Market Energy will conceivably rise to a point where the New BC Resources Market will be the most economic choice for FortisBC.

15.0 Topic: 2012 Resource Plan

Reference: Exhibit B-2, p.18, 19

FBC's preferred strategy for the short- and medium- term is capacity market purchases and energy market purchases. For the long-term, it is new capacity resource options and new energy resource options. (p.18)

FBC's most attractive new resources for capacity includes 'simple cycle gas turbine' and for energy includes 'combined cycle gas turbine.' (p.19)

15.1 Please confirm that FBC is not proposing to acquire new SCGT or CCGT generation resources in the 2012 ISP.

Response:

FortisBC is not proposing to acquire new SCGT of CCGT generation resources in the 2012 ISP. There are no requests for approval for new generation resources in the 2012 ISP. In the short to medium term, FortisBC plans to continue with market purchases to meet its energy and capacity gaps.

The 2012 Resource Option Report has identified these facilities as some of several preferred capacity or energy options to be considered in the future. The ranking and evaluation criteria were designed as tools to help select resource options that best meet the needs of FortisBC. The ranking does not determine the actual order in which to build projects, but does provide a portfolio of potential resource options that should be considered for development.

At this stage in planning (long-term 30 year horizon), it is not possible to prioritize the preferred resource options that have been identified. As specific needs, capacity gaps, and energy gaps become more apparent in the future, further effort will be required to establish the ultimate priority of the preferred projects.

1.0 Reference: 2010 Resource Options Report, p. 2

"Where appropriate and excepting specific projects for which new cost information has been made available by project proponents, costs drawn from these BC Hydro sources have been escalated to current Canadian dollars using the consumer price index ("CPI")."

1.1 Please identify any other sector specific indices that were considered for use to adjust costs to current dollars?

<u>Response:</u>

No other sector specific indices were used to adjust the costs to current dollars. The consumer price index provides a long-term representation of broad based inflationary effects, and is therefore considered to be sufficient for the purpose of escalating prices for generic resource options.

1.2 Please provide a comparison of CPI with year over year percentage increases to actual capital expenditures and to general rate increases during the past 10 years?

<u>Response:</u>

The following table shows the annual percent change of CPI, FortisBC actual gross capital expenditures and general rate increases for the past 10 years.

Table Celgar IR1 1.2

Year	BC CPI[1] (Annual Percent Change)	Gross Capital Expenditures (Annual Percent Change	FortisBC Yearly Rate Increases
2000	1.8%	3%	4.9%
2001	1.7%	14%	5.0%
2002	2.4%	95%	4.5%
2003	2.2%	-31%	4.3%
2004	2.0%	58%	4.0%
2005	2.0%	32%	3.4%
2006	1.7%	-3%	5.9%
2007	1.8%	31%	3.3%
2008	2.1%	-22%	3.4%
2009	0.0%	1%	5.3%
2010	1.3%	26%	7.1%

[1]BC CPI as reported by Statistics Canada.

2.0 Reference: 2012 Long Term Demand-Side Management Plan, Section 3.1, p. 12, Review of 2011 DSM Plan, and Section 3.2.1, p.l3, Updated Avoided Power Purchase Costs, and Conservation and Potential Demand Review Report, p. 6, 2011 DSM Plan, Table 5.2.1

"The measure benefits were based on unit savings and measure life, sourced from the CPDR report, multiplied by the provincial long-run avoided power purchase costs of $154.15 per MWh."

"The resulting blended cost of $104.32 per MWh, shown in Table 3.2.1 below, is used to determine the benefits of the programs."

"For this study, BC Hydro's long-term avoided costs are used to value energy, peak demand, and transmission and distribution savings. Avoided costs for energy measures are $154/MWh in levelized cost terms (2010 dollars)."

2.1 Please provide the calculation of the long-run avoided power purchase cost of $154.15 found in the 2012 DSM plan, p. 13, Table 3.2.1?

Response:

Please refer to the response to BCOAPO IR1 Q64.3.

2.2 Please comment on whether or not the provincial long-run avoided power purchase costs of $154.15 per MWh or a blended cost was used to determine the benefits of the programs in the 2011 DSM plan? If there has been a change to a blended cost from an avoided supply cost in the 2012 DSM plan, please explain and justify the change?

Response:

The 2010 CDPR study and the 2011 DSM Plan filing used the $154.15 avoided cost figure. The 2012 long-term DSM Plan and 2012-13 CEP updated the blended avoided cost figure shown in Table 3.2.1 (as corrected in Errata 2). Both figures are a blended avoided supply cost.

Please also refer to the response to BCUC IR1 Q296.1.

2.3 Please file the DSM Regulation and confirm that section 4(3) of the DSM regulation states:

"In determining whether a demand-side measure of a bulk electricity purchaser is cost-effective, the commission must consider the benefit of the avoided supply cost to be the authority's long-term marginal cost of acquiring new electricity to replace the electricity sold to the bulk electricity purchaser and not the bulk electricity purchaser's cost of purchasing electricity from the authority."

Response:

The Demand-Side Measures Regulation is attached to these responses as Celgar IR1 Appendix 2.3. FortisBC confirms that section 4(3) of the DSM Regulation is as stated in the question.

2.4 Is it FortisBC's opinion that Section 4(3) of the DSM regulation requires the use of a blended cost as per Table 3.2.1 rather than the provincial long-run avoided supply cost? If so, please explain why Section 4(3) should not be interpreted so as to use "avoided supply cost to be the authority's long-term marginal cost" to determine the benefits of the FortisBC DSM programs?

Response:

Please refer to the response provided to BCUC IR1 Q296.1

2.5 Please file any legal opinions that FortisBC may have obtained that consider the DSM regulation?

Response:

The Company does not understand how the question is related to the preamble. To the extent that the question is asking for legal advices and opinions provided to the Company, any legal advice or opinions are privileged.

2.6 Please confirm that if a bulk electricity purchaser did not purchase power from any source other than BC Hydro the avoided supply cost would be the same for BC Hydro and the bulk electricity purchaser? Please explain why, from a policy perspective, using the same avoided supply cost for all bulk electricity purchasers and BC Hydro is not the preferred approach to determine DSM programs?

Response:

FortisBC agrees that if a bulk electricity purchaser did not purchase power from any source other than BC Hydro, the avoided supply cost would be the same for BC Hydro and the bulk electricity purchaser

FortisBC supports the use of the blended avoided supply cost prescribed by regulation since it more accurately reflects the economic circumstances of the bulk electricity purchaser than simply using the same avoided supply cost for all bulk electricity purchasers.

2.7 Please provide details, including rate sheets where applicable, of the industrial programs offered by BC Hydro with the industrial programs offered by FortisBC, including the TRC ratio, utility costs, and program incentives?

Response:

BC Hydro does not file rate sheets on any of its DSM programs. The FortisBC Schedule 90 DSM Tariff is a framework under which its DSM programs operate.

Comparative details on specific industrial programs are provided in subsequent Celgar information requests.

2.8 Please compare and explain any differences in financial incentives to customers of BC Hydro and FortisBC? Is it reasonable for each utility to offer different incentive levels? Is so, please explain why?

Response:

Comparative detail is provided in responses to specific program IRs that follow.

It is reasonable for utilities to offer DSM incentives based on their specific business circumstances.

2.9 Does FortisBC benchmark its DSM programs with those of BC Hydro? Please file any benchmarking reports prepared by FortisBC? If it does not, please prepare a bench marking summary report.

Response:

FortisBC does not formally benchmark its DSM programs with BC Hydro or any other utility. A summary table of the BC Hydro Industrial Partners Program, including the equivalent FortisBC offer, follows:

Table Celgar IR1 2.9

Category	**Summary of BC Hydro Category Initiatives** Eligibility varies based on $ billed or GW.h thresholds or industry segment	**FortisBC Industrial Program** Available to all industrial customers
Plan	• Industrial Energy Manager, • New Plant Design, • Energy Management Assessment, • Energy Manager for Industrial Associations	Industrial Efficiency Program • Trades Training Program
Discover	• Customer Site Investigation or Plant-wide Audit, • End-Use Assessment or Feasibility Study, • End-Use Bundles (key systems) • Mechanical Pulping Bundle	Industrial Efficiency Program • Free walk-through audit • Comprehensive plant/process audit/study subsidy
Upgrade	• Project incentive for efficiency upgrade • Conservation Rates	Industrial Efficiency Program • Custom option incentive
Support	• Employee Energy Awareness, • Monitoring Targeting and Reporting, • Metering and instrumentation loans, • PowerSmart Partner Recognition	Energy Management Information system • ISO 50001 pilot • Project sub-metering

Please also see the response to Celgar IR1 Q2.15.

2.10 Did the EES Conservation and Demand Potential Review use the blended cost or the “avoided supply cost to be the authority’s long-term marginal cost” in the study? What benefit value was used in the cost-effectiveness tests?

Response:

The 2010 CDPR study by EES used the blended avoided cost of $154.15/MWh to determine DSM benefits. Please also refer to the response to BCOAPO IR1 Q64.4 for the derivation of that figure.

2.11 Since FortisBC is a customer of BC Hydro are BC Hydro’s DSM programs available to FBC customers on a flow-through basis?

Response:

No, FortisBC customers do not qualify for BC Hydro DSM programs.

2.12 Is FortisBC aware of any other bulk electricity purchaser that has access to BC Hydro Power Smart programs?

Response:

FortisBC does not know what is meant by “any other bulk electricity purchaser”, but understands that the City of New Westminister has access to some BC Hydro PowerSmart programs.

2.13 Does the City of New Westminister have the same DSM programs or similar programs of those of BC Hydro? Does the City of New Westminister use the services of BC Hydro to design, deliver or evaluate DSM programs? What specific DSM programs does the City of New Westminister make available to its industrial customers?

Response:

FortisBC believes that the City of New Westminster electric utility customers have access to a limited menu of BC Hydro DSM programs. FortisBC understands that the City of New Westminster has no industrial customers.

2.14 Is FortisBC willing to provide its industrial customers with the same programs that BC Hydro is willing to provide its industrial customers? If not, why not? If not, is FortisBC willing to support policies that will ensure the design and delivery of the same DSM programs to all customers in BC? For example, does FortisBC support establishing an entity other than FortisBC to administer, design, and evaluate DSM programs to be delivered to its customers?

Response:

FortisBC considers programs provided by other utilities, including BC Hydro, when designing programs, but does not necessarily copy them. As stated in response to Celgar IR1 Q2.8, it is reasonable for utilities to offer DSM incentives based on their specific business circumstances.

FortisBC does not support the notion of an entity other than itself administering DSM programs for FortisBC customers.

2.15 As part of the "customized assistance" for industrial customers, is FortisBC willing to provide financial incentives that are comparable to those BC Hydro provides to its customers for DSM projects? If not, please explain why not? Please identify DSM programs in the industrial sector that are being offered by BC Hydro that are currently not feasible under the FortisBC current funding levels?

Response:

Please see the response to Celgar IR1 Q2.14. Any customer proposal, including a proposal similar to a BC Hydro program, would be evaluated on the basis of whether it provides cost-effective, demonstrable energy savings within the guidelines of FortisBC's Electric Tariff and the DSM Regulation.

3.0 Reference: EES Conservation and Demand Potential Review Report, Exhibit B-1-2, p. 5

"Other features such as measure load shape, operation and maintenance costs, and non-energy benefits are also important for measure definition."

3.1 Please comment on whether or not the measure load shape and the load factor to be served by the utility are significant to a potential assessment?

Response:

The measure load shape and the associated savings can be important in a potential assessment in valuing capacity-related electricity savings.

The 2010 CDPR used an annual average levelized avoided cost to value the energy savings.

The load shapes were used in the 2010 CDPR to calculate peak demand savings from the energy efficiency measures.

3.2 Please comment on the significance of the measure load shape and the load factor to the total resource cost test, and illustrate with a TRC calculation?

Response:

Please see the response to Celgar IR1 Q3.1. Load shapes were not used in the CDPR calculation of energy benefits, and therefore did not impact the TRC calculation.

4.0 Reference: EES Conservation and Demand Potential Review Report, Exhibit B-1-2, p. 87:

"The base year for industrial sector consumption is calculated using the 2009 energy forecast for rate schedules 30, 31, and 33 and the Tolko sawmill (wholesale customer)."

4.1 Please adjust the base year by using the 2009 energy forecast for the industrial sector consumption assuming that Celgar has a GBL of 1.5 MW with a 95% load factor?

Response:

The base year would be adjusted such that Pulp & Paper consumption was changed from 16.5 GWh to 328.1 GWh.

4.2 Please calculate the technical, achievable and program achievable energy potential for the industrial sector using the adjusted base year and make any other revisions to the study necessary for the adjusted base year, including the following revised tables and figures: Table 38, Table 41, and Table 45 and figures: Figure 53?

Response:

In order to be considered as conservation, any DSM related activity must result in reduced load on the utility. Activities that reduce the plant load of a self-generating customer, which simply allows that customer to increase power sales without a corresponding reduction in FortisBC load, would not be included in the conservation totals for DSM purposes.

The revised tables and figure are as follows:

Table 38
Summary of Energy Efficiency Technical Potential

		Energy Efficiency	
Sub-Sector	2030 GWh from End-Use Model	Total Technical Potential GWh	Total Potential as % of 2030 Forecast
Pulp and Paper	328.1	99.2	30%
Mining	9.1	1.1	12%
Food & Beverage Manufacturing	13.9	3.8	27%
Wood Products	90.1	15.1	17%
Fruit Packers and Storage	8.7	3.0	34%
Miscellaneous Manufacturing	69.2	7.4	11%
Total MWh	519.1	129.7	25%

Table 41
Summary of Achievable Energy Efficiency Potential – Technical

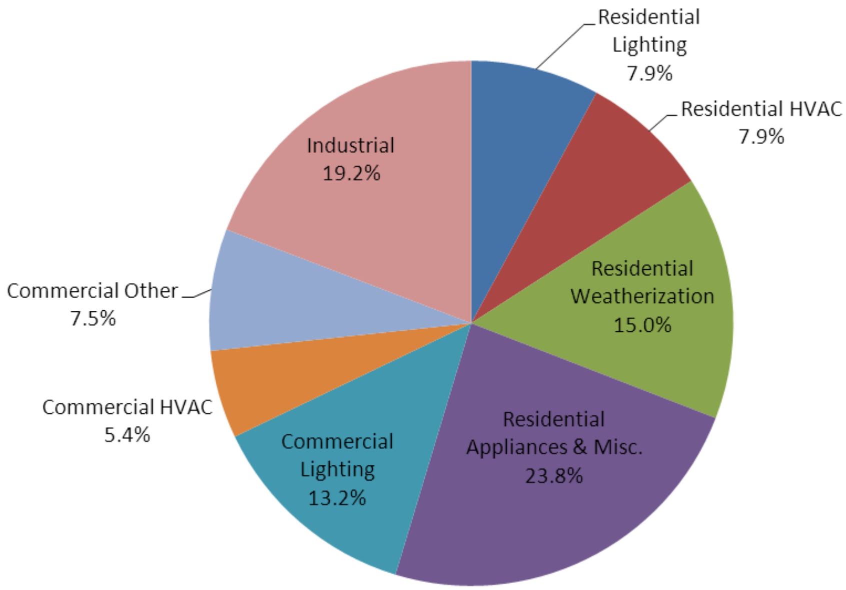
		Energy Efficiency	
Sub-Sector	2030 GWh from End-Use Model	Total Achievable Potential GWh	Total Potential as % of 2030 Forecast
Pulp and Paper	328.1	71.9	22%
Mining	9.1	0.9	10%
Food & Beverage Manufacturing	13.9	2.7	20%
Wood Products	90.1	12.2	14%
Fruit Packers and Storage	8.7	2.6	30%
Miscellaneous Manufacturing	69.2	5.9	8%
Total MWh	519.1	96.2	19%

Table 45
Summary of Energy Efficiency Potential

		Technical		**Achievable**	
Sub-Sector	**2030 GWh from End-Use Model**	**Total Technical Potential GWh**	**Total Potential as % of 2030 Forecast**	**Total Achievable Potential GWh**	**Total Potential as % of 2030 Forecast**
Pulp and Paper	328.1	99.2	30%	71.9	22%
Mining	9.1	1.1	12%	0.9	10%
Food & Beverage Manufacturing	13.9	3.8	27%	2.7	20%
Wood Products	90.1	15.1	17%	12.2	14%
Fruit Packers and Storage	8.7	3.0	34%	2.6	30%
Miscellaneous Manufacturing	69.2	7.4	11%	5.9	8%
Total	519.1	129.7	25%	96.2	19%

The updated Figure 53 shows that Industrial potential is 19.2 percent of the total. Without the Base year adjustment, Industrial potential is 4.8 percent of the total.

Figure 53
Energy Efficiency Achievable Potential Summary



4.3 Please identify all cost-effective DSM programs for the industrial sector using the adjusted base year? Please compare the cost-effective DSM programs using the base year and the adjusted base year for the industrial sector programs?

Response:

Table 4.3A lists all the cost-effect DSM programs for the adjusted base year. The analysis assumes that Celgar is not selling its self generation despite having a GBL of 1.5. DSM potential and any associated DSM expenditures must result in conservation (reduced load) to the utility, and hence a benefit to all rate-payers. It cannot be used to make more power available for a self-generating customer to sell.

Table 4.3A
Base Level Savings, Achievable Potential
with Updated Pulp & Paper Loads

Measure Type	Conservation Measure	Potential Savings MWh	Summer Demand Savings (kW)	Winter Demand Savings (kW)
Compressed Air	Air Compressor Demand Reduction	2,186	349.8	349.8
Compressed Air	Air Compressor Equipment2	1,894	303.0	303.0
Compressed Air	Air Compressor Optimization	5,285	845.6	845.6
Lighting	HighBay Lighting 1 Shift	395.0	63.2	71.1
Lighting	HighBay Lighting 2 Shift	292.4	46.8	52.6
Lighting	HighBay Lighting 3 Shift	1,842	294.8	331.6
Lighting	Efficient Lighting 1 Shift	392.1	62.7	70.6
Lighting	Efficient Lighting 2 Shift	280.5	44.9	50.5
Lighting	Efficient Lighting 3 Shift	1,879	300.6	338.2
Lighting	Lighting Controls	606.5	97.0	109.2
Motors	Motors:Rewind 20-50 HP	306.7	49.1	49.1
Motors	Motors:Rewind 51-100 HP	195.7	31.3	31.3
Motors	Motors: Rewind 101-200 HP	289.0	46.2	46.2
Motors	Motors: Rewind 201-500 HP	239.1	38.3	38.3
Motors	Motors: Rewind 501-5000 HP	372.4	59.6	59.6
Fans	Efficient Centrifugal Fan	1,038	166.1	166.1
Fans	Fan Energy Management	1,736	277.8	277.8
Fans	Fan Equipment Upgrade	5,039	806.3	806.3
Fans	Fan System Optimization	8,145	1303	1303
Pumps	Pump Energy Management	2,105	336.9	336.9
Pumps	Pump Equipment Upgrade	5,942	950.7	950.7
Pumps	Pump System Optimization	6,266	1003	1003
Transformers	Transformers-Retrofit	514.8	72.1	72.1
Transformers	Transformers-New	499.5	69.9	69.9
Belts	Synchronous Belts	1,859	296.9	296.9
Hi-Tech	Clean Room: Change Filter Strategy	32.7	4.6	4.6
Hi-Tech	Clean Room: Clean Room HVAC	21.8	3.0	3.0
Hi-Tech	Clean Room: Chiller Optimize	34.1	4.8	4.8
Food Processing	Food: Cooling and Storage	475.7	95.1	90.4
Food Storage	Food: Refrig Storage Tuneup	257.2	51.4	48.9
Paper	Paper: Efficient Pulp Screen	1,134	158.7	158.7
Paper	Paper: Premium Fan	2,222	355.5	355.5
Paper	Paper: Premium Control Large Material	2,073	331.7	331.7
Material Handling	Material Handling2	1,535	245.6	245.6
Material Handling	Material Handling VFD2	6,560	1050	1050
Wood	Wood: Replace Pneumatic Conveyor	2,856	456.9	456.9
Food Storage	Fruit Storage Refer Retrofit	2,036	407.1	386.8

Table 4.3A continued
Base Level Savings, Achievable Potential with Updated Pulp & Paper Loads

Measure Type	Conservation Measure	Potential Savings MWh	Summer Demand Savings (kW)	Winter Demand Savings (kW)
Food Storage	CA Retrofit -- CO2 Scrub	127.7	25.5	24.3
Food Storage	CA Retrofit -- Membrane	82.3	16.5	15.6
Food Storage	Fruit Storage Tuneup	688.5	137.7	130.8
Plant Energy Management	Plant Energy Management	12,234	1713	1713
Energy Project Management	Energy Project Management	20,331	2847	2847
Integrated Plant Energy Management	Integrated Plant Energy Management	26,435	3701	3701
Mining Process	Grinding Optimization, Improved Flotation Cells and O&M	943.1	150.9	433.8

Table 4.3B compares the Base level achievable potential to the achievable potential with the adjusted Base Year consumption.

Table 4.3B
Comparison of Base Level and Adjusted Base Level Savings Achievable Potential

	Potential Savings MWh	Summer Demand Savings (kW)	Winter Demand Savings (kW)
Base Level	27,674	4,453	4,715
Adjusted Base	129,674	19,670	20,030
Difference	102,000	15,217	15,315

4.4 Please confirm that a high Benefit/Cost ratio for the industrial sector provides FortisBC with an opportunity to pursue programs with a Benefit/Cost ratio less than unity in the residential and commercial sector? If not confirmed, please explain why?

Response:

Not confirmed. While some measures in the Residential or Commercial sectors have a BCR near 1.0, they are bundled with other measures in the same program or sector in order to pass the TRC B/C test. The residential and commercial sector B/C ratios shown in Table 3.2.2 are robust on their own merits.

4.5 Please describe in detail the programs that may have been pursued by FortisBC in the industrial sector if the avoided supply cost of the authority was used of $154.15 instead of the blended cost of $104.32 was used to determine the programs?

Response:

Please refer to the response to Celgar IR1 Q4.3 above. Table 4.3A provides a complete list of cost-effective measures, based on the $154.15/MWh avoided cost as used in the original 2010 CDPR. The industrial programs that would be been pursued in this scenario, or any other scenario, are dependent upon the DSM proposals brought forward by customers.

4.6 Please provide all algorithms used to calculate the program incentives to be paid to customers in the industrial sector that implement DSM efficiency measures?

Response:

The general algorithm is as follows:

DSM incentive = Annual kWh savings (kWh) x program/measure incentive rate (□/kWh)

The DSM incentive payment is capped as described in response to Celgar IR1 Q6.14 and subject to the Tariff.

4.7 Does the blended cost of $104.32 determine the program incentives to be paid to customers in the industrial sector that implement DSM efficiency measures? If there are other factors that determine incentives, please provide details of the calculations?

Response:

The long-term avoided cost is a cap on any DSM incentive to be paid as described in the response to Celgar IR1 Q6.14. Other caps on DSM incentives are also provided in that response.

4.8 Are the FortisBC programs and financial incentives to be paid to customers increasing or decreasing with the use of $104.32 instead of $154.15 for the avoided supply cost? Is the gap between the financial incentives paid to customers by BC Hydro and by FortisBC increasing over time? Please explain?

