Fasken Martineau DuMoulin LLP *
Barristers and Solicitors
Patent and Trade-mark Agents

2900 - 550 Burrard Street
Vancouver, British Columbia, Canada V6C 0A3

604 631 3131 Telephone
604 631 3232 Facsimile

www.fasken.com

Matthew Ghikas
Direct 604 631 3191
Facsimile 604 632 3191
mghikas@fasken.com

December 16, 2011
File No.: 240148.00675/14797

BY ELECTRONIC FILING

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

**Attention: Erica M. Hamilton,
Commission Secretary**

Dear Sirs/Mesdames:

Re: An Application by FortisBC Energy Utilities [Comprising FortisBC Energy Inc., FortisBC Energy Inc., Fort Nelson Service Area, FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc.] 2012 and 2013 Revenue Requirements and Natural Gas Rates

We enclose for filing in the above proceeding, the electronic version of FortisBC Energy Utilities' Submission regarding the amendments to the Demand-Side Measures Regulation.

Twelve hard copies of the Submission will follow by courier.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by Matthew Ghikas]

Matthew Ghikas

MTG/ccm
Encl.

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE *UTILITIES COMMISSION ACT*, R.S.B.C. 1996, CHAPTER 473

AND

An Application by FortisBC Energy Utilities

[COMPRISING FORTISBC ENERGY INC., FORTISBC ENERGY INC., FORT NELSON SERVICE AREA, FORTISBC ENERGY (WHISTLER) INC., AND FORTISBC ENERGY (VANCOUVER ISLAND) INC.]

2012 AND 2013 REVENUE REQUIREMENTS AND NATURAL GAS RATES

SUBMISSION OF FORTISBC ENERGY UTILITIES REGARDING IMPACTS OF AMENDMENTS TO THE DSM REGULATION

December 16, 2011

SUBMISSION OF FORTISBC ENERGY UTILITIES REGARDING IMPACTS OF AMENDMENTS TO THE DSM REGULATION

1. This is the FEU's submission regarding the December 9, 2011 amendments to the Demand-Side Measures (DSM) Regulation, B.C. Reg. 326/2008 (the "Amendments").[1] The Amendments are attached as **Appendix 1** to this submission. As discussed below, the impact of the Amendments is that the FEU are withdrawing their proposed Societal Cost Test ("SCT"). The FEU are not making any other changes to the proposed Energy Efficiency and Conservation ("EEC") expenditures as a result of the Amendments.

2. In this submission, the FEU will:

(a) Provide a brief overview of the relevant changes to the cost-effectiveness regime required by the Amendments to the DSM Regulation.

(b) Discuss how the modified total resource cost test ("MTRC") mandated by the Amendments supersedes the FEU's request for the use of a SCT.

(c) Provide the cost-effectiveness results for the FEU's portfolio of existing programs and new program areas.

3. As discussed below, the FEU's proposed portfolio of EEC expenditures, including the new program areas, are cost-effective under the new cost-effectiveness regime mandated by the amended DSM Regulation.

A. OVERVIEW OF AMENDMENTS

4. One of the factors that the Commission is required to consider when determining whether DSM expenditures are in the public interest is their cost-effectiveness pursuant to the DSM Regulation.[2] The Amendments to the DSM Regulation make a number of changes to the way in which the Commission must consider the cost-effectiveness of DSM expenditures.

[1] Ministerial Order No. M 335.

[2] *Utilities Commission Act*, section 44.2(5)(d).

5. In the FEU's submission, the changes that are relevant to this proceeding are as follows:

(a) According to section 4(1.1) of the amended DSM Regulation, the Commission must use the MTRC as set out in that section. The MTRC consists of the following two components:

(i) According to section 4(1.1)(a), the use of an avoided cost of natural gas representing BC Hydro's avoided long-run marginal cost ("LRMC") of acquiring electricity from clean or renewable resources, with an adjustment factor of 0.5, referred to below as the "LRMC proxy".[3]

(A) The Amendments do not prescribe what the LRMC is. BC Hydro's avoided LRMC of acquiring electricity from clean or renewable resources is best derived from BC Hydro's Clean Power Call Request for Proposals Report on the RFP Process, August 3, 2010 (attached as **Appendix 2**). The pricing information that underpins the LRMC proxy is in Table 3-5 on page 12. The report is stated in 2009$, so to arrive at the LRMC proxy in today's dollars, the LRMC needs to be escalated for two years. The resulting LRMC proxy of acquiring electricity from clean or renewable resources is $18.32/GJ for 2012 and $18.69/GJ for 2013.