Response:

A change in the avoided supply cost does not directly impact the DSM incentives paid to customers, but can result in a cap to the DSM incentive as described in the response to Celgar IR1 Q64.1. FortisBC cannot comment on whether a gap exists, or if a gap exists whether it is increasing or decreasing, between FortisBC and BC Hydro industrial DSM incentives.

5.0 Reference: EES Conservation and Demand Potential Review, p. 11

"FortisBC has been active in helping their customers become more energy efficiency [efficient] through their PowerSense program since 1989."

5.1 Please comment on all activities in the past year and activities that are planned for the test period that have been or will be undertaken by FortisBC to assist Celgar to achieve energy efficiency?

Response:

There are no DSM activities underway in the current year, nor planned in the test period. Until the current regulatory proceedings involving Celgar and FortisBC are resolved, it is unclear whether, or the extent to which, DSM incentives can be paid by FortisBC to Celgar.

6.0 Reference: 2012-2013 Capital Expenditure Plan, p. 124, Table 7.3, and p. 125, Section 7.3.2

"FortisBC will offer customized assistance and financial incentives for industrial customers to achieve increased efficiency. This will include free initial assessment of energy use, and where a more detailed assessment is required, 50 percent of an approved study's costs. FortisBC also will provide rebates towards the incremental cost of efficiency measures compared to standard "baseline" construction (the rebate entitlement is based on estimated annual kWh savings, with the maximum rebate calculated to achieve a two-year payback on incremental cost)."

"Free Initial Assesment": Assessing energy savings in a facility such as the Celgar pulp mill with up to 50 MW of potential load resulting from over 800 motors pumps, compressors and fans is a complex review."

6.1 Please explain why there are no industrial efficiency measures forecast for Celgar during the test period?

Response:

Please see the response to Celgar IR1 Q5.1.

6.2 If the Celgar savings and costs are included in the column "Industrial Efficiency", please provide the details of calculations for the Celgar savings and costs?

Response:

Please see the response to Celgar IR1 Q5.1.

6.3 Please identify all efficiency programs and any specific measures that are forecast for Celgar beyond the test period?

Response:

FortisBC has not fully developed, nor filed, its DSM Plan beyond the test period. Please also see the response to Celgar IR1 Q5.1.

6.4 Please comment on the significance of the current regulatory proceedings to the assessment of energy efficiency measures at the mill in Castlegar?

Response:

The current regulatory proceeding seeks approval of, among other things, the Company's DSM expenditures. The DSM program, as discussed in the preamble above, is available to all industrial customers where cost-effective energy efficiency initiatives would decrease the load that the Company is required to supply to those customers. DSM expenditures are not intended to incent customers to reduce consumption in order to enable higher electricity sales. The fundamental premise behind the DSM program is to cost-effectively conserve energy.

6.5 What is the maximum amount that FortisBC provides to an industrial customer for study costs beyond the free assessment?

Response:

The DSM incentive cap information is provided in the response to Celgar IR1 Q64.1.

6.6 What is the maximum amount that BC Hydro provides to an industrial customer for study costs?

Response:

The table below is a summary of BC Hydro guidelines (published on BC Hydro's web-site) for funding of industrial studies. As indicated in the table, the maximum funding for Plant-Wide Audits is $40,000, for End-Use Assessments $5,000. For other types of studies no maximums are provided.

INITIATIVE	WHAT IS IT?	ELIGIBILITY	KEY OFFER
Customer Site Investigation	A high-level assessment of an entire facility.	Customers who use between $50,000 and $1 million of electricity per year	100% funding.
Plant-Wide Audit	A high-level assessment for larger plants.	Customers who use more than $1 million of electricity per year	75% to 100% funding up to $40,000.
End-Use Assessment	A high-level assessment of a specific system.	Systems that use more than 1GWh per year.	100% funding up to $5,000.
Energy Efficiency Feasibility Study	An in-depth investigation of solutions in a single system.	Systems that use more than 1GWh per year.	75% to 100% funding.
End-Use Bundles	An integrated stream of offers for the six most common industrial systems.	Varies by system.	Major funding to study and upgrade inefficient systems.
Mechanical Pulping Bundle	An integrated stream of offers for mechanical pulping mills.	Pulp and paper customers.	Major funding to hire an MP energy manager to study and upgrade your mill.

6.7 Does Fortis deduct the 50% funding that is provided for the assessment against any rebates that are provided for the capital cost of energy saving measures identified in the study? Please explain.

Response:

If FortisBC pays more than $1,500 for consulting or study services, any incentive amount that may be payable to that Customer will be reduced by the FortisBC contribution for these services.

6.8 Please attach BC Hydro's "Energy Efficiency Feasibility Study Brochure".

Response:

The brochure is provided as Celgar IR1 Appendix 6.8.

6.9 Please make such inquiries with BC Hydro as are necessary so as to confirm the following:

6.9.1 BC Hydro provides 75% of funding for energy feasibility studies and that it is not deducted from future rebates that a customer would receive for implementing a power saving project; and

Response:

Confirmed.

6.9.2 BC Hydro provides the remaining 25% of funding for energy feasibility study if the project is implemented and that it is not deducted from future rebates that a customer would receive for implementing a power saving project.

Response:

Confirmed.

6.10 For the following questions, please assume an industrial customer had a project with 42,000 MWh in annual savings, could demonstrate a persistence of over 10 years, and needed an incentive of $7,500,000 to facilitate the project's implementation.

6.10.1 Please describe how the FortisBC customized program would facilitate such a project, that could clearly be facilitated within the BC Hydro service area for its large customers?

Response:

An process audit would be recommended and co-funded in order to provide greater certainty on the project energy savings and measure life. FortisBC would need the total project cost and an estimate of the portion of the project cost strictly related to energy in order to determine whether the project met the TRC cost-effectiveness test prescribed in the DSM regulation.

6.10.2 Would this project be more cost-effective than resource options, given the expected long-term marginal cost for incremental power for FortisBC?

Response:

DSM measures are not evaluated for cost-effectiveness by comparing the utility cost to a utility's long-term marginal cost of power. They are evaluated for cost-effectiveness using the TRC test as prescribed in the DSM regulation. The total cost of the measure in this theoretical example is not known, so the TRC B/C ratio cannot be calculated.

6.10.3 Should FBC not be exhausting these types of projects prior to proceeding with planning for incremental capacity projects?

Response:

FortisBC is not certain what "these types of projects" are, but is committed to supporting all cost-effective DSM as prescribed by the DSM regulation.

6.11 Please provide the ratio of plan targets by sector to achievable potential by sector for the residential, commercial, and industrial sectors?

Response:

Please see Table Celgar IR1 6.11 below, wherein the Ratio column expresses the 2012-13 DSM Plan savings by the CDPR identified achievable potential in per cent by sector.

Table Celgar IR1 6.11

Sector	2012 & 2013 Plan target (GWh)	Total Achievable Potential (GWh)	**Ratio**
Residential	33	479	**6.9%**
Commercial	25.4	201	**12.6%**
Industrial	5.1	27.8	**18.3%**

6.12 Please explain what is meant by: "customized assistance"? Are the financial incentives "customized" for each customer? If so, please explain the criteria used to determine the financial incentives?

Response:

A custom option incentive approach is used for industrial customers to reflect their relatively complex needs and large energy savings. The approach allows FortisBC to take variables such as measure life and persistence into consideration so that customers will be motivated to implement a project while at the same time acquiring the savings at the least cost to other rate payers. Please also see the response to Celgar IR1 Q6.14.

6.13 Based on the 9,280 MW.h savings in Table 7.3, excluding the EMIS savings, please provide the detailed description of and calculation for the $613,000 cost?

Response:

In the 2011 Approved Plan, the costs and savings excluding EMIS, were tabulated as follows:

Table Celgar IR1 6.13

Component	Energy Savings	Incentive Rate	Incentive Cost	Program Admin	Total Cost
	MWh	$/MWh	$000s		
Industrial Efficiency	1,840	$100	$184	$47	$231
Celgar	7,440	$50	$372	Included	$372

The Celgar project savings and incentive commitment were based on discussions held in 2010 when the prevailing DSM incentive level was 5 cents per kWh, or $50/MWh.

6.14 Is the rebate entitlement to industrial customers, based on the following parameters:

> Unless otherwise stated, the rebate entitlement is based on 10¢ per estimated annual kW.h savings, with the maximum rebate calculated to achieve a two-year payback on incremental cost or 50% of installed cost, whichever is less.

Response:

FortisBC does not understand the term “rebate entitlements”. DSM incentives for industrial customers are based on 10¢ per estimated annual kW.h savings, capped to the lesser of:

i. the Company’s long-term avoided power purchase costs,

ii. 50% of installed Measure cost for existing construction,

iii. 100% of incremental cost for new construction, or

iv. The amount sufficient for the Customer to achieve a two-year payback.

6.15 Does FortisBC include the persistence of the “annual kW.h savings (from questions 6.14) in any of its benefits calculations.

Response:

Yes, FortisBC does consider the persistence or effective measure life (EML) of a project in its benefit calculations. In general the value of an energy saving measure or project, in terms of $/MWh, is calculated by dividing the cost of the project by the present value of the energy saved over the EML.

6.16 In the calculation of the rebate entitlement if annual kW.h savings persist for 10 years does FortisBC provide recognition for this to its customer. If not, why not?

Response:

The persistence of the measure is used when calculating the benefits in the TRC B/C ratio. A longer measure life will provide larger benefits in the TRC calculation and therefore make it more likely that the measure will be considered cost-effective.

6.17 Is the "avoided supply cost" used in the determination of the program incentive and the incentive for the efficiency measure? If so, how?

Response:

The "avoided supply cost" is used a cap on the maximum DSM incentive. Please also see the response to Celgar IR1 Q6.14.

6.18 Please provide the evidence to support each element of the above formula for determining the rebate entitlement: the 10 cents per kW.h savings, the two-year payback on incremental cost, and 50% of installed cost?

Response:

FortisBC views the 10 cents per kW.h is a reasonable starting point for incentive calculations that is roughly equal to the avoided supply cost for the utility. The DSM incentive caps cited above are necessary to ensure that FortisBC customers as a whole are receiving value for DSM investments by placing reasonable limits on the amount of incentive paid.

6.19 Please provide the detailed calculations of the energy savings of 7,440 MWh and the costs of $372,000 for Celgar found in Table 7.3? Is the $372,000 to be provided as a financial incentive to the customer, in this case, Celgar?

Response:

The energy savings for the specific energy-efficiency projects proposed by Celgar in 2010, totalled approximately 15 GWh. As provided in Schedule 90, the plan energy savings and nominal incentive amount were split, and only the first half were put in the 2011 DSM Plan.

Refer to the response to Celgar IR1 Q6.13 for the calculation of the financial incentive.

In order to be considered as conservation, any DSM related activity must result in reduced load on the utility. Activities that reduce the plant load of a self-generating customer, which simply allows that customer to increase power sales without a corresponding reduction in FortisBC's load would not be included in the conservation totals for DSM purposes.

6.20 Please comment on whether or not the BC Hydro financial incentive to a customer on a DSM project that delivers 7,440 MWhs of annual savings would be approximately $2,232,000 ($30/MWh times 7,440 MWh times 10 years) as compared to the FortisBC financial incentive of $372,000?

Response:

Based on published information from BC Hydro's web-site, for projects over $1 million, up to 75% incentive is available; below $1 million up to 100% incentive is available (based on the calculated savings at a rate of $30.9/MWh (NPV of $45/MWh for a project with a10 year persistence). The incentive amount cannot exceed the cost of the project.

Large project incentives would require approval by BC Hydro Senior Management and DSM budget limitations may apply.

6.21 Please provide references to BCUC Orders or Decisions that approved the savings and costs listed on Table 7.3?

Response:

Only the DSM costs and savings in the 2011 column were approved under BCUC Order G-195-10. The 2012-13 figures are under consideration in this filing.

6.22 Please compare the forecast of plan expenditures by BC Hydro and FortisBC for the test period and beyond, including a comparison of the ratio of plan expenditures by sector to the load forecast by sector?

Response:

FortisBC has only filed DSM figures for the test period 2012-13. DSM figures beyond the test period are not yet fully developed at this time.

FortisBC is unable to obtain a DSM forecast for BC Hydro, although FortisBC understands that BC Hydro intends to file a DSM plan in the fall of 2011.

Earlier this year the provincial government commissioned an independent review of the authority's proposed rate increases, the report[1] of which was released August 11th, and included the following Recommendation No.54:

> "Re-evaluate its various energy conservation programs to reduce the overall costs to ratepayers while still achieving value for money."

6.23 Please describe the project that FortisBC has identified at 7,440 MWh in savings? Has Celgar undertaken this project? Has FortisBC received a proposal from Celgar on this project?

Response:

Based on discussions undertaken by FortisBC's Key Account Manager, two DSM projects were being considered by Celgar in the spring of 2010: new generation screens in pulp cleaning cyclones, and systematic replacement of pumps stations with more efficient pumps equipped with variable speed drives.

It is not known whether Celgar has undertaken these projects. No formal proposal has been received on these specific projects. Furthermore, until the current regulatory proceedings involving Celgar and FortisBC are resolved, it is unclear whether, or the extent to which, DSM incentives can be paid by FortisBC to Celgar.

6.24 Please assume a company has a three year payback threshold to implement a project and the project had a capital cost of $8,000,000 with combined annual savings of energy and other savings of $1.93 million per year. Would this project meet the payback criteria to be executed with a FortisBC incentive of $372,000? Would this project meet the payback criteria to be executed with a $2,232,000 incentive from BC Hydro. Please explain?

Response:

Since the question implies that non-energy savings exist, approval of this theoretical project is not certain since the TRC cannot be calculated. Also, the FortisBC DSM incentive cannot be calculated without knowing the annual kWh savings resulting from this theoretical project.

[1] http://www.newsroom.gov.bc.ca/downloads/bchydroreview.pdf

For a project of this magnitude both BC Hydro and FortisBC would use the similar approach in that they would require a proper business case to be submitted and the benefits to both the customer and utility would be analyzed. BC Hydro, just as FortisBC, will not provide large incentives without due diligence and such incentives need to be approved by BC Hydro senior management and are subject to DSM budget limitations. Both companies would presumably require extensive credit reviews and customers may be required to provide a letter of credit in the amount of the incentive to the utility.

At both BC Hydro and FortisBC, projects of this magnitude involve further analysis and assessment. FortisBC made an assessment that $372,000 was the budgeted incentive, based on the information and DSM incentive rate available at the time, but subject to the necessary due diligence and caps set out in Rate Schedule 90. FortisBC cannot be certain of any incentive BC Hydro would have awarded for this theoretical project because it would have depended on its assessment of the business case and budget limitations.

7.0 Reference: EES Conservation and Demand Potential Review, p. 46

" The methodology for forecasting peak demand by end use was first to calculate load factors for each type of industry …"

7.1 What specific load factor was used for the pulp and paper sector?

Response:

A winter peak demand load factor of 70 percent was used for the pulp and paper sector. This load factor is based on the annual energy, the end-use energy split (pumps, compressors, fans, lighting etc) according to regional studies, and load factors by end-use for the specific industry. This load factor includes an assumed coincident factor with the utility's peak demand (load factor plus coincident peak demand load factor). However, if the pulp and paper customer's peak demand is 100 percent coincident with the utility's system, then the 70 percent load factor would represent the customer's actual winter load factor.

8.0 Reference: 2012 Long Term Demand-Side Management Plan, p. 14, Table 3.2.2 and EES Conservation and Demand Potential Review, p. 100

"A bulk of the savings comes from measures with low levelized cost of $0.03-$0.04/kWh."

8.1 Please comment on whether or not the Benefit/Cost ratio in Table 3.2.2 is on a TRC basis? Is the Benefit/Cost ratio in the table the TRC ratio?

Response:

The Benefit/Cost ratio in Table 3.2.2 is on a TRC basis. The Benefit/Cost ratio in the table is the TRC ratio.

8.2 In tabular format, please provide the aggregate levelized costs, the utility levelized costs, and the measure costs for the residential, commercial, and industrial sectors? In tabular format, please provide the TRC ratio, together with the benefits and costs, by program for all programs effective during the plan period, and for the program portfolio in the residential, commercial, and industrial sectors?

Response:

The table below provides the aggregate levelized total resource cost and the utility levelized cost by sector for the 2012-2013 DSM plan.

Table Celgar IR1 8.2a

Sector	Aggregate Levelized Total Costs ($/MWh)	Utility Levelized Costs ($/MWh)
Residential	70.1	30.5
Commercial	67.1	27.1
Industrial	26.4	12.1
Total	65.4	27.7

The following table is for the year 2012. This table would be very similar for 2013. Beyond 2013 the detailed DSM plan is not developed.

1 **Table Celgar IR1 8.2b**

Sector	Program	TRC Benefit/ Cost ratio	Benefits ($)	Costs ($)
Residential	Building Envelope	1.4	4,740,000	3,380,000
Residential	Heat Pumps	1.1	3,500,000	3,200,000
Residential	New Home	1.2	103,000	87,900
Residential	Lighting	1.8	1,160,000	635,000
Residential	Appliances	2.8	1,770,000	640,000
Residential	Electronics	3.1	208,000	67,000
Residential	Water Heating	3.4	777,000	223,000
Residential	Low Income	1.6	1,800,000	1,130,000
Residential	Behavioural	4.9	1,390,000	280,000
Residential	Sub-Total	1.6	15,400,000	9,650,000
Commercial	Lighting	1.6	4,790,000	3,070,000
Commercial	BIP	1.8	3,730,000	2,100,000
Commercial	Computers	2.3	297,000	131,000
Commercial	Municipal	1.1	839,000	782,000
Commercial	Irrigation	1.9	986,000	179,000
Commercial	Sub-Total	1.7	10,600,000	6,260,000
Industrial	Industrial Efficiency	0.8	129,000	159,000
Industrial	Industrial EMIS	5.5	1,560,000	283,000
Industrial	Sub-Total	3.8	1,690,000	442,000
All	Grand Total	1.7	27,800,000	16,400,000

2

9.0 Reference: EES Conservation and Demand Potential Review, p. 127, Table 68

9.1 Please provide a similar table to Table 68 for BC Hydro that compares potential estimates by sector? In tabular format, please present the potential estimates, plan targets, and the sector percentage of total load for BC Hydro and FortisBC?

<u>Response:</u>

FortisBC does not have similar information for BC Hydro and therefore is unable to provide the requested table.

10.0 Reference: EES Conservation and Demand Potential Review, p. 1

"The conservation measures are based on sources such as the Ontario Power Authority, BC Hydro's 2007 Conservation Potential Review, and the Northwest Power and Conservation Council."

10.1 Please provide the ratio of plan targets by sector to achievable potential by sector for the residential, commercial, and industrial sectors of BC Hydro for the years 2012 and 2013?

<u>Response:</u>

BC Hydro has not filed its DSM plans for F2012 or F2013, thus a response to this inquiry cannot be compiled.

Please file a copy of BC Hydro's "Industrial Energy Manager Brochure" at: http://www.bchydro.com/etc/medialib/internet/documents/psbusiness/pdf/a10_595_industrial_energy_manager.Par.0001.File.A10-595-IFS-Plan-Industrial-Energy-Manager.pdf)

10.2 Is FortisBC aware that BC Hydro does not apply these costs against specific energy savings programs? If not, please confirm with BC Hydro?

<u>Response:</u>

Not confirmed. According to BC Hydro, the BCH Power Smart Partner – Transmission (PSP-T) program is a package of several components (including incentive offers, energy manager programs, energy studies, training and awareness programs), and all costs and savings are attributed to the overall program irrespective of whether they were driven from a single component or multiple components. Therefore, the costs for energy managers are applied against the specific PSP-T energy savings program.

A copy of BC Hydro's "Industrial Energy Manager Brochure" is provided as Celgar IR1 Appendix 10.2.

10.3 Please explain FBC's current understanding of BC Hydro's Industrial Energy Manager position?

Response:

FortisBC has only a limited knowledge of the BC Hydro Industrial Energy Manager position.

10.4 Why does FortisBC not offer this type of funding for its industrial customers?

Response:

FortisBC seeks out new opportunities to acquire cost-effective DSM savings, but is concerned about the persistence of any savings derived from an energy manager position.

10.5 Would FortisBC implement a comparable program for its industrial customers? If not, why not?

Response:

Please refer to the response to Celgar IR1 Q10.4.

10.6 Please provide the following information on BC Hydro's Integrated Power offer for Pulp and Paper Customers:

10.6.1 Please file the overview of BC Hydro's Integrated Power Offer for Pulp and Paper customers. (the information is available at http://www.bchydro.com/powersmart/industrial/offers/upgrade/rates/tsr/ipo.html)

Response:

The requested information is provided as Celgar IR1 Appendix 10.6.1.

10.7 Why has FortisBC not provided such a program for its Pulp and Paper customers to leverage Federal Green Transformation Program projects? Please provide a detailed explanation?

Response:

FortisBC has worked with its only pulp and paper customer (Celgar) to identify DSM projects that would qualify under the federal GTP program. Until the current regulatory proceedings involving Celgar and FortisBC are resolved, it is unclear whether, or the extent to which, DSM incentives can be paid by FortisBC to Celgar.

10.8 What work steps did FortisBC undertake to examine this type of offering for its customers?

Response:

Please refer to the response to Celgar IR1 Q6.23.

10.9 Did the BC Government (MEMPR) discuss this type of programming (in 10.8) with FBC?

Response:

No.

10.10 Please describe the work that FortisBC has undertaken with the provincial government in developing a DSM program that addresses the specific challenges faced by the industrial sector including Celgar in the FortisBC service area.

Response:

FortisBC is currently in discussion with The Ministry of Energy and Mines (MEM) and other public utilities regarding implementation of the ISO 50001 Energy Management Systems Standard. ISO 50001 is a structured management framework that integrates energy efficiency into management practices by making better use of existing energy-consuming processes.

10.11 Please describe the level of coordination and cooperation between BC Hydro and FortisBC in establishing competitive DSM programs.

Response:

FortisBC has a productive collaborative relationship with BC Hydro with respect to developing DSM programs.

10.13 Please describe the level of involvement the MEMPR has in developing DSM programs with FortisBC? Can Fortis inquire with MEMPR if their involvement in developing and setting DSM programs is the same at level that exists for BC Hydro and explain if the involvement is more or less and explain what are the differences.

Response:

The Ministry of Energy and Mines (MEM) determines a broad provincial DSM policy framework, including the creation of DSM legislation that public utilities and the BCUC must follow. MEM has delegated the task of developing and implementing DSM programs to the public utilities under the scrutiny of the BCUC.

MEM and FortisBC maintain regular contact to keep up to date on program and policy developments. In cases where there is a collaborative program, such as LiveSmart BC, FortisBC works closely with MEM to determine program design.

The DSM Regulation allows for attribution of savings from codes and standards towards relevant utility market transformation programs, but to date FortisBC has not worked with MEM to utilize this provision.

FortisBC cannot comment on the relative involvement of MEM with BC Hydro.