(B) Pursuant to section 4(1.3), this avoided cost of natural gas is not used for programs that encourage switching oil or propane to natural gas, such as the FEU's "Switch N' Shrink" program.

(ii) According to sections 3(a) and 4(1.1)(c), the use of a 15% deemed adder for non-energy benefits for DSM, other than for low-income measures which continue to employ a 30% deemed adder.

[3] See **Appendix 2**, page 19.

(A) Under section 4(1.1)(c), while the total deemed adder must be 15%, the Commission may conclude that the non-energy benefits of particular programs are greater (or less than) 15%, thus leaving open the possibility for the attribution of non-energy benefits greater than 15%. At this time, the FEU have not gathered any evidence demonstrating any particular percentage of non-energy benefits for any particular DSM. A 15% deemed adder must therefore be applied generally.

(b) Under section 4(1.5), there is a 33% cap on program expenditures within a portfolio that *pass the MTRC* but otherwise are not cost-effective. In the words of the regulation, it applies to a demand-side measures that is "cost effective when applying subsection (1.1)" but "is not cost-effective without applying subsection (1.1). For the purpose of applying this 33% cap, the FEU assume that in the absence of the MTRC, the Commission would consider a demand-side measure to be not cost-effective if it failed the TRC. The cap therefore only applies to programs that pass the MTRC, but fails the TRC. As the cap only applies to programs that pass the MTRC, it does not apply to expenditures to which the MTRC cannot be applied, such as the FEU's Conservation, Education and Outreach program area, the Energy Efficiency Partners program and portfolio-wide costs. Further, section 4(1.5) states that it is subject to section 4(4) and (5), so the cap does not apply to "specified demand-side measures"[4] or "public awareness programs." As discussed below, the FEU's proposed portfolio of EEC activity for 2012 and 2013 does not exceed the cap.

(c) Under section 4(1.8), the Commission has the discretion to reject certain demand-side measures if they fail the Utility Cost Test ("UCT"). To be clear, the Commission is not required to reject programs that fail the UCT; section 4(1.8) simply gives the Commission the discretion to do so. The corollary of this

---

[4] "Specified demand-side measures" is defined in section 1 of the DSM Regulation and includes: education programs for students, funding for energy efficiency training, a community engagement program and a technology innovation program as those terms are defined in the DSM Regulation.

provision is that the Commission does not have discretion to reject programs that fail the UCT that are exempted in section 4(1.8), including specified demand-side measures, public awareness programs and low-income programs.

(d) The definition of “technology innovation program”, which is a “specified demand-side measure”, is amended so that paragraph (a) of the definition reads: “technology innovation program” means a program (a) to develop use or support the increased use of 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”.[5] This change does not impact the FEU’s technology innovation programs in the proposed 2012/2013 EEC portfolio.

6. The Amendments do not change the fact that the Commission may determine cost-effectiveness on a portfolio basis (s.4(1)) and may not reject a DSM expenditure for failing the ratepayer impact measure (RIM) test (s.4(6)).

B. THE MTRC TEST SUPERSEDES THE PROPOSED SCT

7. In the Application,[6] the FEU proposed that the Commission adopt a Societal Cost Test, including a social discount rate, an avoided cost of gas equal to the cost of biomethane and a 30% deemed adder for non-energy benefits. As outlined above, however, the Amendments require the Commission to use the MTRC set out in section 4(1.1) of the amended DSM Regulation. The FEU therefore withdraw their proposed Societal Cost Test. *Part Eleven, Section C: The Attributes of the Proposed SCT* of the FEU’s December 2 Submission can therefore be disregarded.

8. The FEU are not withdrawing their request that spillover effects be considered in cost-effectiveness calculations.

[5] Emphasis added.

[6] Exhibit B-1, Appendix K-1.

C. THE FEU'S PROGRAMS ARE COST-EFFECTIVE

9. The FEU's portfolio for existing program areas and new program areas are cost-effective under the cost-effectiveness regime mandated by the Amendments to the DSM Regulation.