11.0 Reference: BC Hydro Transmission Project Incentive Calculator

Transmission Project Incentive Calculator

Top of Form

Energy Cost: Blended Rate

Total Incremental* Project Cost (Not incl. HST): 13000000

#	Savings in MWh/yr	Energy Conservation Measure	Description	EML
1	42000	Process	Process Equipment Improvement	25
2		------------------------------	------------------------------	

Sum: 42,000 MWh/yr

Add Row

Estimated Incentive (rounded estimate): $7,500,000

	Simple Payback (in years)	ROI	% of Project Cost
Pre-Incentive	8.55	12%	N/A
Post-Incentive	3.81	26%	58%

* Incremental cost is the incremental cost relative to the baseline. Just as the baseline defines incremental energy savings, it should also define incremental cost. Therefore:
If the baseline of an EE project is existing equipment, then the incremental cost should therefore be full cost.
If the baseline of an EE project is new equipment (because existing equipment reached end of life and the customer needs to replace equipment anyways), then the incremental cost should be the incremental cost of the premium equipment relative to baseline new equipment cost

Bottom of Form

See Also

Project Incentives: Transmission

Conservation Rates: Transmission

11.1 Assuming an industrial customer on Rate Schedule 31 had the following:

A capital project with a cost of $13,000,000

42,000 MWh of annual energy savings associated with the project

11.1.1 What on average would the simple payback be for this customer in the FortisBC service area without a Power Sense Incentive?

Response:

Assuming $0.04476/kWh and $6.25/kVA-month, and 95% load and power factors, the simple payback with no DSM incentive for this theoretical project would be 5.7 years.

11.1.2 What would the estimated incentive be from FortisBC?

Response:

The incentive would be based on a business case assessment by FortisBC, including measure life and a determination of what portion of project costs are directly linked to the energy savings aspects of the project, and hence a custom incentive would be determined. The nominal incentive for this theoretical project based on 10 cents/kWh for demonstrable energy savings, but subject to the forgoing business case assessment and subject to the caveats described in the response to Celgar IR1 Q 6.14 , is $4.20 million.

11.1.3 What would the estimated simple payback be for this customer in the FortisBC service area with a Power Sense Incentive?

Response:

The estimated simple payback for this theoretical project, based on the nominal DSM incentive of $4.2M (and subject to the caveats in the response to Celgar IR1 Q11.1.2), is 3.9 years.

11.1.4 What is the difference between the estimated BC Hydro incentive versus the FortisBC incentive? Please explain.

Response:

The BC Hydro on-line project calculator shows an estimated incentive of $7.5 million, compared to the FortisBC estimated nominal incentive of $4.2 million (a difference of $3.3 million), subject in both cases to the fact that the actual DSM incentive offered would be based on a business case analysis and considerable due diligence (including those considerations listed in the responses to Celgar IR1 Q6.14, Celgar IR1 Q11.1.2 and Celgar IR1 Q6.20).

Given that these estimates are dependent on a number of situational factors, FortisBC believes no significant conclusion can be drawn from this simple example.

11.2 Please confirm the following is an example of the calculation of a BC Hydro financial incentive to a customer:

SAMPLE PROJECT

Let's say that you are planning a system upgrade that will cost $850,000 and save 3,000 MWh per year for 10 years.

Before Incentive

Without any project incentives, this project would pay for itself in less than nine years.

Project costs	$850,000
Projected annual savings	$98,130*
Payback period	8.7 years

Incentive Calculation

The available incentive is calculated based on the projected electricity savings of the upgrade over its entire 10 years lifespan.

$30.9/MWh** × 3,000 MWh/yr × 10 years = $927,000 maximum incentive
(incentive rate) × (annual savings) × (lifespan)

This is capped at 100 per cent of the project costs—in this case, $850,000.

After Incentive

With a project incentive of $850,000, the up-front capital costs and payback period will be completely eliminated. Of course, this project will also continue to save on energy costs for 10 years.

Final project costs	$0
Payback period	0 years
Lifespan electricity savings	$981,300*
Total project savings	$1,831,300

Response:

The calculation appears to be correct, but FortisBC is not certain how it can confirm that this sample calculation is from BC Hydro.

11.3 Please confirm that from the BC Hydro example calculation, the maximum incentive available to a BC Hydro industrial customer would be:

$30.9/MW.h X 9,280 MW.h/yr X 10 years = $2,867,520 maximum incentive

Response:

Not confirmed. The number of MW.h per year differs from the example calculation. Any calculation of an incentive maximum would have to take into consider the factors cited in Celgar IR Q6.20.

11.3.1 Please confirm that the maximum BC Hydro incentive is more than three times greater than the corresponding FortisBC incentive?

Response:

Not confirmed. The maximum BC Hydro incentive would be subject to the factors identified in the response to Celgar IR1 Q6.20.

11.4 Please attach BC Hydro's "New Plant Design Brochure" (it can be found at: http://www.bchydro.com/etc/medialib/internet/documents/psbusiness/pdf/a10_596_new_plant_design.Par.0001.File.A10-596-IFS-Plan-New-Plant-Design.pdf)

Response:

The requested brochure is provided as Celgar IR1 Appendix 11.4.

11.4.1 Is FortisBC aware that BC Hydro does not apply these costs against specific energy savings programs.

Response:

Not confirmed. As per the response to Celgar IR1 Q10.2, this is one of a bundle of measures contained within the BCH PowerSmart Partner program. Although costs (and benefits) are not attributed to specific measures, they are bundled at the program level.

11.5 Please explain FBC's current understanding of BC Hydro's Industrial Energy Manager position.

Response:

Please see the response to Celgar IR1 Q10.3.

11.6 When FortisBC evaluates a DSM project for an industrial customer, what is the maximum level of persistence that FortisBC applies to a project? For example on a BC Hydro DSM project that saves 5,000 MWh per year, BC Hydro can apply 10 years persistence and will count the 5000 MWh saving in each of the 10 years.

Response:

For its 2012-13 DSM Plan the Company used a 10 year effective measure life to calculate the benefits in the TRC test. For each large-scale industrial DSM project, a specific effective measure life would be determined.

11.7 How many years persistence does FortisBC recognize its customer for when providing a DSM incentive.

Response:

The Effective Measure Life (EML) varies greatly between measures from as low as 3 years for certain measures to as long as 30 years for others.

11.8 Does FortisBC calculate savings from a net present value basis?

Response:

Yes.

11.9 Why does FortisBC provide a limit of a 2 year simple payback on DSM projects for Capital costs. Why not have a four year payback limit or no limit at all. Please explain in detail.

Response:

Please see the response to Celgar IR1 Q6.18.

11.10 Please explain whether FortisBC's Industrial DSM offerings are "Competitive" offerings when compared with BC Hydro's Industrial DSM offerings?

Response:

The term "competitive" can be subject to many interpretations. Please see the responses to Celgar IR1 Q10.1 through Q10.13 for comparisons to a number of BC Hydro industrial programs.

11.11 Please explain whether the appropriate incentives are in place for an investor owned utility such as FortisBC to pursue competitive, cost-effective DSM programs in cooperation with BC Hydro?

Response:

FortisBC believes that an appropriate regulatory framework is in place that allows FortisBC to pursue cost-effective DSM programs, including a number programs developed and/or operated cooperatively with other entities including BC Hydro.

11.12 Please file the 2007 BC Energy Plan.

Response:

The 2007 BC Energy Plan is provided as Celgar IR1 Appendix 11.12.

PDF Version
[Printer-friendly - ideal for printing entire document]

DEMAND-SIDE MEASURES REGULATION 326/2008

Published by Quickscribe Services Ltd.
Updated To:
[includes B.C. Reg. 326/2008 (effective June 1, 2009)]

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DEMAND-SIDE MEASURES REGULATION 326/2008

B.C. Reg. 326/2008

[includes B.C. Reg. 326/2008 (effective June 1, 2009)]

Contents

[Provisions of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473, relevant to the enactment of this regulation: section 125.1 (4) (e)]

Definitions

1. In this regulation:

"Act" means the *Utilities Commission Act*;

"bulk electricity purchaser" means a public utility that purchases electricity from the authority for resale to the public utility's customers;

"community engagement program" means a program delivered by

(a) a public utility to a public entity either

(i) to increase the public entity's awareness about ways to increase energy conservation and energy efficiency or to encourage the public entity to conserve energy or use energy efficiently, or

(ii) to assist the public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently, or

(b) a public utility in cooperation with a public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently;

"education program" means an education program about energy conservation and efficiency, and includes the funding of the development of such a program;

"energy device" has the same meaning as in the *Energy Efficiency Act*;

"energy efficiency training" means training for persons who

(a) manufacture, sell or install energy-efficient products,

(b) design, construct or act as a real estate broker whith respect to energy-efficient buildings,

(c) manage energy systems in buildings, or

(d) conduct energy efficiency audits;

"energy-using product" has the same meaning as in the *Energy Efficiency Act* (Canada);

"expenditure portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the Act;

"low-income household" means a household whose residents receive service from the public utility and who have, in a taxation year, a before-tax annual household income equal to or less than the low-income cut off established by Statistics Canada for that year for households of that type;

"plan portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in a plan submitted under section 44.1 of the Act;

"public awareness program" means a program delivered by a public utility

(a) to increase the awareness of the public, including the public utility's customers, about ways to increase energy conservation and energy efficiency or to encourage the public, including the public utility's customers, to conserve energy or use energy efficiently, or

(b) to increase participation by the public utility's customers in other demand-side measures proposed by the public utility in an expenditure portfolio or a plan portfolio

but does not include a program to increase the amount of energy sold or delivered by the public utility;

"public entity" means a local government, first nation, non-profit society incorporated under the *Society Act* or trade union;

"regulated item" means

(a) an energy device

(b) an energy-using product

(c) a building design, or

(d) thermal insulation;

"school" means a school regulated under the *School Act* or the *Independent School Act*

"specified demand-side measure" means

(a) a demand-side measure referred to in section 3 (c) or (d),

(b) the funding of energy efficiency training,

(c) a community engagement program, or

(d) a technology innovation program;

"specified standard" means a standard in any of the following:

(a) the Energy Efficiency Standards Regulation, B.C. Reg. 389/93;

(b) the Energy Efficiency Regulations S.O.R./94-651;

(c)

the British Columbia Building Code, if the standard promotes energy conservation or the efficient use of energy;

"technology innovation program" means a program

(a) to develop a technology, a system of technologies, a building design or an industrial facility design that is

(i) not commonly used in British Columbia, and

(ii) the use of which could directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy,

(b) to do what is described in paragraph (a) and to give demonstrations to the public of any results of doing what is described in paragraph (a), or

(c) to gather information about a technology, a system of technologies, a building design or an industrial design referred to in paragraph (a).

Application

(REP) Jun 01/09

2. (1) *Repealed.* [B.C. Reg. 326/2008]

(2) Effective June 1, 2009,

(a) *Spent.*

(b) section 3 does not apply to a public utility that is owned or operated by a local government or has fewer than 10,000 customers.

[am. B.C. Reg. 326/2008.]

Adequacy

3. A public utility's plan portfolio is adequate for the purposes of section 44.1 (8) (c) of the Act only if the plan portfolio includes all of the following:

(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools in the public utility's service area,

(d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.

Cost effectiveness

4. (1) Subject to subsections (4) and (5), the commission, in determining for the purposes of section 44.1 (8) (c) or 44.2 (5) (d) of the Act the cost-effectiveness of a demand-side measure proposed in an expenditure portfolio or a plan portfolio, amy compare the costs and benefits of

(a) a demand-side measure individually,

(b) the demand-side measure and other demand-side measures in the portfolio, or

(c) the portfolio as a whole.

(2)

In determining whether a demand-side measure referred to in section 3 (a) is cost effective, the commission must,

(a) in addition to conducting any other analysis the commission considers appropriate, use the total resource cost test, and

(b) in using the total resource cost test, consider the benefit of the demand-side measure to be 130% of its value when determined without reference to this subsection.

(3) In determining whether a demand-side measure of a bulk electricity purchaser is cost-effective, the commission must consider the benefit of the avoided supply cost to be the authority's long-term marginal cost of acquiring new electricity to replace the electricity sold to the bulk electricity purchaser and not the bulk electricity purchaser's cost of purchasing electricity from the authority.

(4) The commission must determine the cost-effectiveness of a specified demand-side measure proposed in a plan portfolio or an expenditure portfolio by determining whether the portfolio is cost effective as a whole.

(5) If the commission is satisfied that a public awareness program proposed in a plan portfolio or an expenditure portfolio is likely to accomplish the goals set out in paragraph (a) or (b) of the definition of "public awareness program", the commission must determine the cost-effectiveness of the program by determining whether the portfolio is cost-effective as a whole.

(6) The commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure.

(7) In considering the benefit of a demand-side measure that, in the commission's opinion, will increase the market share of a regulated item with respect to which there is a specified standard that has not yet commenced, the commission may include in the benefit a proportion of the benefit that, in the commission's opinion, will result from the commencement and application of the specified standard with respect to the regulated item.

[Provisions of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473, relevant to the enactment of this regulation: section 125.1 (4) (e)]

INITIATIVES FOR INDUSTRIAL CUSTOMERS

ENERGY EFFICIENCY FEASIBILITY STUDY

With this generously funded study, you can move forward with confidence on your best energy efficiency solutions.

You may already know which of your industrial systems is using more energy than it actually needs. You may even have a good idea of which equipment is causing the problem, and which solutions are available to you. But all of that doesn't mean you have the detailed information you need to move forward with confidence.

Our Energy Efficiency Feasibility Study provides an in-depth analysis of energy solutions within a single system. It's all about getting the cost and benefit details you need to make strategic decisions for increasing efficiency—and profitability—at your facility.

We'll provide up to 100 per cent funding for an energy efficiency expert to visit your site and analyze your options. In the end, you will be able to build a solid business case for your best upgrade opportunities, and then readily apply for major upgrade funding under Power Smart's Project Incentives.

The result? You'll save big on upgrade costs. You'll save big on operating costs. And you'll enjoy all of the other benefits of a high-efficiency, high-performance system, like improved reliability, better quality products, and higher customer satisfaction.

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Get everything you need to build a business case and upgrade your facility with total confidence.

STREAMLINED FUNDING

Use your study report to apply directly for major incentives to upgrade your system.

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First, you'll save with major study funding. Then, you'll save for years with the energy-saving upgrades that follow.

IS THIS INITIATIVE FOR YOU?

This assessment is open to all of BC Hydro's industrial customers who use more than $50,000 of electricity annually.

- The target system should consume at least one gigawatt hour per year. (For a 200 horsepower system, that's roughly 6,000 hours of operation.)
- Non-motorized systems such as lighting and process control may also be eligible.

BC hydro powersmart

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This study is for organizations that are ready to take an in-depth look at specific efficiency solutions, with an eye toward carrying out efficiency upgrades. An energy efficiency expert will come to your site to conduct a detailed analysis of your system.

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  We'll fund 75 per cent of the cost of the study right away. If you follow through with an efficiency upgrade within 18 months, we will also cover the remaining 25 per cent.
- **Detailed report**
  Your study report will equip you with everything you need to build a solid business case for efficiency upgrades, including estimated savings and implementation costs.
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DISCOVER TO UPGRADE, IN FOUR SIMPLE STEPS

When tackled in order, our discovery initiatives let you zero in on your strongest upgrade opportunities. Note that it's completely up to you where you start the process, depending on your facility or system. We can help you choose your best options.

STEP ONE:
FIND OUT WHERE TO BEGIN

- Customer Site Investigation
- Plant-Wide Audit

STEP TWO:
LOOK AT A SINGLE SYSTEM

- End-Use Assessment

STEP THREE:
STUDY YOUR SOLUTIONS IN DETAIL

- Energy Efficiency Feasibility Study

STEP FOUR:
TAKE ACTION ON AN UPGRADE

- Project Incentives
- Conservation Rates

GET STARTED

Contact your Key Account Manager or talk to BC Hydro Customer Care.

604 453 6400 Lower Mainland
1 866 453 6400 elsewhere in BC
bchydro.com/industrial
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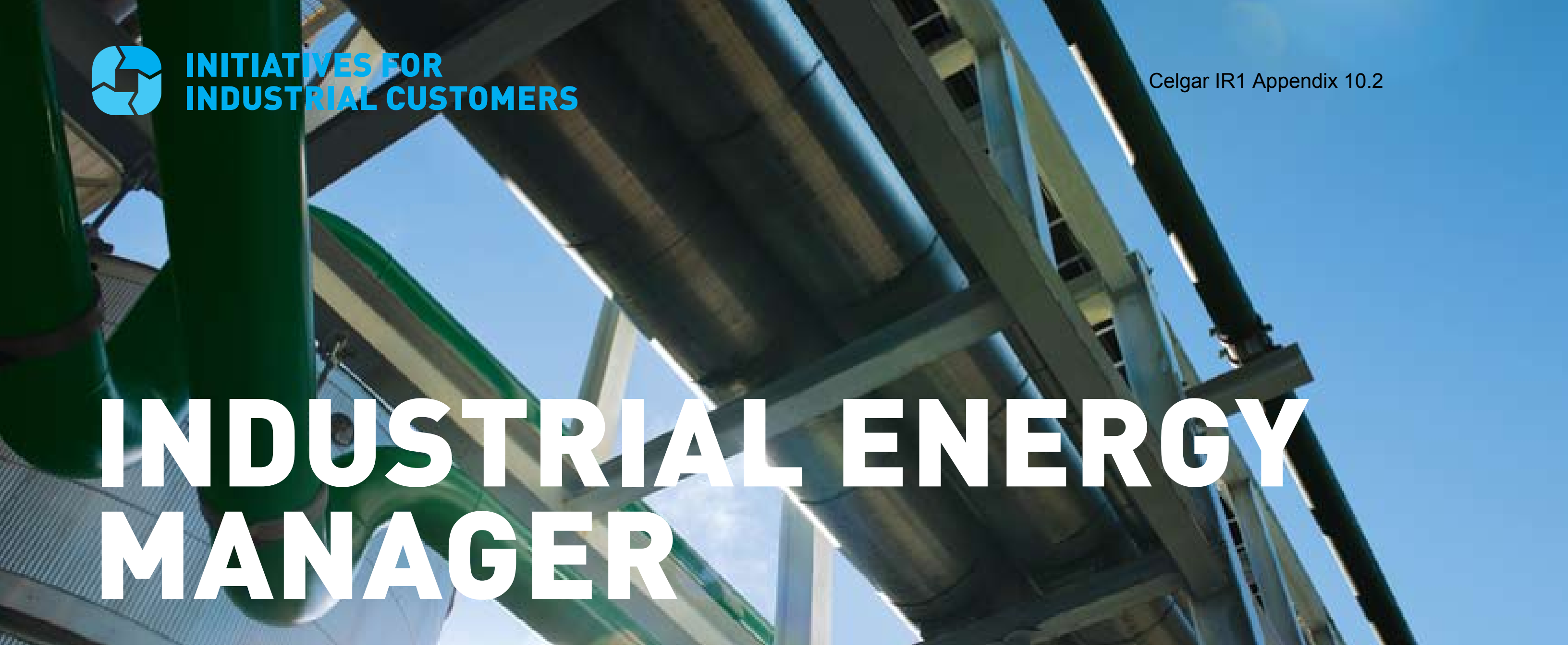
INITIATIVES FOR
INDUSTRIAL CUSTOMERS



INDUSTRIAL ENERGY MANAGER

Get major funding for your own on-site expert in smart energy management.

There are plenty of ways to save money on energy costs. And yet these great opportunities often go unexplored due to a simple lack of human resources.

This is where an industrial energy manager funded by Power Smart can create a competitive advantage, working on your site every day to cut costs while boosting productivity and product quality. We offer two great funding options for customers looking for that advantage.

Under our Industrial Energy Manager initiative, the basic option provides major funding for you to hire your own dedicated on-site energy manager. If you choose the flagship Sustainable Energy Management Planning (SEMP) option, your funding increases and you gain additional funding for your energy manager to spearhead your long-term energy planning. You'll also get access to further incentives to support your efforts across your whole organization.

The ultimate goal? To build smart energy management into your everyday business practices, so that you save on energy, save on operating costs, and grow a competitive advantage for years to come.

MAJOR FUNDING

With generous funding, you'll get the power of great energy management at minimal cost.

SAVE FOR YEARS

Your on-site energy manager will work to reduce energy waste year after year.

COMPETITIVE EDGE

Smart energy management gives you a wide-reaching advantage—from your productivity, to your profitability, to your reputation for efficiency.

IS THIS INITIATIVE FOR YOU?

You're welcome to take part if your site uses more than $200,000 of electricity annually. A few additional qualifications apply:

- You are willing to hire your energy manager as a full-time or part-time employee. (If choosing the basic option, you can opt to hire an outside consultant).
- Your candidate's salary and qualifications meet certain criteria, subject to approval.
- If you choose the SEMP option, we ask that you commit to efficiency by becoming a Power Smart Partner and taking part in Employee Energy Awareness, Energy Management Assessment, and Monitoring, Targeting and Reporting.

BC hydro
powersmart

HERE'S WHAT WE OFFER

Both options include funding to hire and train your on-site energy manager. For many customers, isolated efficiency projects are simply not enough; they want comprehensive energy management to grow their savings in the long-term. These customers should choose the SEMP option.

OPTION 1: ENERGY MANAGER WITH SEMP

Our flagship SEMP option initiative provides advanced funding to hire an energy manager to develop and implement your Sustainable Energy Management Plan.

- Salary
  We offer funding for up to two years for your energy manager's salary.
  We cover 100 per cent for three months, then 75 per cent for the remainder.
- Training
  We offer full funding for the required training of your new energy manager.
- SEMP Workshop
  We fully fund a workshop to facilitate your custom plan.
- Energy Management Assessment
  We pay the full cost of an on-site management assessment.
- Coaching
  We offer 60 per cent funding for up to six months for management coaching.
- Monitoring, Targeting and Reporting (MT&R)
  Choosing the SEMP option gives you access to generous funding to create your MT&R program to measure your progress and set goals for the future.
- Employee Energy Awareness
  The SEMP option boosts your funding to 100 per cent for a customized, on-site workshop, plus provides funding for campaign kick-off events.

OPTION 2: ENERGY MANAGER (BASIC)

This basic option is for customers who are looking for an on-site energy manager to build a project-based efficiency program.

- Salary
  We'll cover 60 per cent of your energy manager's salary, for up to two years.
- Training
  We offer full funding for the required training of your new energy manager.
- Energy Management Assessment
  We pay the full cost of an on-site management assessment.
- Coaching
  We offer 60 per cent funding for up to six months for management coaching.
- Monitoring, Targeting and Reporting
  We offer access to generous funding to create an MT&R program to measure your progress and set goals for the future.

GET STARTED

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Integrated Power Offer For Pulp & Paper Customers

BC Hydro posted the following:

January 6, 2011

BC Hydro supports Cariboo Pulp and Paper's clean energy plans

Frequently Asked Questions

BC Hydro is working with its pulp and paper customers to identify win-win opportunities that will result in customers securing funding under the federal government's Green Transformation Program and BC Hydro securing new cost-effective energy efficiency savings and clean electricity generation.

Introduced in June 2009, Natural Resources Canada's Pulp and Paper Green Transformation Program supports innovation and investment in areas such as energy efficiency and renewable energy production technologies. Up to $1 billion has been set aside to assist pulp and paper producers, eight of which are BC Hydro customers.

Recognizing that its many Power Smart incentives and power acquisition processes can be complex and difficult to navigate with many points of contact, BC Hydro is taking an "integrated offer" approach with eligible pulp and paper customers. The Integrated Power Offer (IPO) will capitalize on the synergies presented when energy efficiency savings and electricity generation opportunities are considered together. BC Hydro has assigned a team of experts to work with each customer to develop an inventory of potential energy efficiency, demand response and power generation opportunities. The resultant IPO projects will provide economic and environmental benefits to B.C.'s pulp and paper industry and cost-effective energy solutions for BC Hydro and ratepayers.

BC Hydro has initially extended the IPO to its pulp and paper customers because of that sector's immediate opportunity to capture federal Green Transformation Program funding. Longer term, BC Hydro will be exploring opportunities to introduce an integrated offer to other industrial customers and possibly other customer classes.

For more information on BC Hydro's Integrated Power Offer, please contact your Key Account Manager or the IPO Administrator.

Pulp and Paper Green Transformation Program

On June 17, 2009, Natural Resources Canada (NRCan) announced the "Pulp and Paper Green Transformation Program" aimed at supporting innovation and investment in areas offering demonstrable environmental benefits, such as energy efficiency and renewable energy production.

Up to $1 billion has been set aside for capital projects related to enhanced energy efficiency, renewable energy production, and other environmental benefits.

For further information on the Federal Government's program, which is being administered by Natural Resources Canada, please visit Pulp and Paper Green Transformation Program.

Last Modified: Jan 6, 2011

INITIATIVES FOR INDUSTRIAL CUSTOMERS

NEW PLANT DESIGN

Reap the long-term benefits of efficient plant design—simply and cost-effectively.

It's no secret that energy is a major expense for any industrial facility. That's a big part of the reason why plant owners are looking to build efficiency right into their facilities, from the ground up.

We're here to help you do exactly that. Power Smart New Plant Design provides funding and design expertise so you can move forward with confidence when designing a new or expanded facility.

Start with a fully funded design study to explore your options in-depth. Then use your findings to apply for major financial incentives to take action on your efficient designs—as much as 75 to 100 per cent of your incremental costs, depending on the type of project. Even better, we've organized it all into a streamlined bundle to allow you to take part without any interruption to your design process.

Why design from the ground up for efficiency? For one thing, it's much simpler and more effective than expensive retrofits down the road. More importantly, it's about giving yourself a major competitive head start, all in one clever move.

IS THIS INITIATIVE FOR YOU?

All BC Hydro industrial customers are welcome to take part if they meet two basic requirements:

- You're planning either a new greenfield facility, or you are expanding an existing facility enough to increase the power load by at least five per cent.
- Your facility has a savings potential of more than $9,000 annually (as determined by your fully-funded energy study).

LIFE-LONG SAVINGS

You'll enjoy lower operating costs over the lifespan of the facility.

RELIABILITY AND PERFORMANCE

State-of-the art efficiency means enhanced productivity and product quality.

BOOST YOUR REPUTATION

Get recognized as a leader for your smart facility designs and progressive approach to energy use.

BC hydro powersmart

HERE'S WHAT WE OFFER

This initiative unfolds in three stages, all organized into a streamlined process so that there's no interruption to your design schedule. First, we help you study the efficient design options available to you. Second, we provide you with major incentives to carry out the design recommendations from your study. Third, we celebrate and promote your accomplishment through our recognition program.

From there, you'll have access to our full range of efficiency initiatives to support and grow your savings well into the future.

DISCOVER

ENERGY EFFICIENCY FEASIBILITY STUDY

Make informed and confident choices to meet your facilities energy needs with this comprehensive energy study. We'll determine your plant's energy baseline, and then uncover a range of design options available to improve your efficiency.

- 100 per cent fully funded.
- Gives you access to Power Smart engineering experts who will work with you and provide recommendations on the technical aspects of your design.
- Your study report can be used to apply for Power Smart Project Incentives.

UPGRADE

PROJECT FUNDING

System upgrades pay for themselves with lower energy and maintenance costs. But to make your project even more financially attractive, Power Smart has two great funding options. We can advise you on the best option for your project.

- Project Incentives
  These financial incentives cover as much as 75 to 100 per cent of your incremental construction costs (i.e. above standard, inefficient design options). This incentive will significantly reduce the payback period of your efficient design.
- Conservation Rates
  Our rates provide you with an increased financial incentive to save. This is ideal for customers who are looking to reduce future operating costs.

SUPPORT

PARTNER RECOGNITION

We believe in giving credit where credit is due. Complete your new construction with a more efficient design and sign a Power Smart Partner pledge, and we'll be proud to recognize your commitment.

- Top partners get profiled in print campaigns and on our website, and are eligible for milestone rewards and recognition at the annual Power Smart Excellence Awards.
- You'll be welcome to leverage the Power Smart brand in your marketing.
- Participation is free.

WE'LL MAKE IT SIMPLE

Good design is really just the beginning. By taking part, you'll gain access to the whole range of Power Smart funding offers and expert resources—everything from employee energy awareness training, to funding to hire a long-term energy manager, to invitations to participate in demonstrations of energy technology applications new to BC.

GET STARTED

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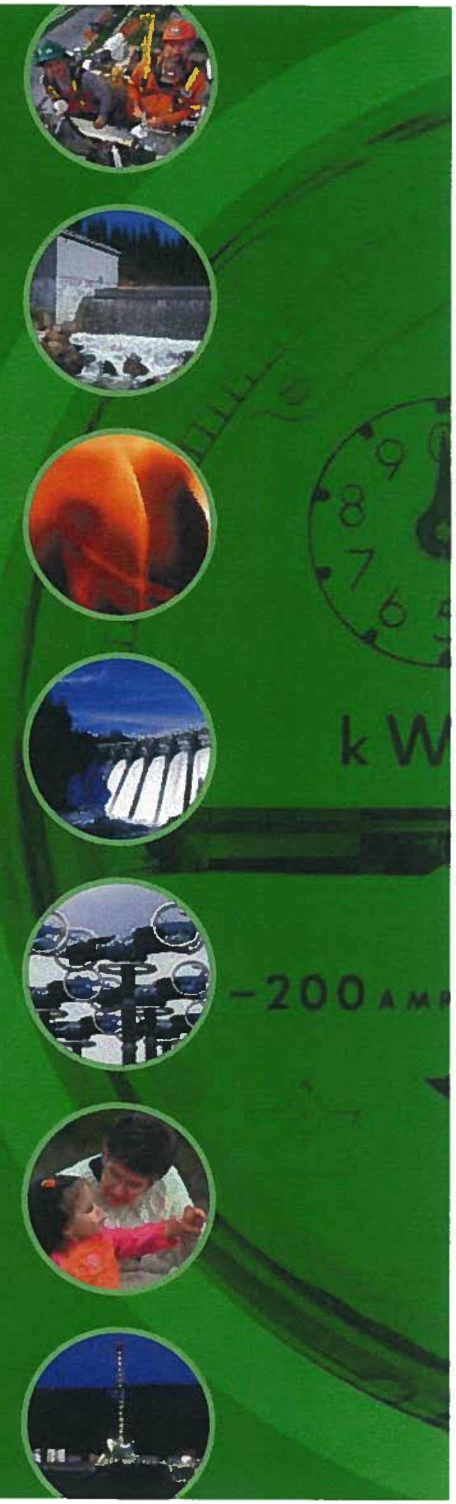
The BC Energy Plan

A Vision for Clean Energy Leadership



BRITISH COLUMBIA
The Best Place on Earth

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MESSAGE FROM THE PREMIER

The BC Energy Plan: A Vision for Clean Energy Leadership is British Columbia's plan to make our province energy self-sufficient while taking responsibility for our natural environment and climate. The world has turned its attention to the critical issue of global warming. This plan sets ambitious targets. We will pursue them relentlessly as we build a brighter future for B.C.

The BC Energy Plan sets out a strategy for reducing our greenhouse gas emissions and commits to unprecedented investments in alternative technology based on the work that was undertaken by the Alternative Energy Task Force. Most importantly, this plan outlines the steps that all of us – including industry, environmental agencies, communities and citizens – must take to reach these goals for conservation, energy efficiency and clean energy so we can arrest the growth of greenhouse gases and reduce human impacts on the climate.

As stewards of this province, we have a responsibility to manage our natural resources in a way that ensures they both meet our needs today and the needs of our children and grandchildren. We will all have to think and act differently as we develop innovative and sustainable solutions to secure a clean and reliable energy supply for all British Columbians.

Our plan will make B.C. energy self-sufficient by 2016. To do this, we must maximize our conservation efforts. Conservation will reduce pressure on our energy supply and result in real savings for those who use less energy. Individual actions that reduce our own everyday energy consumption will make the difference between success and failure. For industry, conservation can lead to an effective, productive and significant competitive advantage. For communities, it can lead to healthier neighbourhoods and lifestyles for all of us.

We are looking at how we can use clean alternative energy sources, including bioenergy, geothermal, fuel cells, water-powered electricity, solar and wind to meet our province's energy needs. With each of these new options comes the opportunity for new job creation in areas such as research, development, and production of innovative energy and conservation solutions. The combination of renewable alternative energy sources and conservation will allow us to pursue our potential to become a net exporter of clean, renewable energy to our Pacific neighbours.

Just as the government's energy vision of 40 years ago led to massive benefits for our province, so will our decisions today. **The BC Energy Plan** will ensure a secure, reliable, and affordable energy supply for all British Columbians for years to come.

Premier Gordon Campbell

MESSAGE FROM THE MINISTER

The BC Energy Plan: A Vision for Clean Energy Leadership is a made-in-B.C. solution to the common global challenge of ensuring a secure, reliable supply of affordable energy in an environmentally responsible way. In the next decade government will balance the opportunities and increased prosperity available from our natural resources while leading the world in sustainable environmental management.

This energy plan puts us in a leadership role that will see the province move to eliminating or offsetting greenhouse gas emissions for all new projects in the growing electricity sector, end flaring from oil and gas producing wells, and put in place a plan to make B.C. electricity self-sufficient by 2016.

In developing this plan, the government met with key stakeholders, environmental non-government organizations, First Nations, industry representatives and others. In all, more than 100 meetings were held with a wide range of parties to gather ideas and feedback on new policy actions and strategies now contained in **The BC Energy Plan**.

By building on the strong successes of Energy Plan 2002, this energy plan will provide secure, affordable energy for British Columbia. Today, we reaffirm our commitment to public ownership of our BC Hydro assets while broadening our supply of available energy.

We look towards British Columbia's leading edge industries to help develop new, greener generation technologies with the support of the new **Innovative Clean Energy Fund**. We're planning for tomorrow, today. Our energy industry creates jobs for British Columbians, supports important services for our families, and will play an important role in the decade of economic growth and environmental sustainability that lies ahead.

The Ministry of Energy, Mines and Petroleum Resources is responding to challenges and opportunities by delivering innovative, sustainable ways to develop British Columbia's energy resources.

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

THE BC ENERGY PLAN HIGHLIGHTS

British Columbia's current electricity supply resources are 90 per cent clean and new electricity generation plants will have zero net greenhouse gas emissions.

In 2002, the Government of British Columbia launched an ambitious plan to invigorate the province's energy sector. Energy for Our Future: A Plan for BC was built around four cornerstones: low electricity rates and public ownership of BC Hydro; secure, reliable supply; more private sector opportunities; and environmental responsibility with no nuclear power sources. Today, our challenges include a growing energy demand, higher prices, climate change and the need for environmental sustainability. **The BC Energy Plan: A Vision for Clean Energy Leadership** builds on the successes of the government's 2002 plan and moves forward with new policies to meet the challenges and opportunities ahead.

Environmental Leadership

The BC Energy Plan puts British Columbia at the forefront of environmental and economic leadership by focusing on our key natural strengths and our competitive advantages of clean and renewable sources of energy. The plan further strengthens our environmental leadership through the following key policy actions:

- **Zero greenhouse gas emissions from coal fired electricity generation.**
- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**
- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **No nuclear power.**
- **Best coalbed gas practices in North America.**
- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**

A Strong Commitment to Energy Conservation and Efficiency

Conservation is integral to meeting British Columbia's future energy needs. **The BC Energy Plan** sets ambitious conservation targets to reduce the growth in electricity used within the province. British Columbia will:

- **Set an ambitious target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Implement energy efficient building standards by 2010.**

Current per household electricity consumption for BC Hydro customers is about 10,000 Kwh per year. Achieving this conservation target will see electricity use per household decline to approximately 9,000 Kwh per year by 2020.

Energy Security

The Government of British Columbia is taking action to ensure that the energy needs of British Columbians continue to be met now and into the future. As part of ensuring our energy security, **The BC Energy Plan** sets the following key policy actions:

- **Maintain public ownership of BC Hydro and the BC Transmission Corporation.**
- **Maintain our competitive electricity rate advantage.**
- **Achieve electricity self-sufficiency by 2016.**
- **Make small power part of the solution through a set purchase price for electricity generated from projects up to 10 megawatts.**
- **Explore value-added opportunities in the oil and gas industry by examining the viability of a new petroleum refinery and petrochemical industry.**
- **Be among the most competitive oil and gas jurisdictions in North America.**
- **BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known.**

Investing in Innovation

British Columbia has a proven track record in bringing ideas and innovation to the energy sector. From our leadership and experience in harnessing our hydro resources to produce electricity, to our groundbreaking work in hydrogen and fuel cell technology, British Columbia has always met its future energy challenges by developing new, improved and sustainable solutions. To support future innovation and to help bridge the gap experienced in bringing innovations through the pre-commercial stage to market, government will:

- **Establish an Innovative Clean Energy Fund of $25 million.**
- **Implement the BC Bioenergy Strategy to take full advantage of B.C.'s abundant sources of renewable energy.**
- **Generate electricity from mountain pine beetle wood by turning wood waste into energy.**

Ambitious Energy Conservation and Efficiency Targets

The more energy that is conserved, the fewer new sources of supply we will require in the future. That is why British Columbia is setting new conservation targets to reduce growth in electricity demand.

Inefficient use of energy leads to higher costs and many environmental and security of supply problems.

Conservation Target

The BC Energy Plan sets an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020. This will require building on the "culture of conservation" that British Columbians have embraced in recent years.

The plan confirms action on the part of government to complement these conservation targets by working closely with BC Hydro and other utilities to research, develop, and implement best practices in conservation and energy efficiency and to increase public awareness. In addition, the plan supports utilities in British Columbia and the BC Utilities Commission pursuing all cost effective and competitive demand side management programs. Utilities are also encouraged to explore and develop rate designs to encourage efficiency, conservation and the development of renewable energy.

Future energy efficiency and conservation initiatives will include:

- Continuing to remove barriers that prevent customers from reducing their consumption.
- Building upon efforts to educate customers about the choices they can make today with respect to the amount of electricity they consume.
- Exploring new rate structures to identify opportunities to use rates as a mechanism to motivate customers either to use less electricity or use less at specific times.
- Employing new rate structures to help customers implement new energy efficient products and technologies and provide them with useful information about their electricity consumption to allow them to make informed choices.
- Advancing ongoing efforts to develop energy-efficient products and practices through regulations, codes and standards.

The average household uses about 10,000 kilowatt-hours of electricity per year.

POLICY ACTIONS

COMMITMENT TO CONSERVATION

- **Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.**
- **Encourage utilities to pursue cost effective and competitive demand side management opportunities.**
- **Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.**

Implement Energy Efficiency Standards for Buildings by 2010

British Columbia implemented *Energy Efficient Buildings: A Plan for BC* in 2005 to address specific barriers to energy efficiency in our building stock through a number of voluntary policy and market measures. This plan has seen a variety of successes including smart metering pilot projects, energy performance measurement and labelling, and increased use of Energy Star appliances. In 2005, B.C. received a two year, $11 million federal contribution from the Climate Change Opportunities Envelope to support implementation of this plan.

Working together industry, local governments, other stakeholders and the provincial government will determine and implement cost effective energy efficiency standards for new buildings by 2010. Regulated standards for buildings are a central component of energy efficiency programs in leading jurisdictions throughout the world.

The BC Energy Plan supports reducing consumption by raising awareness and enhancing the efforts of utilities, local governments and building industry partners in British Columbia toward conservation and energy efficiency.

Aggressive Public Sector Building Plan

The design and retrofit of buildings and their surrounding landscapes offer us an important means to achieve our goal of making the government of British Columbia carbon neutral by 2010, and promoting Pacific Green universities, colleges, hospitals, schools, prisons, ferries, ports and airports.

British Columbia communities are already recognized leaders in innovative design practices. We know how to build smarter, faster and smaller. We know how to increase densities, reduce building costs and create new positive benefits for our environment. We know how to improve air quality, reduce energy consumption and make wise use of other resources, and how to make our landscapes and buildings healthy places for living, working and learning. We know how to make it affordable.

Government will set the following ambitious goals for all publicly funded buildings and landscapes and ask the Climate Action Team to determine the most credible, aggressive and economically viable options for achieving them:

- Require integrated environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
- Supply green, healthy workspaces for all public service employees.
- Capture the productivity benefits for people who live and work in publicly funded buildings such as reduced illnesses, less absenteeism, and a better learning environment.
- Aim not only for the lowest impact, but also for restoration of the ecological features of the surrounding landscapes.

Gigawatt = 1,000,000 kilowatts
Kilowatt = amount of power to light ten 100-watt incandescent light bulbs.

ENERGY CONSERVATION AND EFFICIENCY

Community Action on Energy Efficiency

British Columbia is working in partnership with local governments to encourage energy conservation at the community level through the Community Action on Energy Efficiency Program. The program promotes energy efficiency and community energy planning projects, providing direct policy and technical support to local governments through a partnership with the Fraser Basin Council. A total of 29 communities are participating in the program and this plan calls for an increase in the level of participation and expansion of the program to include transportation actions. The Community Action on Energy Efficiency Program is a collaboration among the provincial ministries of Energy, Mines and Petroleum Resources, Environment, and Community Services, Natural Resources Canada, the Fraser Basin Council, Community Energy Association, BC Hydro, FortisBC, Terasen Gas, and the Union of BC Municipalities.

Leading the Way to a Future with Green Buildings and Green Cities

British Columbia has taken a leadership role in the development of green buildings. Through the Green Buildings BC Program, the province is working to reduce the environmental impact of government buildings by increasing energy and water efficiency and reducing greenhouse gas emissions. Through this program, and the Energy Efficient Buildings Strategy that establishes energy efficiency targets for all types of buildings, the province is inviting businesses, local governments and all British Columbians to do their part to increase energy efficiency and reduce greenhouse gas emissions.

The Green Cities Project sets a number of strategies to make our communities greener, healthier and more vibrant places to live. British Columbia communities are already recognized leaders in innovative sustainability practices, and the Green Cities Project will provide them with additional resources to improve air quality, reduce energy consumption and encourage British Columbians to get out and enjoy the outdoors. With the Green Cities Project, the provincial government will:

- Provide $10 million a year over four years for the new LocalMotion Fund, which will cost share capital projects on a 50/50 basis with municipal governments to build bike paths, walkways, greenways and improve accessibility for people with disabilities.
- Establish a new Green City Awards program to encourage the development and exchange of best practices by communities, with the awards presented annually at the Union of British Columbia Municipalities convention.
- Set new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.
- Commit to making new investments in expanded rapid transit, support for fuel cell vehicles and other innovations.

Industrial Energy Efficiency Program

Government will establish an Industrial Energy Efficiency Program for British Columbia to address challenges and issues faced by the B.C. industrial sector and support the Canada wide industrial energy efficiency initiatives. The program will encourage industry driven investments in energy efficient technologies and processes; reduce emissions and greenhouse gases; promote self generation of power; and reduce funding barriers that discourage energy efficiency in the industrial sector. Some specific strategies include developing a results based pilot program with industry to improve energy efficiency and reduce overall power consumption and promote the generation of renewable energy within the industrial sector.

The 2010 Olympic and Paralympics Games: Sustainability in Action

In 2010 Vancouver and Whistler will host the Winter Olympic and Paralympic Games. The 2010 Olympic Games are the first that have been organized based on the principles of sustainability.

All new buildings for the Olympics will be designed and built to conserve both water and materials, minimize waste, maximize air quality, protect surrounding areas and continue to provide environmental and community benefits over their lifetimes. Existing venues will be upgraded to showcase energy conservation and efficiency and demonstrate the use of alternative heating/cooling technologies. Wherever possible, renewable energy sources such as wind, solar, micro hydro, and geothermal energy will be used to power and heat all Games facilities.

Transportation for the 2010 Games will be based on public transit. This system – which will tie event tickets to transit use – will help reduce traffic congestion, minimize local air pollution and limit greenhouse gas emissions.

POLICY ACTIONS

BUILDING STANDARDS, COMMUNITY ACTION AND INDUSTRIAL EFFICIENCY

- **Implement Energy Efficiency Standards for Buildings by 2010.**
- **Undertake a pilot project for energy performance labelling of homes and buildings in coordination with local and federal governments, First Nations and industry associations.**
- **New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.**
- **Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.**
- **Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.**

British Columbia benefits from the public ownership of BC Hydro and the BC Transmission Corporation.

POLICY ACTIONS

SELF-SUFFICIENCY BY 2016

- **Ensure self-sufficiency to meet electricity needs, including "insurance."**
- **Establish a standing offer for clean electricity projects up to 10 megawatts.**
- **The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.**
- **Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.**
- **Ensure that the province remains consistent with North American transmission reliability standards.**

Electricity Security

Electricity, while often taken for granted, is the lifeblood of our modern economy and key to our entire way of life. Fortunately, British Columbia has been blessed with an abundant supply of clean, affordable and renewable electricity. But today, as British Columbia's population has grown, so too has our demand for electricity. We are now dependent on other jurisdictions for up to 10 per cent of our electricity supply. BC Hydro estimates demand for electricity to grow by up to 45 per cent over the next 20 years.

We must address this ever increasing demand to maintain our secure supply of electricity and the competitive advantage in electricity rates that all British Columbians have enjoyed for the last 20 years. There are no simple solutions or answers. We have an obligation to future generations to chart a course that will ensure a secure, environmentally and socially responsible electricity supply.

To close this electricity gap, and for our province to become electricity self-sufficient, will require an innovative electricity industry and the real commitment of all British Columbians to conservation and energy efficiency.

The New Relationship and Electricity

The Government of British Columbia is working with First Nations to restore, revitalize and strengthen First Nations communities. The goal is to build strong and healthy relationships with First Nations people guided by the principles of trust and collaboration. First Nations share many of the concerns of other British Columbians in how the development of energy resources may impact as well as benefit their communities. In addition, First Nations have concerns with regard to the recognition and respect of Aboriginal rights and title.

By focusing on building partnerships between First Nations, industry and government, tangible social and economic benefits will flow to First Nations communities across the province and assist in eliminating the gap between First Nations people and other British Columbians.

Government is working every day to ensure that energy resource management includes First Nations' interests, knowledge and values. By continuing to engage First Nations in energy related issues, we have the opportunity to share information and look for opportunities to facilitate First Nations' employment and participation in the electricity sectors to ensure that First Nations people benefit from the continued growth and development of British Columbia's resources. **The BC Energy Plan** provides British Columbia with a blueprint for facing the many energy challenges and opportunities that lay ahead. It provides an opportunity to build on First Nations success stories such as:

- First Nations involvement in independent power projects, such as the Squamish First Nation's participation in the Furry Creek and Ashlu hydro projects.