10. Attached as **Appendix 3** are the MTRC test results for the FEU's existing program areas. The FEU's existing program areas have a portfolio-level TRC result of 1.27 and an MTRC result of 2.78. The higher MTRC results reflect the higher avoided cost of natural gas of $18.32/GJ for 2012 and $18.69/GJ for 2013 and the 15% deemed adder required by section 4(1.1) of the amended DSM Regulation. The only individual program in the existing program areas that fails the MTRC is the Energy Conservation Assistance Program ("ECAP"). As the overall portfolio is cost-effective, however, the FEU submit that this program expenditure should be accepted. The FEU submit that it would not be in the public interest to reject low-income programs based on individual cost-effectiveness results. Please refer to paragraphs 444 to 449 of the FEU's December 2, 2011 Submission.

11. As shown in Table 1 below, the FEU's proposed new program areas (Furnace Scrap-it, Solar Thermal and Thermal Energy for Schools)[7] can be incorporated in the portfolio of existing program areas rendering a cost-effective portfolio with a MTRC result of 1.9. Cost-effectiveness results for each of the new program areas are shown in Table 2. The Furnace Scrap-it program has a MTRC result marginally lower than 1.0. The Companies are confident that the Furnace Scrap-it program can be managed such that the MTRC result is 1.0, by reducing some of the non-incentive costs such as marketing and promotion of the program at the time the final program design is undertaken. As innovative technology programs, the Solar Thermal and Thermal Energy Schools programs are specified demand-side measures and must be evaluated on a portfolio basis.[8] As shown in Table 1, these programs can be incorporated into a portfolio with an MTRC of 1.9.

[7] See the FEU's December 2 Submission, *Part Eleven, Section G: New Program Areas*.

[8] Section 4(4) of the DSM Regulation.

Table 1: Cost-Effectiveness of EEC Portfolio with New Program Areas

	Benefit/Cost Ratios					
	TRC	MTRC	UCT	PCT	RIM	SCT
Previously approved program areas and all New Initiative programs	0.70	1.90	2.34	1.52	0.68	1.95
Previously approved program areas with Furnace Scrap-it only	1.04	2.20	1.72	1.99	0.57	2.43
Previously approved program areas with Furnace Scrap-it and Solar Thermal	1.00	2.10	1.61	1.97	0.56	2.34
Previously approved program areas with Furnace Scrap-it and Thermal for Schools	0.72	1.95	2.49	1.52	0.70	2.00

Table 2: Cost-Effectiveness Results for Programs that fail the TRC but pass the MTRC, or fail the UCT, including New Program Areas

Program Name	Program Area	Program budget ($000's)		Percentage of overall budget		Benefit/Cost Ratios					
		2012	2013	2012	2013	TRC	MTRC	UCT	PCT	RIM	SCT
ENERGY STAR® Domestic Hot Water "DHW" Technologies	Residential	1,786	1,786	2.77%	2.77%	0.50	1.13	1.23	1.06	0.49	1.27
ENERGY STAR® Washers and Other Measures for DHW Conservation	Residential	525	525	0.81%	0.81%	0.94	2.03	4.44	1.49	0.68	2.25
Customer Engagement Tool for Conservation Behaviours*	Residential	500	1,050	0.78%	1.63%	0.69	1.67	0.69		0.37	1.58
New Construction – EGH 80 & Beyond and EE Appliances	Residential	945	945	1.46%	1.46%	0.45	1.01	1.89	0.92	0.52	1.20
Energy Conservation Assistance Program (ECAP)	Low Income	4,450	4,450	n/a	n/a	0.38	0.75	0.28	1.61	0.21	0.71
Continuous Optimization Program	Commercial	2,062	2,812	3.20%	4.36%	0.98	2.24	3.17	2.25	0.46	2.32
Catalytic Radiant Burner Technology	Innovative Technology	53	313	n/a	n/a	0.79	1.78	1.36	1.71	0.52	1.89
SUB-TOTAL PREVIOUSLY APPROVED PROGRAM AREAS		**5,818**	**7,118**	**9.02%**	**11.04%**						
Furnace Scrap-It Program	New Initiatives	10,000	10,000	15.50%	15.50%	0.59	0.95	0.82	0.70	0.47	1.25
Solar Thermal	New Initiatives	4,000	4,000	n/a	n/a	0.19	0.42	0.21	0.95	0.19	0.51
Thermal Energy for Schools	New Initiatives	11,000	11,000	n/a	n/a	0.16	1.52	5.75	0.62	0.99	1.24
SUB-TOTAL NEW INITIATIVES BASED ON TOTAL FUNDING ENVELOPE		25,000	25,000	15.50%	15.50%						
TOTAL		**30,818**	**32,118**	**24.52%**	**26.54%**						

12. The Amendments place a 33% cap on program expenditures that pass the MTRC, but are otherwise not cost-effective.[9] Table 2 above shows the programs that do not pass the TRC, but that pass the MTRC. It can be seen that programs that fall under the application of the MTRC in order to be considered cost-effective comprise 24.52% for 2012 and 26.54% for 2013 of the requested funding envelope of $64.5 million, well below the 33% cap.