- Almost $4 million will flow to approximately 10 First Nations communities across British Columbia to support the implementation of Community Energy Action Plans as part of the First Nation and Remote Community Clean Energy Program.
- The China Creek independent power project was developed by the Hupacasath First Nation on Vancouver Island.

Achieve Electricity Self-Sufficiency by 2016

Achieving electricity self-sufficiency is fundamental to our future energy security and will allow our province to achieve a reliable, clean and affordable supply of electricity. It also represents a lasting legacy for future generations of British Columbians. That's why government has committed that British Columbia will be electricity self-sufficient within the decade ahead.

Through **The BC Energy Plan**, government will set policies to guide BC Hydro in producing and acquiring enough electricity in advance of future need. However, electricity generation and transmission infrastructure require long lead times. This means that over the next two decades, BC Hydro must acquire an additional supply of "insurance power" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports.

Small Power Standing Offer

Achieving electricity self-sufficiency in British Columbia will require a range of new power sources to be brought on line. To help make this happen, this policy will direct BC Hydro to establish a Standing Offer Program with no quota to encourage small and clean electricity producers. Under the Standing Offer Program, BC Hydro will purchase directly from suppliers at a set price.

Eligible projects must be less than 10 megawatts in size and be clean electricity or high efficiency electricity cogeneration. The price offered in the standing offer contract would be based on the prices paid in the most recent BC Hydro energy call. This will provide small electricity suppliers with more certainty, bring small power projects into the system more quickly, and help achieve government's goal of maintaining a secure electricity supply. As well, BC Hydro will offer the same price to those in BC Hydro's Net Metering Program who have a surplus of generation at the end of the year.

Ensuring a Reliable Transmission Network

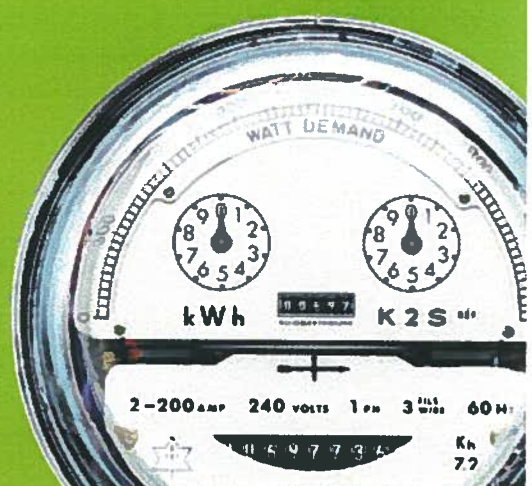
An important part of meeting the goal of self-sufficiency is ensuring a reliable transmission infrastructure is in place as additional power is brought on line. Transmission is a critical part of the solution as often new clean sources of electricity are located away from where the demand is. In addition, transmission investment is required to support economic growth in the province and must be planned and started in anticipation of future electricity needs given the long lead times required for transmission development. New and upgraded transmission infrastructure will be required to avoid congestion and to efficiently move the electricity across the entire power grid. Because our transmission system is part of a much larger, interconnected grid, we need to work with other jurisdictions to maximize the benefit of interconnection, remain consistent with evolving North American reliability standards, and ensure British Columbia's infrastructure remains capable of meeting customer needs.

BC HYDRO'S NET METERING PROGRAM: PEOPLE PRODUCING POWER

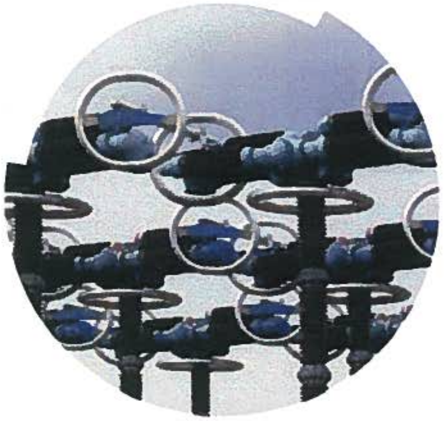
BC Hydro's Net Metering Program was established as a result of Energy Plan 2002. It is designed for customers with small generating facilities, who may sometimes generate more electricity than they require for their own use. A net metering customer's electricity meter will run backwards when they produce more electricity than they consume and run forward when they produce less than they consume.

The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced.

Net metering allows customers to lower their environmental impact and take responsibility for their own power production. It helps to move the province towards electricity self-sufficiency and expands clean electricity generation, making B.C.'s electricity supply more environmentally sustainable.



ELECTRICITY



In order for British Columbia to ensure the development of a secure and reliable supply of electricity, **The BC Energy Plan** provides policy direction to the BC Transmission Corporation to ensure that our transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand. This will include ensuring there is adequate transmission capacity, ongoing investments in technology and infrastructure and remaining consistent with evolving North American reliability standards.

BC Transmission Corporation Innovation and Technology

As the manager of a complex and high-value transmission grid, BC Transmission Corporation is introducing technology innovations that provide improvements to the performance of the system and allow for a greater utilization of existing assets, ensuring B.C. continues to benefit from one of the most advanced energy networks in the world. BC Transmission Corporation's innovation program focuses on increasing the power transfer capability of existing assets, extending the life of assets and improving system reliability and security. Initiatives include:

- System Control Centre Modernization Project: This project is consolidating system operations into a new control center and backup site and upgrading operating technologies with a modern management system that includes enhancements to existing applications to ensure the electric grid is operating reliably and efficiently. The backup site will take over complete operation of the electric grid if the main site is unavailable.
- Real-Time Phasors: British Columbia is among the first North American jurisdictions to incorporate phasor measurement into control centre operations. Phasors are highly accurate voltage, current and phase angle "snapshots" of the real-time state of the transmission system that enable system operators to monitor system conditions and identify any impending problems.
- Real-Time Rating: This is a temperature monitoring system which enables the operation of two 500 kilovolt submarine cable circuits at maximum capacity without overloading. The resulting increase in capacity is estimated to be up to 10 per cent, saving millions of dollars.
- Electronic Temperature Monitor Upgrades for Station Transformers: In this program, existing mechanical temperature monitors will be replaced with newer, more accurate electronic monitors on station transformers that allow transformers to operate to maximum capacity without overheating. In addition to improving performance, BC Transmission Corporation will realize reduced maintenance costs as the monitors are "self-checking."
- Life Extension of Transmission Towers: BC Transmission Corporation maintains over 22,000 steel lattice towers and is applying a special composite corrosion protection coating to some existing steel towers to extend their life by about 25 years.

Public Ownership

Public Ownership of BC Hydro and the BC Transmission Corporation

BC Hydro and the BC Transmission Corporation are publicly-owned crown corporations and will remain that way now and into the future. BC Hydro is responsible for generating, purchasing and distributing electricity. The BC Transmission Corporation operates, maintains, and plans BC Hydro's transmission assets and is responsible for providing fair, open access to the power grid for all customers. Both crowns are subject to the review and approvals of the independent regulator, the BC Utilities Commission.

BC Hydro owns the heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians. These heritage assets require maintenance and upgrades over time to ensure they continue to operate reliably and efficiently. Potential improvements to these assets, such as capacity additions at the Mica and Revelstoke generating stations, can make important contributions for the benefit of British Columbians.

Confirming the Heritage Contract in Perpetuity

Under the 2002 Energy Plan, a legislated heritage contract was established for an initial term of 10 years to ensure BC Hydro customers benefit from its existing low-cost resources. With **The BC Energy Plan**, government confirms the heritage contract in perpetuity to ensure ratepayers will continue to receive the benefits of this low-cost electricity for generations to come.

British Columbia's Leadership in Clean Energy

The BC Energy Plan will continue to ensure British Columbia has an environmentally and socially responsible electricity supply with a focus on conservation and energy efficiency.

British Columbia is already a world leader in the use of clean and renewable electricity, due in part to the foresight of previous generations who built our province's hydroelectric dams. These dams - now British Columbians' 'heritage assets' - today help us to enjoy 90 per cent clean electricity, one of the highest levels in North America.

All New Electricity Generation Projects Will Have Zero Net Greenhouse Gas Emissions

The B.C. government is a leader in North America when it comes to environmental standards. While British Columbia is a province rich in energy resources such as hydro electricity, natural gas and coal, the use of these resources needs to be balanced through effective use, preserving our environmental standards, while upholding our quality of life for generations to come. The government has made a commitment that all new electricity generation projects developed in British Columbia and connected to the grid will have zero net greenhouse gas emissions. In addition, any new electricity generated from coal must meet the more stringent standard of zero greenhouse gas emissions.

POLICY ACTIONS

PUBLIC OWNERSHIP

- **Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.**
- **Establish the existing heritage contract in perpetuity.**
- **Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.**

POLICY ACTIONS

REDUCING GREENHOUSE GAS EMISSIONS FROM ELECTRICITY

- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**
- **Require zero greenhouse gas emissions from any coal thermal electricity facilities.**
- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.**
- **No nuclear power.**

Zero Net Greenhouse Gas Emissions from Existing Thermal Generation Power Plants by 2016

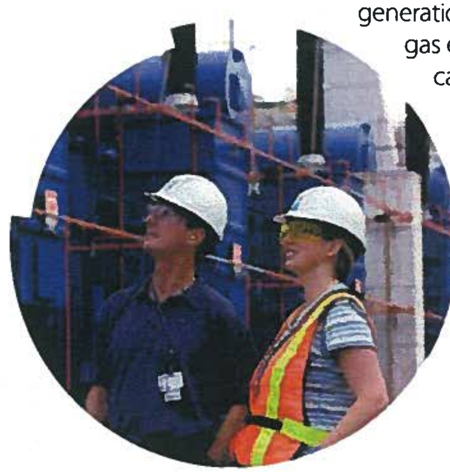
Setting a requirement for zero net emissions over this time period encourages power producers to invest in new or upgraded technology. For existing plants the government will set policy around reaching zero net emissions through carbon offsets from other activities in British Columbia. It clearly signals the government's intention to continue to have one of the lowest greenhouse gas emission electricity sectors in the world.

Ensure Clean or Renewable Electricity Generation Continues to Account For at Least 90 per cent of Total Generation

Currently in B.C., 90 per cent of electricity is from clean or renewable resources. **The BC Energy Plan** commits to maintaining this high standard which places us among the top jurisdictions in the world. Clean or renewable resources include sources of energy that are constantly renewed by natural processes, such as water power, solar energy, wind energy, tidal energy, geothermal energy, wood residue energy, and energy from organic municipal waste.

Zero Greenhouse Gas Emissions from Coal

The government is committed to ensuring that British Columbia's electricity sector remains one of the cleanest in the world and will allow coal as a resource for electricity generation when it can reach zero greenhouse gas emissions. Clean-coal technology with carbon sequestration is expected to become commercially available in the next decade. Therefore, the province will require zero greenhouse gas emissions from any coal thermal electricity facilities which can be met through capture and sequestration technology. British Columbia is the first Canadian jurisdiction to commit to using only clean coal technology for any electricity generated from coal.



Burrard Thermal Generating Station

A decision regarding the Burrard Thermal Natural Gas Generating Station is another action that is related to environmentally responsible electricity generation in British Columbia.

Even though it could generate electricity from Burrard Thermal, BC Hydro imports power primarily because the plant is outdated, inefficient and costly to run. However, Burrard Thermal still provides significant benefits to BC Hydro as it acts as a "battery" close to the Lower Mainland, and provides extra capacity or "reliability insurance" for the province's electricity supply. It also provides transmission system benefits that would otherwise have to be supplied through the addition of new equipment at Lower Mainland sub-stations.

By 2014, BC Hydro plans to have firm electricity to replace what would have been produced at the plant. Government supports BC Hydro's proposal to replace the firm energy supply from Burrard Thermal with other resources by 2014. However, BC Hydro may choose to retain the plant for "reliability insurance" should the need arise.

No Nuclear Power

As first outlined in Energy Plan 2002, government will not allow production of nuclear power in British Columbia.

Benefits to British Columbians

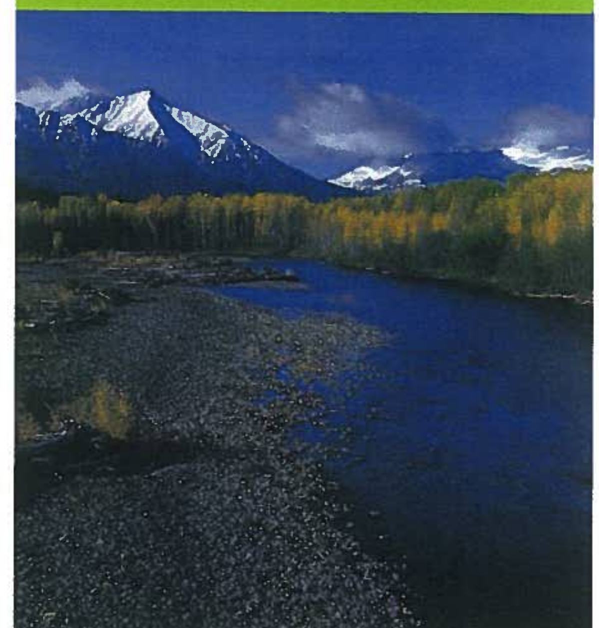
Clean or renewable electricity comes from sources that replenish over a reasonable time or have minimal environmental impacts. Today, demand for economically viable, clean, renewable and alternative energy is growing along with the world's population and economies. Consumers are looking for power that is not only affordable but creates minimal environmental impacts. Fortunately, British Columbia has abundant hydroelectric resources, and plenty of other potential energy sources.

Maintain our Electricity Competitive Advantage

British Columbians require a secure, reliable supply of competitively priced electricity now and in the future. Competitively priced power is also an incentive for investors to locate in British Columbia. It provides an advantage over other jurisdictions and helps sustain economic growth. We are fortunate that historic investments in hydroelectric assets provide electricity that is readily available, reliable, clean and inexpensive. By ensuring public ownership of BC Hydro, the heritage assets and the BC Transmission Corporation and confirming the heritage contract in perpetuity, we will ensure that ratepayers continue to receive the benefits of this low cost generation. Due to load growth and aging infrastructure, new investments will be required. Investments in maintenance and in some cases expansions can be a cost effective way to meet growth and reduce future rate increases.

CARBON OFFSETS AND HOW THEY REDUCE EMISSIONS

A carbon offset is an action taken directly, outside of normal operations, which results in reduced greenhouse gas emissions or removal of greenhouse gases from the atmosphere. Here's how it works: if a project adds greenhouse gases to the atmosphere, it can effectively subtract them by purchasing carbon offsets which are reductions from another activity. Government regulations to reduce greenhouse gases, including offsets, demonstrate leadership on climate change and support a move to clean and renewable energy.



ELECTRICITY

Government will establish a $25 million ***Innovative Clean Energy Fund.***

POLICY ACTIONS

BENEFITS TO BRITISH COLUMBIANS

- **Review BC Utilities Commissions' role in considering social and environmental costs and benefits.**
- **Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.**
- **Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.**
- **Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.**
- **Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.**

British Columbia must look for new, innovative ways to stay competitive. New technologies must be identified and nurtured, from both new and existing industries. By diversifying and strengthening our energy sector through the development of new and alternative energy sources, we can help ensure the province's economy remains vibrant for years to come.

Ensure Electricity is Secured at Competitive Prices

One practical way to keep rates down is to ensure utilities have effective processes for securing competitively priced power. As part of **The BC Energy Plan**, government will work with BC Hydro and parties involved to continue to improve the Call for Tender process for acquiring new generation. Fair treatment of both buyers and sellers of electricity will facilitate a robust and competitive procurement process. Government and BC Hydro will also look for ways to further recognize the value of intermittent resources, such as run-of- river and wind, in the acquisition process – which means that BC Hydro will examine ways to value separate projects together to increase the amount of firm energy calculated from the resources.

Rates Kept Low Through Powerex Trading of Electricity

Profits from electricity trade also contribute to keeping our electricity rates competitive. BC Hydro, through its subsidiary, Powerex, buys and sells electricity when it is advantageous to British Columbia's ratepayers. Government will continue to support capitalizing on electricity trading opportunities and will continue to allocate trade revenue to BC Hydro ratepayers to keep electricity rates low for all British Columbians.

BC Utilities Commissions' Role in Social and Environmental Costs and Benefits

The BC Energy Plan clarifies that social, economic and environmental costs are important for ensuring a suitable electricity supply in British Columbia. Government will review the BC Utilities Commissions' role in considering social, environmental and economic costs and benefits, and will determine how best to ensure these are appropriately considered within the regulatory framework.

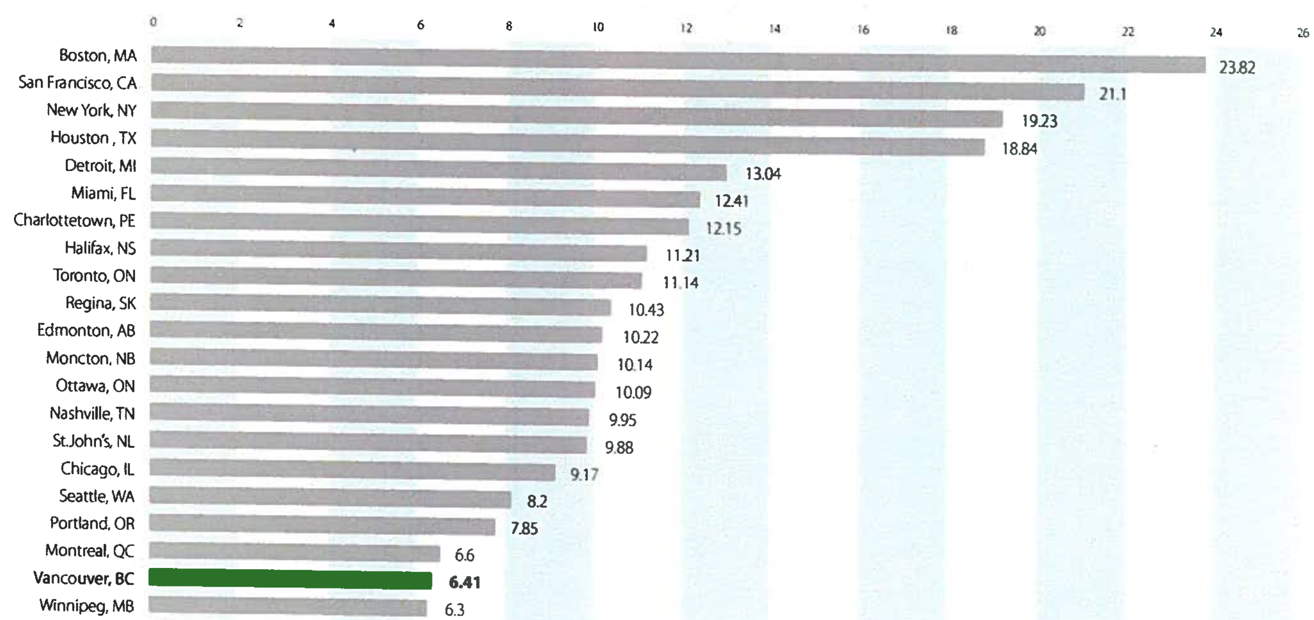
Bring Clean Power to Communities

British Columbia's electricity industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services. British Columbia's electricity industry already fosters economic development by implementing cost effective and reliable energy solutions in communities around the province. However, British Columbia covers almost one million square kilometres and electrification does not extend to all parts of our vast province.

Government and BC Hydro have established First Nation and remote community energy programs to implement alternative energy, energy efficiency, conservation and skills training solutions in a number of communities. The program focuses on expanding electrification services to as many as 50 remote and First Nations communities in British Columbia, enabling them to share in the benefits of a stable and secure supply of electricity. Government will put the policy framework in place and BC Hydro will implement the program over the next 10 years. The **Innovative Clean Energy Fund** can also support technological advancements to address the issue of providing a clean and secure supply of electricity to remote communities.

2006 Average Residential Electricity Price

Price (Canadian cents per kilowatt hour)



Source: Hydro Quebec comparison of Electricity Prices in Major North American Cities, April 2006

BRINGING CLEAN POWER TO ATLIN

Electricity in the remote community of Atlin in northwestern British Columbia is currently supplied by diesel generators. The First Nations and Remote Community Clean Energy Program is bringing clean power to Atlin.

The Taku Land Corporation, solely owned by the Taku River Tlingit First Nation will construct a two megawatt run-of-river hydroelectric project on Pine Creek, generating local economic benefits and providing clean power for Atlin. The Taku Land Corporation has entered into a 25 year Electricity Purchase Agreement with BC Hydro to supply electricity from the project to Atlin's grid. Over the course of the agreement, this will reduce greenhouse gas emissions by up to 150,000 tonnes as the town's diesel generators stand by.

The province is contributing $1.4 million to this $10 million project. This is the first payment from a $3.9 million federal contribution to British Columbia's First Nations and Remote Community Clean Energy Program. Criteria for federal funding included demonstrating greenhouse gas emissions reductions, cost-effectiveness, and partnerships with communities and industry.

Government will work with other agencies to maximize opportunities to develop, deploy and export British Columbia clean and alternative energy technologies.

POLICY ACTIONS

INVESTING IN INNOVATION

- **Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.**
- **Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.**
- **Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.**

Innovative Clean Energy Fund

British Columbia's increasing energy requirements and our ambitious greenhouse gas emission reduction and clean energy targets require greater investment and innovation in the area of alternative energy by both the public and private sector.

To lead this effort, the government will establish an **Innovative Clean Energy Fund** of $25 million to help promising clean power technology projects succeed. The fund will be established through a small charge on energy utilities. The Minister of Energy, Mines and Petroleum Resources will consult with the energy utilities on the implementation of this charge.

Proponents of projects that will be supported through the fund will be encouraged to seek additional contributions from other sources. Government's new **Innovative Clean Energy Fund** will help make British Columbia a world leader in alternative energy and power technology. It will solve some of B.C.'s pressing energy challenges, protect our environment, help grow the economy, position the province as the place international customers turn to for key energy and environmental solutions, and assist B.C. based companies to showcase their products to world wide markets.

Following the advice of the Premier's Technology Council and the Alternative Energy and Power Technology Task Force, the fund will focus strictly on projects that:

- Address specific British Columbia energy and environmental problems that have been identified by government.
- Showcase B.C. technologies that have a strong potential for international market demand in other jurisdictions because they solve problems that exist both in B.C. and other jurisdictions.
- Support pre-commercial energy technology that is new, or commercial technologies not currently used in British Columbia.
- Demonstrate commercial success for new energy technologies.

Some problems that the fund could focus on include:

- Developing reliable power solutions for remote communities-particularly helping First Nations communities reduce their reliance on diesel generation for electricity.
- Advance conservation technologies to commercial application.
- Finding ways to convert vehicles to cleaner alternative fuels.
- Increasing the efficiency of power transmission through future grid technologies.
- Expanding the opportunities to generate power using alternative fuels (e.g.mountain pine beetle wood).

The British Columbia Bioenergy Strategy: Growing Our Natural Energy Advantage

Currently, British Columbia is leading Canada in the use of biomass for energy. The province has 50 per cent of Canada's biomass electricity generating capacity. In 2005, British Columbia's forest industry self-generated the equivalent of $150 million in electricity and roughly $1.5 billion in the form of heat energy. The use of biomass has displaced some natural gas consumption in the pulp and paper sector. The British Columbia wood pellet industry also enjoys a one-sixth share of the growing European Union market for bioenergy feedstock. The province will shortly release a bioenergy strategy that will build upon British Columbia's natural bioenergy resource advantages, industry capabilities and academic strength to establish British Columbia as a world leader in bioenergy development.

British Columbia's plan is to lead the bioeconomy in Western Canada with a strong and sustainable bioenergy sector. This vision is built on two guiding principles:

- Competitive, diversified forest and agriculture sectors.
- Strengthening regions and communities.

The provincial Bioenergy Strategy is aimed at:

- Enhancing British Columbia's ability to become electricity self-sufficient.
- Fostering the development of a sustainable bioenergy sector.
- Creating new jobs.
- Supporting improvements in air quality.
- Promoting opportunities to create power from mountain pine beetle-impacted timber.
- Positioning British Columbia for world leadership in the development and commercial adoption of wood energy technology.
- Advancing innovative solutions to agricultural and other waste management challenges.
- Encouraging diversification in the forestry and agriculture industries.
- Producing liquid biofuels to meet Renewable Fuel Standards and displace conventional fossil fuels.

Generating Electricity from Mountain Pine Beetle Wood: Turning Wood Waste into Energy

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant impact on forestry-based communities and industries, and heightens forest fire risk. There is a great opportunity to convert the affected timber to bioenergy, such as wood pellets and wood-fired electricity generation and cogeneration.

Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.

MOUNTAIN PINE BEETLE INFESTATION: TURNING WOOD WASTE INTO ENERGY

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant economic impact on B.C.'s forestry industry and the many communities it helps to support and sustain. The forest fire risk to these communities has also risen as a result of their proximity to large stands of "beetle-killed" wood.

B.C. has developed a bioenergy strategy to promote new sources of sustainable and renewable energy in order to take advantage of the vast amounts of pine beetle-infested timber and other biomass resources. In the future, bioenergy will help meet our electricity needs, supplement conventional natural gas and petroleum supplies, maximize job and economic opportunities, and protect our health and environment.

The production of wood pellets is already a mature industry in British Columbia. Industry has produced over 500,000 tonnes of pellets and exported about 90 per cent of this product overseas in 2005, primarily to the European thermal power industry. Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for further electricity generation from wood residue and mountain pine beetle-infested timber.

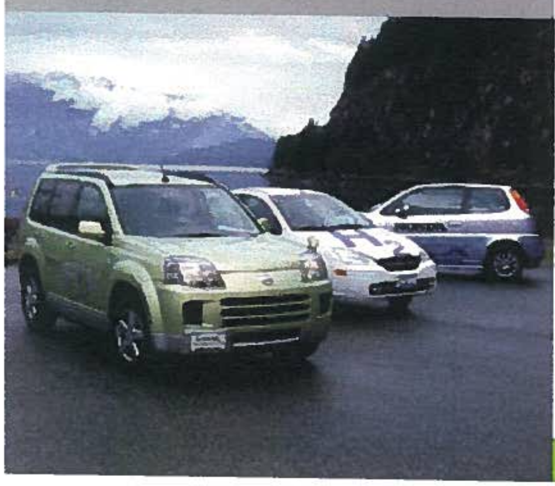
GOVERNMENT TO USE HYBRID VEHICLES ONLY

The provincial government is continuing the effort to reduce greenhouse gas emissions and overall energy consumption.

As part of this effort, government has more than tripled the size of its hybrid fleet since 2005 to become one of the leaders in public sector use of hybrid cars.

Hybrids emit much less pollution than conventional gas and diesel powered vehicles and thus help to reduce greenhouse gases in our environment. They can also be more cost-effective as fuel savings offset the higher initial cost.

As of 2007, all new cars purchased or leased by the B.C. government are to be hybrid vehicles. The province also has new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.



Addressing Greenhouse Gas Emissions from Transportation

The BC Energy Plan: A Vision for Clean Energy Leadership takes a first step to incorporate transportation issues into provincial energy policy. Transportation is a major contributor to climate change and air quality problems. It presents other issues such as traffic congestion that slows the movement of goods and people. The fuel we use to travel around the province accounts for about 40 per cent of British Columbia's greenhouse gas emissions. Every time we drive or take a vehicle that runs on fossil fuels, we add to the problem, whether it's a train, boat, plane or automobile. Cars and trucks are the biggest source of greenhouse gas emissions and contribute to reduced air quality in urban areas.

The government is committed to reducing greenhouse gas emissions from the transportation sector and has committed to adopting California's tailpipe emission standards from greenhouse gas emissions and champion the national adoption of these standards.

British Columbians want a range of energy options for use at home, on the road and in day-to-day life. Most people use gasoline or diesel to keep their vehicles moving, but there are other options that improve our air quality and reduce greenhouse gas emissions.

Natural gas burns cleaner than either gasoline or propane, resulting in less air pollution. Fuel cell vehicles are propelled by electric motors powered by fuel cells, devices that produce electricity from hydrogen without combustion.

Cars that run on blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants. Electricity can provide an alternative to gasoline vehicles when used in hybrids and electric cars.

By working with businesses, educational institutions, non-profit organizations and governments, new and emerging transportation technologies can be deployed more rapidly at home and around the world. British Columbia will focus on research and development, demonstration projects, and marketing strategies to promote British Columbia's technologies to the world.

Implementing a Five Per Cent Renewable Fuel Standard for Diesel and Gasoline

The BC Energy Plan demonstrates British Columbia's commitment to environmental sustainability and economic growth by taking a lead role in promoting innovation in the transportation sector to reduce greenhouse gas emissions, improve air quality and help improve British Columbians' health and quality of life in the future. The plan will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry. It will further support the federal action of increasing the ethanol content of gasoline to five per cent by 2010. The plan will also see the adoption of quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions. These renewable fuel standards are a major component and first step towards government's goal of reducing the carbon intensity of all passenger vehicles by 10 per cent by 2020.

Government will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.

A Commitment to Extend British Columbia's Ground-breaking Hydrogen Highway

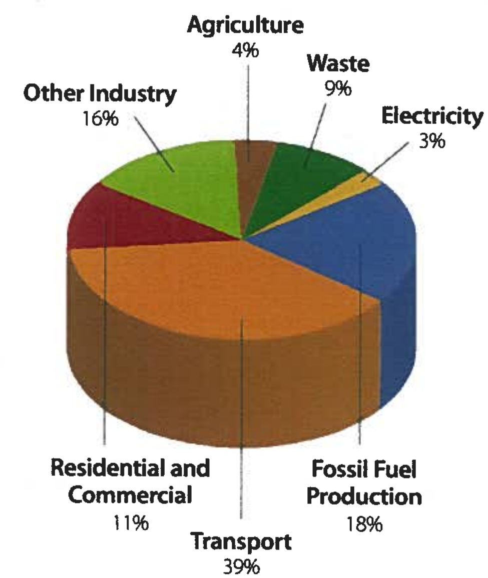
British Columbia is a world leader in transportation applications of the Hydrogen Highway, including the design, construction and safe operation of advanced hydrogen vehicle fuelling station technology. The Hydrogen Highway is a large scale, coordinated demonstration and deployment program for hydrogen and fuel cell technologies.

Vancouver's Powertech Labs established the world's first fast-fill, high pressure hydrogen fuelling station. The station anchors the Hydrogen Highway, which runs from Victoria through Surrey to Vancouver, North Vancouver, Squamish, and Whistler. Additional hydrogen fuelling stations are now in operation in Victoria and at the University of British Columbia.

The goal is to demonstrate and deploy various technologies and to one day see hydrogen filling stations around the province, serving drivers of consumer and commercial cars, trucks, and buses.

The unifying vision of the province's hydrogen and fuel cell strategy is to promote fuel cells and hydrogen technologies as a means of moving towards a sustainable energy future, increasing energy efficiency and reducing air pollutants and greenhouse gases. The Hydrogen Highway is targeted for full implementation by 2010. Canadian hydrogen and fuel cell companies have invested over $1 billion over the last five years, most of that in B.C. A federal-provincial partnership will be investing $89 million for fuelling stations and the world's first fleet of 20 fuel cell buses.

British Columbia will continue to be a leader in the new hydrogen economy by taking actions such as a fuel cell bus fleet deployment, developing a regulatory framework for micro-hydrogen applications, collaborating with neighbouring jurisdictions on hydrogen, and, in the long term, establishing a regulatory framework for hydrogen production, vehicles and fuelling stations.



B.C. Greenhouse Gas Emissions by Sector

(Based on 2004 data)
Source: Ministry of Environment

Cars and trucks are the biggest source of greenhouse gas emissions and reduce the quality of air in urban areas.

POLICY ACTIONS

ADDRESSING GREENHOUSE GAS EMISSIONS FROM TRANSPORTATION AND INCREASING INNOVATION

- **Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.**
- **Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.**
- **Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.**
- **Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.**

LOCALMOTION FUND: REDUCING AIR POLLUTION IN YOUR COMMUNITY

The province has committed $40 million over four years to help build cycling and pedestrian pathways, improve safety and accessibility, and support children's activity programs in playgrounds.

This fund will help local government shift to hybrid vehicle fleets and help retrofit diesel vehicles which will help reduce air pollution and ensure vibrant and environmentally sustainable communities. This investment will also include expansion of rapid transit and support fuel cell vehicles.

Vehicles that run on electricity, hydrogen and blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants.

Promote Energy Efficiency and Alternative Energy

It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province.

Environmental Leadership in Action

The BC Energy Plan: A Vision for Clean Energy Leadership complements other related cross-government initiatives that include supporting transportation demand management, reducing traffic congestion and better integrating land use and transportation planning. These plans include actions across a broad range of activities. Some key initiatives and recent announcements include:

- Extending the tax break on hybrid vehicle purchases beyond the current March 2008 deadline.
- Government to purchase hybrid vehicles exclusively.
- Reducing diesel emissions through new financial incentives to help municipalities shift to hybrid vehicle fleets and retrofit diesel vehicles with cleaner technologies.
- Green Ports:
  - Working with ports and the shipping sector to reduce emissions from their activities and marine vessels.
  - The Port of Vancouver has established idle reduction zones and has reduced truck emissions with its container reservation system which has reduced average wait times from two hours to approximately 20 minutes.
  - The port is also evaluating port-side electrification which would see vessels using shore-side electrical power while berthed rather than diesel power.
- Improving upon the monitoring and reporting of air quality information.
- Highway Infrastructure and Rapid Transit Infrastructure funding including the Gateway Program, the Border Infrastructure Program, high occupancy vehicle lanes, construction of the Rapid Transit Canada Line linking Richmond, the Vancouver International Airport and Vancouver, and the Rapid Transit Evergreen Line linking Burnaby to Coquitlam.
- Expanding the AirCare on the Road Program to the Lower Fraser Valley and other communities.
- Implementing the LocalMotion Program for capital projects to improve physical fitness and safety, reduce air pollution and meet the diverse needs of British Columbians.

A Choice of Electricity Options

The range of supply options, both large and small, for British Columbia include:

Bioenergy: Bioenergy is derived from organic biomass sources such as wood residue, agricultural waste, municipal solid waste and other biomass and may be considered a carbon-neutral form of energy, because the carbon dioxide released by the biomass when converted to energy is equivalent to the amount absorbed during its lifetime.

A number of bioenergy facilities operate in British Columbia today. Many of these are "cogeneration" plants that create both electricity and heat for on-site use and in some cases, sell surplus electricity to BC Hydro.

Reliability[1]: FIRM
Estimated Cost[5]: $75 – $91

Coal Thermal Power: The BC Energy Plan establishes a zero emission standard for greenhouse gas emissions from coal-fired plants. This will require proponents of new coal facilities to employ clean coal technology with carbon capture and sequestration to ensure there are no greenhouse gas emissions.

Reliability[1]: FIRM
Estimated Cost[5 6]: $67– $82

Geothermal: Geothermal power is electricity generated from the earth. Geothermal power production involves tapping into pockets of superheated water and steam deep underground, bringing them to the surface and using the heat to produce steam to drive a turbine and produce electricity. British Columbia has potential high temperature (the water is heated to more than 200 degrees Celsius) geothermal resources in the coastal mountains and lower temperature resources in the interior, in northeast British Columbia and in a belt down the Rocky Mountains. Geothermal energy's two main advantages are its consistent supply, and the fact that it is a clean, renewable source of energy.

Reliability[1]: FIRM
Estimated Cost[2]: $44 - $60

Hydrogen and Fuel Cell Technology:
British Columbia companies are recognized globally for being leaders in hydrogen and fuel cell technology for mobile, stationary and micro applications. For example, BC Transit's fuel cell buses are planned for deployment in Whistler in 2009.

Reliability[1]: FIRM
Estimated Cost[2]: n/a

[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant. The BC Energy Plan requires coal power to meet zero GHG emissions
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero GHG emissions for coal thermal power

GOVERNMENT'S COMMITMENT TO THE ENVIRONMENT – THE ENVIRONMENTAL ASSESSMENT PROCESS

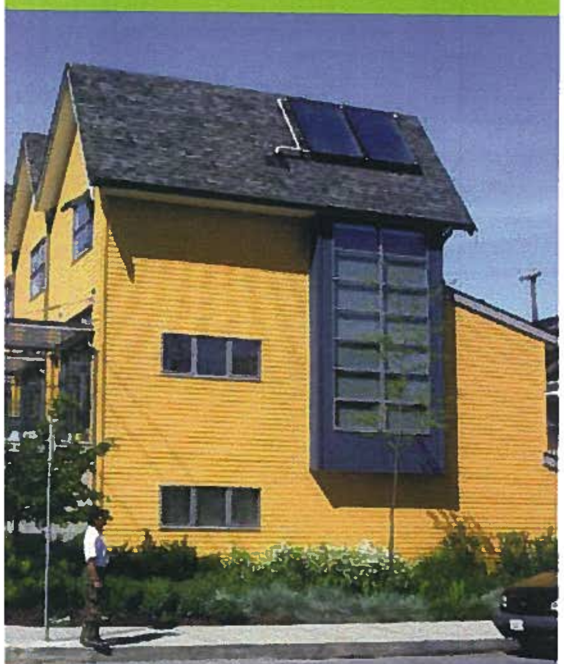
The environmental assessment process in British Columbia is an integrated review process for major projects that looks at potential environmental, community and First Nation, health and safety, and socioeconomic impacts. Through the environmental assessment process, the potential effects of a project are identified and evaluated early, resulting in improved project design and helping to avoid costly mistakes for proponents, governments, local communities and the environment.

An assessment is begun when a proposed project that meets certain criteria under the ***Environmental Assessment Act*** makes an application for an environmental assessment certificate. Each assessment will usually include an opportunity for all interested parties to identify issues and provide input; technical studies of the relevant environmental, social, economic, heritage and/or health effects of the proposed project; identification of ways to prevent or minimize undesirable effects and enhance desirable effects; and consideration of the input of all interested parties in compiling the assessment findings and making decisions about project acceptability. The review is concluded when a decision is made to issue or not issue an environmental assessment certificate. Industrial, mining, energy, water management, waste disposal, food processing, transportation and tourist destination resort projects are generally subject to an environmental assessment.

ELECTRICITY CHOICES

WHAT IS THE DIFFERENCE BETWEEN FIRM AND INTERMITTENT ELECTRICITY?

Firm electricity refers to electricity that is available at all times even in adverse conditions. The main sources of reliable electricity in British Columbia include large hydroelectric dams, and natural gas. This differs from intermittent electricity, which is limited or is not available at all times. An example of intermittent electricity would be wind which only produces power when the wind is blowing.



Large Hydroelectric Dams: The chief advantage of a hydro system is that it provides a reliable supply with both dependable capacity and energy, and a renewable and clean source of energy. Hydropower produces essentially no carbon dioxide.

Site C is one of many resource options that can help meet BC Hydro's customers' electricity needs. No preferred option has been selected at this time; however; it is recognized that the Province will need to examine opportunities for some large projects to meet growing demand.

As part of **The BC Energy Plan**, BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known. The purpose of this step is to engage the various parties up front to obtain input for the proposed engagement process. The decision-making process on Site C includes public consultation, environmental impact assessments, obtaining a Certificate of Public Convenience and Necessity, obtaining an Environmental Assessment Certificate and necessary environmental approvals, and approval by Cabinet.

Reliability[1]: FIRM
Estimated Cost[2]: \$43 - \$62

Natural Gas: Natural gas is converted into electricity through the use of gas fired turbines in medium to large generating stations; particularly high efficiencies can be achieved through combining gas turbines with steam turbines in the combined cycle and through reciprocating engines and mini and macro turbines. Combined cycle power generation using natural gas is the cleanest source of power available using fossil fuels. Natural gas provides a reliable supply with both dependable capacity and firm energy.

Reliability[1]: FIRM
Estimated Cost[2 6]: \$48 - \$100

Small Hydro: This includes run-of-river and micro Hydro. These generate electricity without altering seasonal flow characteristics. Water is diverted from a natural watercourse through an intake channel and pipeline to a powerhouse where a turbine and generator convert the kinetic energy in the moving water to electrical energy.

Twenty-nine electricity purchase agreements were awarded to small waterpower producers by BC Hydro in 2006. These projects will generate approximately 2,851 gigawatt hours of electricity annually (equivalent to electricity.consumed by 285,000 homes in British Columbia). There are also 32 existing small hydro projects in British Columbia that generate 3,500 gigawatt hours (equivalent to electricity consumed by 350,000 homes in British Columbia).

Reliability[1]: INTERMITTENT
Estimated Cost[3]: \$60 – \$95

Solar: With financial support from the Ministry of Energy, Mines and Petroleum Resources, the "Solar for Schools" program has brought clean solar photovoltaic electricity to schools in Vernon, Fort Nelson, and Greater Victoria.

The BC Sustainable Energy Association is leading a project which targets installing solar water heaters on 100,000 rooftops across British Columbia.

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $700 - $1700

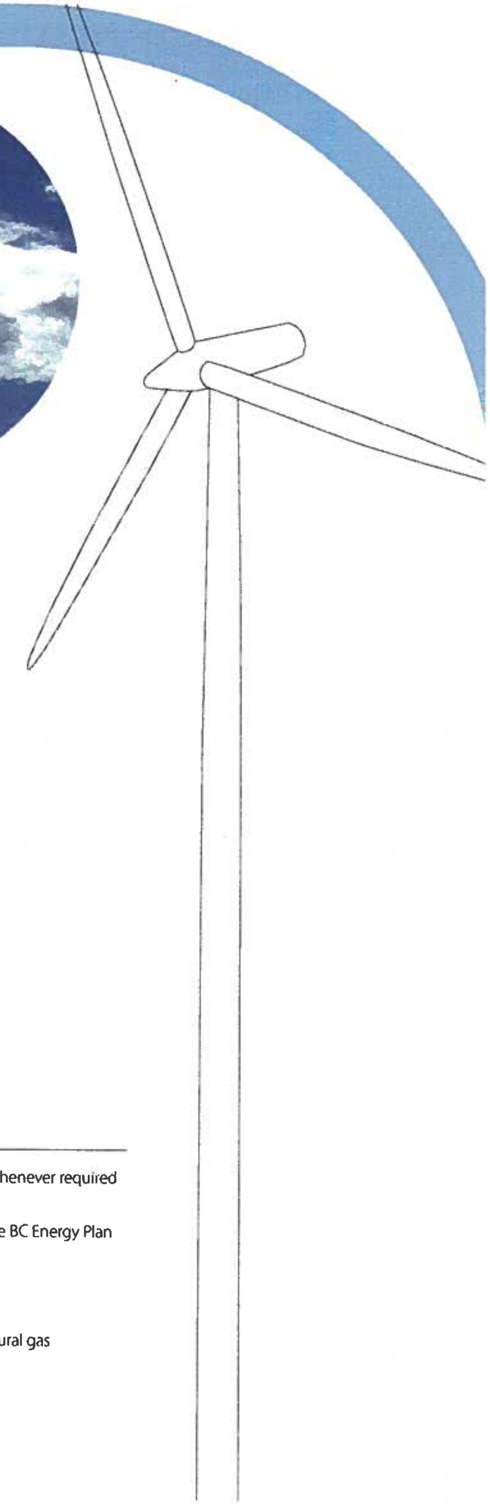
Tidal Energy: A small demonstration project has been installed at Race Rocks located west-southwest of Victoria. The Lester B. Pearson College of the Pacific, the provincial and federal government, and industry have partnered to install and test a tidal energy demonstration turbine at Race Rocks. The project will generate about 77,000 kilowatt hours on an annual basis (equivalent to electricity consumed by approximately eight homes).

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $100 - $360

Wind: British Columbia has abundant, widely distributed wind energy resources in three areas: the Peace region in the Northeast; Northern Vancouver Island; and the North Coast. Wind is a clean and renewable source that does not produce air or water pollution, greenhouse gases, solid or toxic wastes.

Three wind generation projects have been offered power purchase contracts in BC Hydro's 2006 Open Call for Power. These three projects will have a combined annual output of 979 gigawatt hours of electricity (equivalent to electricity consumed by 97,900 homes).

Reliability[1]: INTERMITTENT
Estimated Cost[5]: $71 – $74



[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant.
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero net GHG emissions for natural gas

RACE ROCKS TIDAL ENERGY PROJECT

Announced in early 2005, this demonstration project between the provincial and federal governments, industry, and Pearson College is producing zero emission tidal power at the Race Rocks Marine Reserve on southern Vancouver Island. Using a current-driven turbine submerged below the ocean surface, the project is producing about 77,000 kilowatt hours of electricity per year, enough to meet the needs of approximately eight households. The knowledge gained about tidal energy will help our province remain at the forefront of clean energy generation technology.

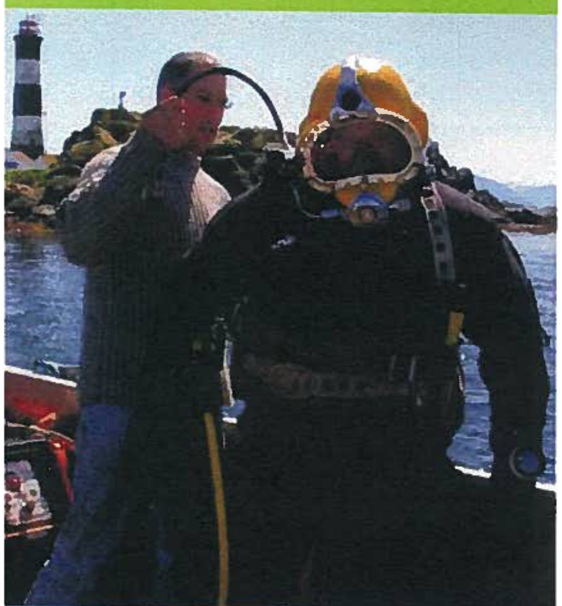


Table 1: Summary of Resource Options

Description	Estimated Cost [1] $ /megawatt hour	Reliable[2]	Greenhouse gas emissions[3] tonnes per gigawatt hour
Energy conservation/ efficiency	32 – 76	Yes	0
Large hydroelectric	43 – 62	Yes	0
Natural gas	48 – 100[8]	Yes	0 – 350[4 8]
Coal	67 – 82[9 10]	Yes	0 – 855[5 9]
Biomass	75 – 91[10]	Yes	0 – 500[6]
Geothermal	44 – 60	Yes	0 – 10
Wind	71 – 74[10]	Depends on the availability and speed of wind	0
Run-of-river small hydro	60 – 95[10]	Depends on the flow of water, which varies throughout the year	0
Ocean (wave and tidal)	100 – 360[7]	Future supply option which has great potential for British Columbia	0
Solar	700 – 1700[7]	Depends on location, cloud cover, season, and time of day	0

1 Source: BC Hydro's 2006 Integrated Electricity Plan Volume 1 of 2, page 5-6
2 Reliability refers to energy that can be depended on to be available whenever required
3 Source: BC Hydro's 2006 Integrated Electricity Plan, Volume 2 of 2, Appendix F page 5-14 and Table 10-2
4 Based on a 250 MW combined cycle gas turbine plant
5 Based on a 500 MW supercritical pulverized coal combustion unit
6 GHG are 0 for wood residue and landfill gas. GHG is 500 tonnes per gigawatt hour for municipal solid waste
7 Source: BC Hydro's 2004 Integrated Electricity Plan, page 69
8 The BC Energy Plan requires natural gas plants to offset to zero net greenhouse gas emissions. These costs do not reflect the costs of zero net GHG emissions
9 The BC Energy Plan requires zero greenhouse gas emissions from any coal thermal electricity facilities The costs do not include the costs of requiring zero emissions from coal thermal power
10 Source: BC Hydro's F2006 Open Call for Power Report

The majority of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation by all British Columbians and new electricity from independent power producers.

British Columbia's Strength in Electricity Diversity

British Columbia is truly fortunate to have a wide variety of future supply options available to meet our growing demand for energy. A cost effective way to meet that demand is to conserve energy and be more energy efficient. However, British Columbia will still need to bring new power on line to meet demand growth in the years ahead. In order to ensure we have this critical resource available to British Columbians when they need it, government will be looking to secure a range of made-in-B.C. power to serve British Columbians in the years ahead.

Government's goal is to encourage a diverse mix of resources that represent a variety of technologies. Some resource technologies, such as large and small hydro, thermal power, wind and geothermal provide well-established, commercially available sources of electricity. Other emerging technologies that are not yet widely used include large ocean wave and tidal power, solar, hydrogen and advanced coal technologies.

2004 Total Electricity Production by Source (% of total)

	Other Renewables	Hydro Electric	Nuclear	Waste and Biomass	Natural Gas	Diesel Oil	Coal	TOTAL
British Columbia	**0.0**	**92.8**	**0.0**	**1.0**	**6.0**	**0.2**	**0.0**	**100**
Alberta	2.3	4.4	0.0	0.0	12.0	2.6	78.7	100
Australia	0.3	6.9	0.0	0.6	12.3	0.70	79.2	100
California	10.7	17.0	14.5	0.0	37.7	0.0	20.1	100
Denmark	16.3	0.1	0.0	8.8	24.7	4.0	46.1	100
Finland	0.4	17.6	26.5	12.4	14.9	0.7	27.5	100
France	0.2	11.3	78.3	1.0	3.2	1.0	5.0	100
Germany	4.2	4.5	27.1	2.6	10.0	1.6	50.0	100
Japan	0.4	9.5	26.1	1.9	22.6	12.3	27.2	100
Norway	0.3	98.8	0.0	0.5	0.3	0.0	0.1	100
Ontario	1.8	24.8	49.7	0.0	5.2	0.5	18.0	100
Oregon	2.3	64.4	0.0	0.0	26.3	0.1	6.9	100
Quebec	0.7	94.5	3.2	0.0	0.1	1.5	0.0	100
United Kingdom	0.5	1.9	20.2	2.1	40.3	1.2	33.8	100
Washington	2.3	70.0	8.8	0.0	8.6	0.1	10.2	100

SHARING SOLUTIONS ON ELECTRICITY

The BC Energy Plan has a goal that most of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation and energy efficiency by all British Columbians, coupled with generation by independent power producers. However, these new projects take time to plan and implement. In addition, many of these sources provide limited amounts of firm supply. The province will also need to consider options for new, large scale sources to meet forecasted demand growth in the next 10 to 20 years. Large scale options could include Site C, large biomass facilities, clean coal or natural gas plants. As with all large scale undertakings, these kinds of projects will require years of lead time to allow for careful planning, analysis, consultation and construction.

Perhaps the biggest challenge facing British Columbians is simply to begin choosing our electricity future together. Demand for electricity is projected to grow by up to 45 per cent over the next 20 years. To meet this projected growth we will need to conserve more, and obtain more electricity from small power producers and large projects. Given the critical importance of public participation and stakeholder involvement in addressing the challenges and choices of meeting our future electricity needs, government and BC Hydro will seek and share solutions.

Rapid expansion of our energy sector means a growing number of permanent, well-paying employment opportunities are available.

Taking Action to Meet the Demand for Workers

The energy sector has been a major contributor to British Columbia's record economic performance since 2001. **The BC Energy Plan** focuses on four under-represented groups that offer excellent employment potential: Aboriginal people, immigrants, women and youth.

At the same time, the energy sector must overcome a variety of skills training and labour challenges to ensure future growth.

These challenges include:

- An aging workforce that upon retirement will leave a gap in experience and expertise.
- Competition for talent from other jurisdictions.
- Skills shortages among present and future workers.
- Labour market information gaps due to a lack of in-depth study.
- The need to coordinate immigration efforts with the federal government.
- The need for greater involvement of under-represented energy sector workers such as Aboriginal people, immigrants, women, and youth.
- A highly mobile workforce that moves with the opportunities.
- The need to improve productivity and enhance competitiveness.

Innovative, practical and timely skills training, and labour management is required to ensure the energy sector continues to thrive. As part of **The BC Energy Plan**, government will work collaboratively with industry, communities, Aboriginal people, education facilities, the federal government and others to define the projected demand for workers and take active measures to meet those demands.

Attract Highly Skilled Workers

Demographics show that those born at the height of the baby boom are retired or nearing retirement, leaving behind a growing gap in skills and expertise. Since this phenomenon is taking place in most western nations, attracting and retaining skilled staff is highly competitive.

To ensure continued energy sector growth, we need to attract workers from outside the province, particularly for the electricity, oil and gas, and heavy construction industries where the shortage is most keenly felt. At this time, a significant increase in annual net migration of workers from other provinces and from outside Canada is needed to complement the existing workforce.

Government and its partners are developing targeted plans to attract the necessary workers. These plans will include marketing and promoting energy sector jobs as a career choice.

Develop a Robust Talent Pool of Workers

It is vital to provide the initial training to build a job-ready talent pool in British Columbia, as well as the ongoing training employees need to adapt to changing energy sector technologies, products and requirements. We can ensure a thriving pool of talent in British Columbia by retraining skilled employees who are without work due to downturns in other industries. Displaced workers from other sectors and jurisdictions may require some retraining and new employees may need considerable skills development.

Another way to help ensure there are enough skilled energy sector workers in the years ahead is to educate and inform young people today. By letting high school students know about the opportunities, they can consider their options and make the appropriate training and career choices. Government will work to enhance information relating to energy sector activities in British Columbia's school curriculum in the years ahead.

Retain Skilled Workers

Around the world, energy facility construction and operations are booming, creating fierce, global competition for skilled workers. While British Columbia has much to offer, it is critical that our jurisdiction presents a superior opportunity to these highly skilled and mobile workers. That is why we need to ensure our workplaces are safe, fair and healthy and our communities continue to offer an unparalleled lifestyle with high quality health care and education, affordable housing, and readily available recreation opportunities in outstanding natural settings.

Inform British Columbians

To be effective in filling energy sector jobs with skilled workers, British Columbians need to be informed and educated about the outstanding opportunities available. As part of **The BC Energy Plan**, a comprehensive public awareness and education campaign based on sound labour market analysis will reach out to potential energy sector workers. This process will recognize and address both the potential challenges such as shift work and remote locations as well as the opportunities, such as obtaining highly marketable skills and earning excellent compensation.

OIL AND GAS

Be Among the Most Competitive Oil and Gas Jurisdictions in North America

Since 2001, British Columbia's oil and gas sector has grown to become a major force in our provincial economy, employing tens of thousands of British Columbians and helping to fuel the province's strong economic performance. In fact, investment in the oil and gas sector was $4.6 billion in 2005. The oil and gas industry contributes approximately $1.95 billion annually or seven per cent of the province's annual revenues.

The BC Energy Plan is designed to take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas sector in British Columbia. With a healthy, competitive oil and gas sector comes the opportunity to create jobs and build vibrant communities with increased infrastructure and services, such as schools and hospitals. Of particular importance is an expanding British Columbia-based service sector.

There is a lively debate about the peak of the world's oil and gas production and the impacts on economies, businesses and consumers. A number of countries, such as the UK, Norway and the USA, are experiencing declining fossil fuel production from conventional sources. Energy prices, especially oil prices have increased and are more volatile than in the past. As a result, the way energy is produced and consumed will change, particularly in developed countries.

The plan is aimed at enhancing the development of conventional resources and stimulating activity in relatively undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources such as as tight gas, shale gas, and coalbed gas. The plan will further efforts to work with the federal government, communities and First Nations to advance offshore opportunities.

The challenge for British Columbia in the future will be to continue to find the right balance of economic, environmental and social priorities to allow the oil and gas sector to succeed, while protecting our environment and improving our quality of life.

The New Relationship and Oil and Gas

Working together with local communities and First Nations, the provincial government will continue to share in the many benefits and opportunities created through the development of British Columbia's oil and gas resources.

Government is working to ensure that oil and gas resource management includes First Nations' interests, knowledge and values. Government has recently concluded consultation agreements for oil and gas resource development with First Nations in Northeast British Columbia. These agreements increase clarity in the process and will go a long way to enhancing our engagement with these First Nations.

Government will continue to pursue opportunities to share information and look for opportunities to facilitate First Nations' employment and participation in the oil and gas industry to ensure that Aboriginal people benefit from the continued growth and development of British Columbia's resources.

POLICY ACTIONS

ENVIRONMENTALLY RESPONSIBLE OIL AND GAS DEVELOPMENT

- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**
- **Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.**
- **Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.**
- **Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.**

***The BC Energy Plan** adopts a triple bottom line approach to competitiveness, with an attractive investment climate, environmentally sustainable development of B.C.'s abundant resources, and by benefiting communities and First Nations.*

While striving to be among the most competitive oil and gas jurisdictions in North America, the province will focus on maintaining and enhancing its strong competitive environment for the oil and gas industry. This encompasses the following components:

- A competitive investment climate.
- An abundant resource endowment.
- Environmental responsibility.
- Social responsibility.

Leading in Environmentally and Socially Responsible Oil and Gas Development

The BC Energy Plan emphasizes conservation, energy efficiency, and the environmental and socially responsible management of the province's energy resources. It outlines government's efforts to meet this objective by working collaboratively with involved and interested parties, including affected communities, landowners, environmental groups, First Nations, the regulator (the Oil and Gas Commission), industry groups and others. Policy actions will support ways to address air emissions, impacts on land and wildlife habitat, and water quality.

The oil and gas sector in British Columbia accounts for approximately 18 per cent of greenhouse gas air emissions in the province. The main sources of air emissions from the oil and gas sector are flaring, fugitive gases, gas processing and compressor stations. While these air emissions have long been part of the oil and gas sector, they have also been a source of major concern for oil and gas communities.

Eliminate Flaring from Oil and Gas Producing Wells and Production Facilities By 2016

Through **The BC Energy Plan**, government has committed to eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011. In addition, government will adopt policies to reduce natural gas flaring and venting at test sites and pipelines, and encourage compressor station efficiency to cut back emissions. Government will also explore opportunities and new technologies for safe, underground disposal of carbon dioxide or sequestration from oil and gas facilities. Sequestration is considered a cost effective mitigation strategy in reducing carbon dioxide emissions.

Enhance Carbon Dioxide Sequestration in British Columbia

British Columbia is a member of the Plains CO2 Reduction (PCOR) Partnership composed of nearly 50 private and public sector groups from nine states and three Canadian provinces that is assessing the technical and economic feasibility of capturing and storing carbon dioxide emissions from stationary sources in western sedimentary basins.

B.C. is also a member of the West Coast Regional Carbon Sequestration Partnership, made up of west coast state and provincial government ministries and agencies. This partnership has been formed to pursue carbon sequestration opportunities and technologies.

To facilitate and foster innovation in sequestration, government will develop market oriented requirements with a graduated schedule. In consultation with stakeholders, a timetable will be developed along with increasing requirements for sequestration.

BRITISH COLUMBIA COMPANIES RECOGNIZED AS WORLD ENERGY TECHNOLOGY INNOVATORS

The leadership of British Columbian companies can be seen in all areas of the energy sector through innovative, industry leading technologies.

Production of a new generation of chemical injection pump for use in the oil and gas industry is beginning. The pumps, developed and built in British Columbia, are the first solar powered precision injection pumps available to the industry. They will reduce emissions by replacing traditional gas powered injection systems for pipelines.

Other solar technologies developed in British Columbia provide modular power supplies in remote locations all over the globe for marine signals, aviation lights and road signs.

Roads in B.C. and around the world are hosting demonstrations of fuel cell vehicles built with British Columbia technology. Thanks to the first high pressure hydrogen fuelling station in the world, compatible fuel cell vehicles in B.C. can carry more fuel and travel farther than ever before.

The **Innovative Clean Energy Fund** will help to build B.C.'s technology cluster and keep us at the forefront of energy technology development.

OIL AND GAS

Government will work to improve oil and gas tenure policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval.

POLICY ACTIONS

OFFSHORE OIL AND GAS DEVELOPMENT

- **Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.**
- **Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.**
- **Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.**
- **Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.**

Environmental Stewardship Program

In 2004, the Ministry of Energy, Mines and Petroleum Resources initiated the Oil and Gas Environmental Stewardship Program having two components: the Environmental Policy Program and the Environmental Resource Information Project. The Environmental Policy Program identifies and mitigates environmental issues in the petroleum sector focusing on policy development in areas such as environmental waste management, habitat enhancement, planning initiatives, wildlife studies for oil and gas priority areas and government best management practices. Some key program achievements include the completion of guidelines for regulatory dispersion modeling, research leading to the development of soil quality guidelines for soluble barium, a key to northern grasses and their restorative properties for remediated well sites, and moose and caribou inventories in Northeast British Columbia.

The Environmental Resource Information Project is dedicated to increasing opportunities for oil and gas development, through the collection of necessary environmental baseline information. These projects are delivered in partnership with other agencies, industry, communities and First Nations.

The BC Energy Plan enhances the important Oil and Gas Environmental Stewardship Program. This will improve existing efforts to manage waste and preserve habitat, and will establish baseline data as well as development and risk mitigation plans for environmentally sensitive areas. Barriers need to be identified and steps taken for remediation, progressive reclamation, and waste management.

Best Coalbed Gas Practices in North America

Government will continue to encourage coalbed gas development with the intent of demonstrating that British Columbia is a leading socially and environmentally responsible coalbed gas developing jurisdiction. Coalbed gas, also known as coalbed methane, is natural gas found in coal seams. It is one of the cleanest burning of all fossil fuels. Proponents wanting to develop coalbed gas must adopt the following best practices:

- Fully engage local communities and First Nations in all stages of development.
- Use the most advanced technology and practices that are commercially viable to minimize land and aesthetic disturbances.
- Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
- Meet any other conditions the Oil and Gas Commission may apply.
- Demonstrate the company's previous experience with coalbed gas development, and information must be made publicly available as to how the company plans to meet and be accountable for these best practices.

Ensuring Offshore Oil and Gas Resources are Developed in a Scientifically Sound and Environmentally Responsible Way

The BC Energy Plan includes actions related to the province's offshore oil and gas resources. Since 1972, Canada and British Columbia have each had a moratorium in place on offshore oil and gas exploration and development. With advanced technology and positive experiences in other jurisdictions, a compelling case exists for assessing British Columbia's offshore resource potential.

Government will work with coastal communities, First Nations, the federal government, environmental organizations, and others to ascertain the benefits and address the concerns associated with offshore oil and gas development.

Maintaining B.C.'s Competitive Advantage as an Oil and Gas Jurisdiction

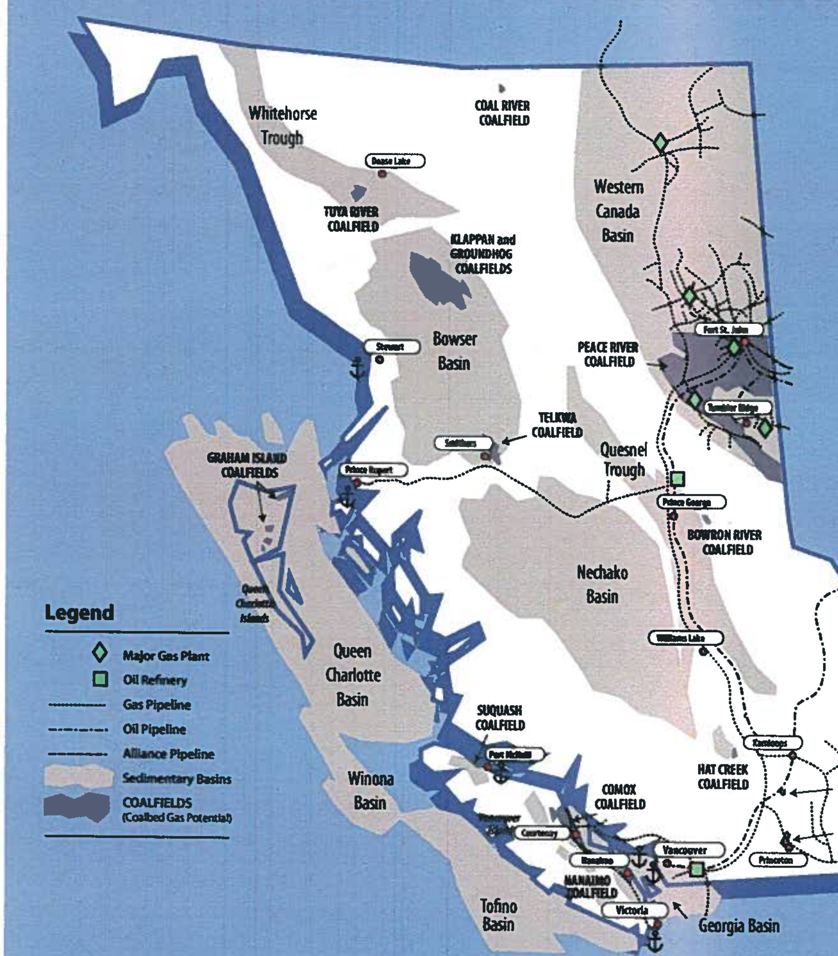
British Columbia's oil and gas industry is thriving thanks to high resource potential, industry and service sector expertise, and a competitive investment climate that includes a streamlined regulatory environment. To attract additional investment in British Columbia's oil and gas industry, we need to compete aggressively with other jurisdictions that may offer lower taxes or other investment incentives.

Another key way to be more competitive is by spurring activity in underdeveloped areas while heightening activity in the northeast, where our natural gas industry thrives. The province will work with industry to develop new policies and technologies for enhanced resource recovery making, it more cost-effective to develop British Columbia's resources.

By increasing our competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

British Columbia's oil and gas industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services.

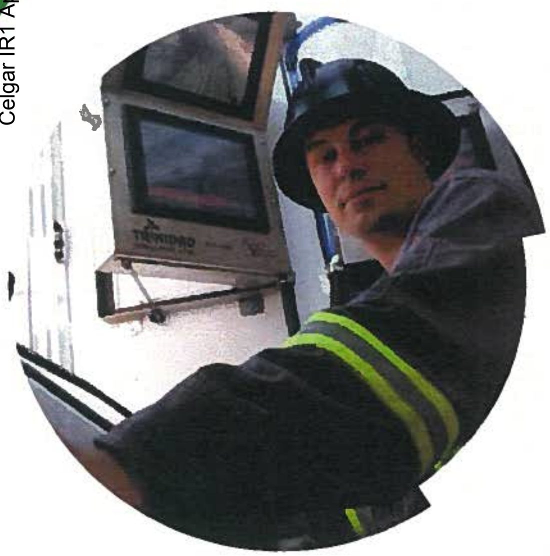
BC OIL AND GAS UNDISCOVERED RESOURCE ESTIMATES



Conventional	
Gas	98.0 Tcf
Oil	17.6 B bbl
Unconventional Gas	
Coalbed gas	84.0 Tcf
Tight gas	300 Tcf
Shale gas	250 Tcf
Offshore Gas	41.8 Tcf
Offshore Oil	9.8 B bbl
Gas Hydrates	113-847 Tcf

Tcf – Trillion cubic feet
B bbl – Billion Barrels

OIL AND GAS



British Columbia's Enormous Natural Gas Potential

The oil and gas sector will continue to play an important role in British Columbia's future energy security. Our province has enormous natural gas resource potential and opportunities for significant growth. **The BC Energy Plan** facilitates the development of B.C.'s resources.

British Columbia has numerous sedimentary basins, which contain petroleum and natural gas resources. In north-eastern British Columbia, the Western Canada Sedimentary Basin is the focus of our thriving natural gas industry. The potential resources in the central and northern interior of the province, the Nechako and Bowser Basins and Whitehorse Trough, have gone untapped.

The delayed evaluation and potential development of these areas is largely due to geological and physical obstructions that make it difficult to explore in the area. Volcanic rocks that overlay the sedimentary package combined with complex basin structures, have hindered development.

The BC Energy Plan is aimed at enhancing the development of conventional resources and stimulating activity in undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources and take a more stringent approach on coalbed gas to meet higher environmental standards.

Attracting Investment and Developing our Oil and Gas Resources

The BC Energy Plan promotes competitiveness by setting out a number of important regulatory and fiscal measures including: monitoring British Columbia's competitive ranking, considering a Net Profit Royalty Program, promoting a B.C. service sector, harmonizing and streamlining regulations, and developing a Petroleum Registry to examine royalty and tenure incentives, and undertaking geoscience programs.

Establishment of a Petroleum Registry

The establishment of a petroleum registry that functions as a central database will improve the quality and management of key volumetric, royalty and infrastructure information associated with British Columbia's oil and gas industry and promote competition while providing transparency around oil and gas activity.

NEEMAC: SUCCESS THROUGH COMMUNICATION

As energy, mining and petroleum resource development increases in northeast B.C., so too does the need for input from local governments, First Nations, community groups, landowners and other key stakeholders. In 2006, the Northeast Energy and Mines Advisory Committee (NEEMAC) was created to provide an inclusive forum for representative organizations to build relationships with each other, industry and government to provide input on Ministry policy, and recommend innovative solutions to stakeholder concerns.

Since its creation, NEEMAC has identified and explored priority concerns, and is beginning to find balanced solutions related to environmental, surface disturbance, access and landowner rights issues. The Ministry is committed to implementing recommendations that represent the broad interests of community, industry and government and expects that the committee will continue to provide advice on energy, mining and petroleum development issues in support of **The BC Energy Plan**.

An opportunity to increase competitiveness exists in British Columbia's Interior Basins – namely the Nechako, Bowser and Whitehorse Basins – where considerable resource potential is known to exist.

Increasing Access

In addition to regulatory and fiscal mechanisms, the plan addresses the need for improving access to resources. Pipelines and road infrastructure are critical factors in development and competitiveness. **The BC Energy Plan** calls for new investment in public roads and other infrastructure. It will see government establish a clear, structured infrastructure royalty program, combining road and pipeline initiatives and increasing development in under-explored areas that have little or no existing infrastructure.

Developing Conventional and Unconventional Oil and Gas Resources

To support investment in exploration, **The BC Energy Plan** calls for partnerships in research and development to establish reliable regional data, as well as royalty and tenure incentives. The goal is to attract investment, create well-paying jobs, boost the regional economy and produce economic benefits for all British Columbians. We can be more competitive by spurring activity in underdeveloped areas while heightening activity in the northeast where our natural gas industry thrives. The plan advocates working with industry to develop new policies and technology to enhance resource recovery, including oil in British Columbia.

Improve Regulations and Research

The province remains committed to continuous improvement in the regulatory regime and environmental management of conventional and unconventional oil and gas resources. The opportunities for enhancing exploration and production of tight gas, shale gas, and coalbed gas will also be assessed and supported by geoscience research and programs. **The BC Energy Plan** calls for collaboration with other government ministries, agencies, industry, communities and First Nations to develop the oil and gas resources in British Columbia.

Focus on Innovation and Technology Development

The BC Energy Plan also calls for supporting the development of new oil and gas technologies. This plan will lead British Columbia to become an internationally recognized centre for technological advancements and commercialization, particularly in environmental management, flaring, carbon sequestration and hydrogeology. The service sector has noted it can play an important role in developing and commercializing new technologies; however, the issue for companies is accessing the necessary funds.

THE HUB OF B.C.'S OIL AND GAS SECTOR

Oil and gas is benefiting all British Columbians - not just those living in major centres. Nowhere is this more apparent than in booming Fort St. John, which has rapidly become the oil and gas hub of the province. Since 2001, more than 1,400 people have moved to the community, an increase of 6.3 per cent and two per cent faster growth than the provincial average. Construction permits are way up - from \$48.7 million in 2004, to \$50.6 million in 2005, to over \$123 million in 2006. In the past five years, over 1,000 new companies have been incorporated in Fort St. John, as young families, experienced professionals, skilled trades-people and many others move here from across the country.

OIL AND GAS

POLICY ACTIONS

BE AMONG THE MOST COMPETITIVE OIL AND GAS JURISDICTIONS IN NORTH AMERICA

- **Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.**
- **Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.**
- **Encourage the development of conventional and unconventional resources.**
- **Support the growth of British Columbia's oil and gas service sector.**
- **Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.**
- **Encourage the development of new technologies.**
- **Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.**

Technology Transfer Incentive Program

A new Oil and Gas Technology Transfer Incentive Program will be considered to encourage the research, development and use of innovative technologies to increase recoveries from existing reserves and encourage responsible development of new oil and gas reserves. The program could recover program costs over time through increased royalties generated by expanded development and production of British Columbia's petroleum resources.

Scientific Research and Experimental Development

The BC Energy Plan supports the British Columbia Scientific Research and Experimental Development Program, which provides financial support for research and development leading to new or improved products and processes. Through credits or refunds, the expanded program could cover project costs directly related to commercially applicable research, and development or demonstration of new or improved technologies conducted in British Columbia that facilitate expanded oil and gas production.

Research and Development

The BC Energy Plan calls for using new or existing research and development programs for the oil and gas sector. Government will develop a program targeting areas in which British Columbia has an advantage such as well completion technology and hydrogeology.

A program to encourage oil and gas innovation and research in British Columbia's post-secondary institutions will be explored. These opportunities will be explored in partnership with the Petroleum Technology Alliance Canada and as part of the April 2006 Memorandum of Understanding between British Columbia and Alberta on Energy Research, Technology Development and Innovation.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator, a site which provides innovators with space to build prototypes and carry out testing as well as providing business infrastructure and assistance accessing additional support will be established, allowing entrepreneurs to develop and test new innovations and commercialize new, innovative technologies and processes.

Nechako Initiative

The BC Energy Plan calls for government to partner with industry, the federal government, and Geoscience BC to undertake comprehensive research in the Nechako Basin and establish new data of the resource potential. It will include active engagement of communities and the development and implementation of a comprehensive pre-tenure engagement initiative for First Nations in the region. Specific tenures and royalties will be explored to encourage investment, as well as a comprehensive Environmental Information Program to identify baseline information needs in the area through consultations with government, industry, communities and First Nations.

By increasing our oil and gas industry's competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

Value-Added Opportunities

To improve competitiveness, **The BC Energy Plan** calls for a review of value-added opportunities in British Columbia. This will include a thorough assessment of the potential for processing facilities and petroleum refineries as well as petrochemical industry opportunities. The Ministry of Energy, Mines and Petroleum Resources will conduct an analysis to identify and address barriers and explore incentives required to encourage investment in gas processing in British Columbia. A working group of industry and government will develop business cases and report to the Minister by January 2008 with recommendations on the viability of a new petroleum refinery and petrochemical industry and measures, if any, to encourage investment.

Oil and Gas Service Sector

British Columbia's oil and gas service sector can also help establish our province as one of the most competitive jurisdictions in North America. The service sector has grown over the past four years and with increased activity, additional summer drilling, and the security of supply, opportunities for local companies will continue. Government can help maximize the benefits derived from the service sector by:

- Promoting British Columbia's service sector to the oil and gas industry through participation at trade shows and providing information to the business community.
- Identifying areas where British Columbian companies can play a larger role, expand into other provinces, and through procurement strategies.

The government also supports the Oil and Gas Centre of Excellence at the Fort St. John Northern Lights College campus, which will provide oil and gas, related vocational, trades, career and technical programs.

Improving Oil and Gas Tenures

Government will work to improve oil and gas tenure issuance policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval by the end of 2007. This will provide clear parameters for industry regarding areas where special or enhanced management practices are required. These measures will strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into the oil and gas development process.

Create Opportunities for Communities and First Nations

Benefits for British Columbians from the Oil and Gas Sector

The oil and gas sector offers enormous benefits to all British Columbians through enhanced energy security, tens of thousands of good, well-paying jobs and tax revenues used to help fund our hospitals and schools. However, the day-to-day impact of the sector has largely been felt on communities and First Nations in British Columbia's northeast. Community organizations, First Nations, and landowners have communicated a desire for greater input into the pace and scope of oil and gas development in British Columbia.

OIL AND GAS

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator will be established, allowing entrepreneurs to develop and test new innovations.

POLICY ACTIONS

WORKING WITH COMMUNITIES AND FIRST NATIONS

- **Provide information about local oil and gas activities to local governments, First Nations, education and health service providers to inform and support the development of necessary social infrastructure.**
- **Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.**
- **Support First Nations in providing cross-cultural training to agencies and industry.**
- **Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.**
- **Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.**

Through **The BC Energy Plan**, government intends to develop stronger relationships with those affected by oil and gas development, including communities and First Nations. The aim is to work cooperatively to maximize benefits and minimize impacts. The plan supports improved working relationships among industry, local communities and landowners by increased and improved communication to clarify and simplify processes, enhancing dispute resolution methods, and offering more support and information.

The government will also continue to improve communications with local governments and agencies. Specifically, **The BC Energy Plan** calls for efforts to provide information about increased local oil and gas activities to local governments, education and health service providers to improve their ability to make timely decisions on infrastructure, such as schools, housing, and health and recreational facilities. By providing local communities and service providers with regular reports of trends and industry activities, they can more effectively plan for growth in required services and infrastructure.

Building Better Relationships with Landowners

The BC Energy Plan: A Vision for Clean Energy Leadership also supports improved working relationships between industry, local communities and landowners and First Nations. Landowners will be notified in a more timely way of sales of oil and gas rights on private land. Plain language information materials, including standardized lease agreements will be made available to help landowners deal with subsurface tenures and activity. There will be a review of the dispute resolution process between landowners and industry by the end of 2007. The existing setback requirements, the allowed distance of a well site from a residence, school or other public place, will also be examined. These measures seek to strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into oil and gas development.

Working in Partnership with First Nations and Communities

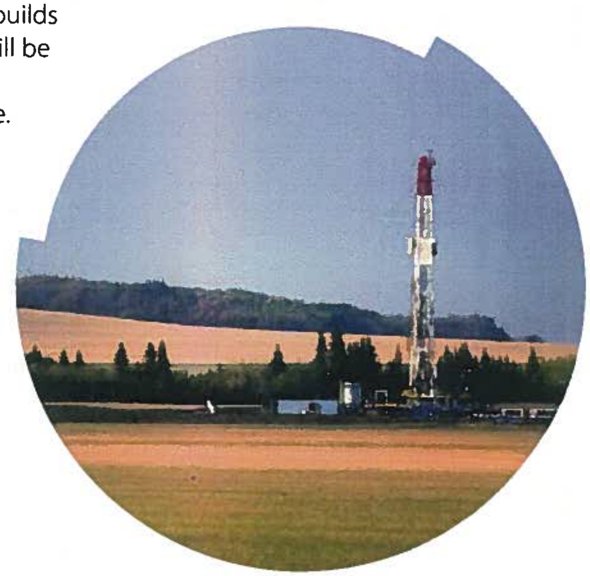
Government will work with First Nations communities to identify opportunities to benefit from oil and gas development. By developing a greater ability to participate in and benefit from oil and gas development, First Nations can play a much more active role in the industry. **The BC Energy Plan** also supports increasing First Nations role in the development of cross-cultural training initiatives for agencies and industry.

Conclusion

The BC Energy Plan: A Vision for Clean Energy Leadership sets the standard for proactively addressing the opportunities and challenges that lie ahead in meeting the energy needs for all the citizens of the province, now and in the future. Appendix A provides a detailed listing of the policy actions of the plan.

The BC Energy Plan will attract new investments, help develop and commercialize new technology, build partnerships with First Nations, and ensures a strong environmental focus.

British Columbia has a proud history of innovation that has resulted in 90 per cent of our power generation coming from clean sources. This plan builds on that foundation and ensures B.C. will be at the forefront of environmental and economic leadership for years to come.



APPENDIX A The BC Energy Plan: Summary of Policy Actions

ENERGY CONSERVATION AND EFFICIENCY

1. Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
2. Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
3. Encourage utilities to pursue cost effective and competitive demand side management opportunities.
4. Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.
5. Implement Energy Efficiency Standards for Buildings by 2010.
6. Undertake a pilot project for energy performance labeling of homes and buildings in coordination with local and federal governments, First Nations, and industry associations.
7. New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
8. Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.
9. Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.

ELECTRICITY

10. Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
11. Establish a standing offer for clean electricity projects up to 10 megawatts.
12. The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.
13. Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.
14. Ensure that the province remains consistent with North American transmission reliability standards.
15. Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.
16. Establish the existing heritage contract in perpetuity.
17. Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.
18. All new electricity generation projects will have zero net greenhouse gas emissions.
19. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
20. Require zero greenhouse gas emissions from any coal thermal electricity facilities.
21. Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
22. Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
23. No nuclear power.
24. Review BC Utilities Commissions' role in considering social and environmental costs and benefits.
25. Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.
26. Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.
27. Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
28. Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.

ALTERNATIVE ENERGY

29. Establish the **Innovative Clean Energy Fund** to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.
30. Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
31. Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.
32. Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
33. Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
34. Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
35. Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

OIL AND GAS

36. Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.
37. Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.
38. Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
39. Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.
40. Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.
41. Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.
42. Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.
43. Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.
44. Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.
45. Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.
46. Encourage the development of conventional and unconventional resources.
47. Support the growth of British Columbia's oil and gas service sector.
48. Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.
49. Encourage the development of new technologies.
50. Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.
51. Provide information about local oil and gas activities to local governments, education and health service providers to inform and support the development of necessary social infrastructure.
52. Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.
53. Support First Nations in providing cross-cultural training to agencies and industry.
54. Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.
55. Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.

Energy in Action

POWERSMART
BC Hydro offers a variety of incentives to adopt energy saving technologies. Incentives such as rebates on efficient lighting or windows encourages British Columbians to improve the energy efficiency of their homes and businesses.

PROVINCIAL SALES TAX EXEMPTIONS
Tax breaks are offered for a wide variety of energy efficient items, making it easier to conserve energy. Tax concessions are in place for alternative fuel and hybrid vehicles as well as some alternative fuels. Bicycles and some bicycle parts are exempt from provincial sales tax, as are a variety of materials, such as Energy Star® qualified windows, that can make homes more energy efficient.

NET METERING
The Net Metering program offered by BC Hydro for customers with small generating facilities, allows customers to lower their environmental impact and take responsibility for their own power production. The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced. Net Metering helps to move the province towards electricity self sufficiency and expands clean electricity generation.

POWERING THE ECONOMY
The Oil and Gas sector invested $4.6 billion in B.C. in 2005 and contributed more to the provincial treasury than any other resource in 2005/06. In 2006 1,416 oil and gas wells were drilled in the province and between 2002 and 2005, summer drilling increased 242 per cent.

FRIDGE BUY-BACK PROGRAM
This program offers customers $30 in cash and no-cost pickup and disposal of an old, inefficient second fridge. If all second operating fridges in B.C. were recycled, we would save enough energy to power all the homes in the city of Chilliwack for an entire year.

LIGHTING REBATES
This program offers instant rebate coupons for the retail purchase of Energy Star® light fixtures and Energy Star® CFLs (Compact Fluorescent Lights).

WINDOWS REBATE
The Windows Rebate Program offers rebates for the installation of Energy Star® windows in new, renovated or upgraded single-family homes, duplexes, townhouses or apartments.

PRODUCT INCENTIVE PROGRAM
The Product Incentive Program provides financial incentives to organizations which replace inefficient products with energy efficient technologies or add on products to existing systems to make them more efficient.

HIGH-PERFORMANCE BUILDING PROGRAM FOR LARGE COMMERCIAL BUILDINGS
Financial incentives, resources, and technical assistance are available to help qualified projects identify energy saving strategies early in the design process; evaluate alternative design options and make a business case for the high-performance design; and, offset the incremental costs, if any, of the energy-efficient measures in the high-performance design.

HIGH-PERFORMANCE BUILDING PROGRAM FOR SMALL TO MEDIUM COMMERCIAL BUILDINGS
Incentives and tools are offered to help owners and their design teams create and install more effective and energy-efficient lighting in new commercial development projects.

NEW HOME PROGRAM
Builders and developers are encouraged to build energy efficient homes by offering financial incentives and Power Smart branding for homes that achieve energy efficient ratings.

ANALYZE MY HOME
BC Hydro offers an online tool that provides a free, personalized breakdown of a customer's home energy use and recommendations on where improvements can be made to lower consumption.

CONSERVATION RESEARCH INITIATIVE
A 12-month study in six communities that examines how adjusting the price of electricity at different times of day influences energy use by residential customers, and how individual British Columbians can make a difference in conserving power in their homes and help meet the growing demand for electricity in B.C.

THE GREEN BUILDINGS PROGRAM
Provides tools and resources to support school districts, universities, colleges, and health authorities to improve the energy efficiency of their buildings across the province.

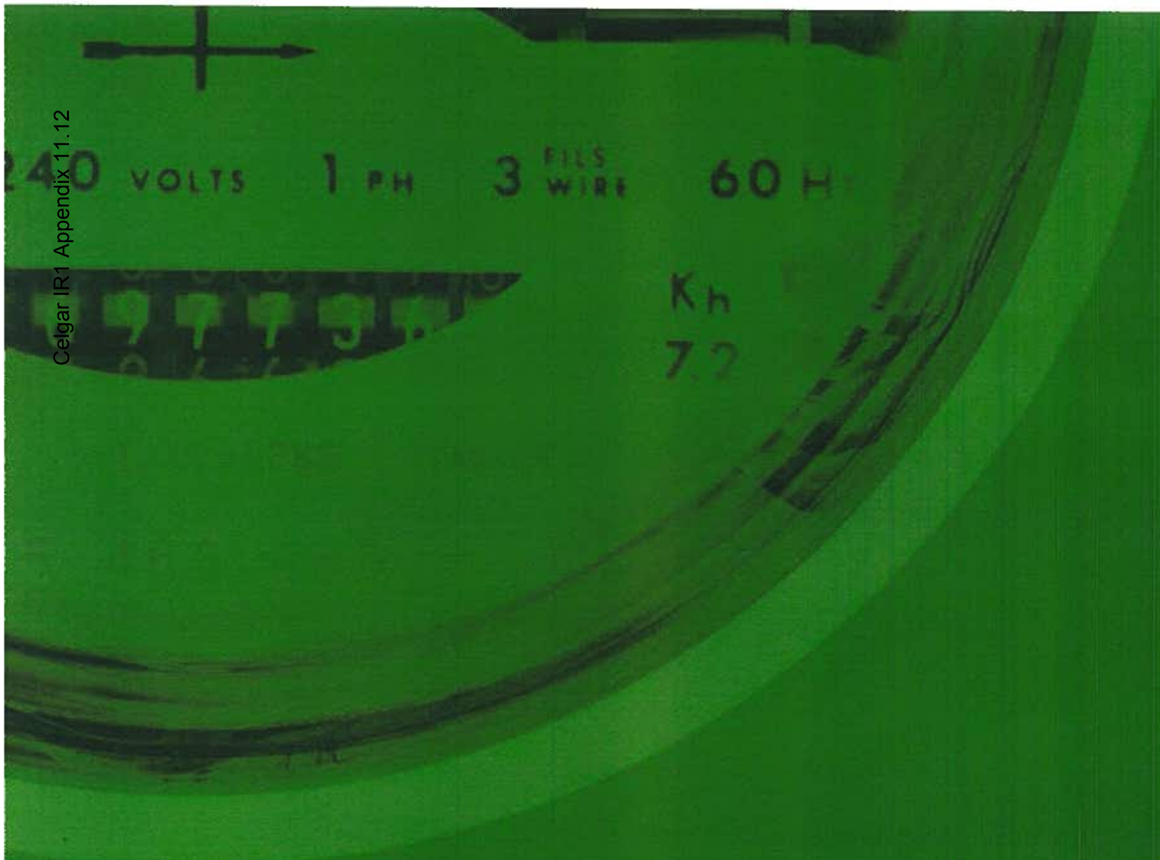
ATTRACTING WORKERS
The Ministry of Energy, Mines and Petroleum Resources hosts job fairs across B.C. to attract workers to the highly lucrative oil and gas sector. Job fairs were held in 14 communities in 2005 and 16 communities in 2006 attracting thousands of people and resulting in hundreds of job offers. Centre of Excellence Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

CENTRE OF EXCELLENCE
Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

100,000 SOLAR ROOFS FOR B.C.
The Ministers of Environment, and Energy, Mines and Petroleum Resources are sponsoring the development of a plan that will see the aggressive adoption of solar technology in B.C. The goal of the project is to see the installation of solar roofs and walls for hot water heating and photovoltaic electricity generation on 100,000 buildings around B.C.

PARTNERING FOR SUCCESS
Since 2003, the Province of B.C. has partnered in the construction of $158 million in new oil and gas road and pipeline infrastructure. The Sierra Yoyo Desan Road public private partnership improved the road allowing year round drilling activity in the Greater Sierra natural gas play. The project was recognized with the Gold Award for Innovation and Excellence from the Canadian Council for Public Private Partnerships in 2004.

ENERGY EFFICIENT BUILDINGS: A PLAN FOR BC
This strategy will lower energy costs for new and existing buildings by $127 million in 2010 and $474 million in 2020, and reduce greenhouse gas emissions by 2.3 million tonnes in 2020. The Province is implementing ten policy and market measures in partnership with the building industry, energy consumer groups, utilities, non-governmental organizations, and the federal government.



For more information on
The BC Energy Plan:
A Vision for Clean Energy Leadership, contact:

Ministry of Energy, Mines and Petroleum Resources
1810 Blanshard Street
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BRITISH COLUMBIA
The Best Place on Earth
Ministry of
Energy, Mines and
Petroleum Resources

1. Waneta Expansion Agreement

Please provide the contemplated changes to the existing Canal Plant Agreement to accommodate the Waneta Expansion and FortisBC capacity purchase.

Response:

There are a number of items that must be dealt with to allow including the Waneta Expansion into the Canal Plant Agreement. Examples would be adjustments to the Joint System minimum entitlement usage requirements and revised outage rate tables for the existing Waneta Plant plus new outage tables for WAX.

Discussions continue with BC Hydro and other entitlement parties to conclude these changes and therefore the Company is unable to provide full details at this time. However, there should not be any negative impacts on the Company's existing facilities.

2. Does FortisBC currently hold a secure water license for the proposed Similkameen Project?

Response:

FortisBC does not hold a secure water licence for the proposed Similkameen project. FortisBC has an active water licence application for the Similkameen project with priority for both power and storage.

3. Exhibit B-2, panel 16, Market Assessment

Please clarify whether the "BC New Resources" cost line is only for facilities built today, or built in each future year to 2040 relative to the wholesale power rate.

Response:

The BC New Resources Market Curve for Energy (which is also shown in Figure 3.3.2-A in the Long-Term Resource Plan and Figure 1.1-A in Appendix B - Midgard Energy and Capacity Market Assessment) represents the $/MWh cost of new capacity facilities built today and in the future. The cost is determined at the time the facility is built.

4. Exhibit B-2, panel 52, Physical Structure

Please detail the work required and the expected cost of each major part, to resurface the Upper Bonnington Overflow Concrete.

Response:

This work is not scheduled for construction until 2026; as such the Company has not completed a detailed scope for this work. However, the preliminary scope of work allows for the work to be divided into four phases. Each phase will include one quarter section of the overflow spillway to allow for water passage over the other three quarters of the spillway. Each phase will likely include the components listed below:

1. Engineering ($2 million total)
   a. Detailed engineering for the required repair work.
   b. Environmental assessment.
   c. Construction support engineering.
2. Construction ($28 million total)
   a. Supply and Install Water Diversion / Coffer Structure.
   b. Supply and Install Access.

c. Remove Deteriorated Surface Concrete.

d. Drill and Grout Reinforcing Dowels.

e. Supply and Install Reinforcing Steel.

f. Supply and Install Formwork.

g. Place and Finish Concrete.

h. Strip and Remove Formwork.

i. Dry Finish Concrete.

j. Remove Access.

k. Remove Water Diversion / Coffer Structure.

5. Please provide a copy of the Waneta Expansion Capacity Purchase Agreement, specifically showing the mechanics of the capacity purchases and the replacement procedures for the energy used. If the prices must be redacted, so be it.

Response:

The Waneta Expansion Capacity Purchase Agreement is a confidential agreement as it contains commercially sensitive information. At this point in time, release of the agreement and the related confidential justification of that agreement could jeopardize the Company's ability to maximize the benefit to customers associated with the re-sale of excess capacity. In addition, the Waneta Capacity Purchase Agreement does not cause costs during this test period. The Company anticipates being able to provide much of this information prior to the Agreement having financial impacts on future Revenue Requirement Applications.

6. With the major peaking power capacity secured in the West Kootenay, is FortisBC reviewing the Transmission system to the Okanagan before future Transmission projects are undertaken in the Kootenay-Okanagan corridor?

Response:

Currently, even in the long term, no transmission upgrades have been identified to support the transfer of additional power from the West Kootenay to the Okanagan area. However, as customer load continues to grow FortisBC will periodically study the system needs and present the results for review in future Capital Plan filings.