(a) As explained above, “specified demand-side measures” and “public awareness programs” as defined in the DSM Regulation are not included in the cap. The funding for the Radiant Catalytic Burner program, the Solar Thermal program and the Thermal Energy for Schools program were therefore excluded from the calculation of the cap levels as these programs are technology innovation programs.

(b) Further, programs to which the MTRC cannot be applied or which do not pass the MTRC are also excluded from the cap. The FEU included the Furnace Scrap-it program within the cap since it has an MTRC of .95 which is very close to 1.0. The ECAP, with an MTRC of 0.75, was not included in the cap because it clearly does not pass the MTRC. Even if the ECAP were included in the calculation, the portfolio would not exceed the cap in 2012 (at 31.42%) and would be just at the cap level for 2013 (at 33.44%).

13. Section 4(8) of the amended DSM Regulation gives the Commission the discretion to use the UCT to evaluate the cost-effectiveness of programs, except for specified demand-side measures, public awareness programs, low-income programs as referred to in section 3(a) and programs that are cost effective without applying section 4(1.1) but after applying 4(1.4). The FEU have four programs that fail the UCT. These programs are (a) ECAP (in the Low Income program area),[10] (b) the Customer Engagement Tool for Conservation

---

[9] As noted above, the FEU assume that in the absence of the MTRC, and without evidence to the contrary, the Commission would apply the TRC test.

[10] Appendix 4, Exhibit 5. Also see Exhibit B-25, Appendix 1, 2012-2013 EEC Plan, p. 23.

Behaviours (in the Residential program area),[11] (c) the Furnace Scrap-It program,[12] and (d) the Solar Thermal program.[13] Each of these is addressed below.

(a) ECAP is aimed at low-income residents as described in section 3(a) of the DSM Regulation and is therefore exempt from the UCT pursuant to section 4(1.8) of the amended DSM Regulation. The Commission therefore may not reject these program expenditures based on UCT results.

(b) The Customer Engagement Tool for Conservation Behaviours program has a MTRC result of 1.67. It has been successfully deployed in other jurisdictions[14] and has been the subject of third-party studies verifying energy savings, which are projected to increase in future years, and should therefore improve the UCT result.[15] Further, the Customer Engagement Tool for Conservation Behaviours program can be incorporated into an overall cost-effective portfolio under the MTRC.[16] The FEU therefore submit that the Commission should accept these program expenditures.

(c) The Furnace Scrap-It program has an MTRC result of 0.95 and a UCT result of 0.82. As indicated above, the Companies are confident that this program can be managed such that the MTRC result is 1.0, by reducing some of the non-incentive costs such as marketing and promotion of the program at the time the final program design is undertaken. While the UCT result for this program is marginal, the Companies view is that this program has significant merit and should proceed. Please see *Part Eleven, Section G: Furnace Scrap-it Program* of the FEU's December 2, 2011 Submission.

(d) The Solar Thermal program has an MTRC result of 0.42 and a UCT result of 0.21; however, as a technology innovation program, the Solar Thermal program is

[11] Appendix 4, Exhibit 3.
[12] See Table 2 above.
[13] See Table 2 above.
[14] Exhibit B-67, BCUC IR 3.12.6 and BCUC IR 3.12.6.1. Smith: T9, p. 1400, l. 24 to p. 1401, l. 6.
[15] Exhibit B-67, BCUC IR 3.12.1, 3.12.4 and 3.12.6.1, including attachment 6.1; Exhibit B-76.
[16] Table 1 above. Also see Appendix 4, Exhibit 2.

a specified demand-side measure. The Commission therefore may not reject these program expenditures based on UCT results pursuant to section 4(1.8) of the amended DSM Regulation.

14. In summary, the evidence shows that the FEU's proposed DSM programs, both for existing and new program areas, are cost-effective under the cost-effectiveness regime mandated by the amended DSM Regulation.

E. CONCLUSION

15. One of the factors that the Commission is required to consider when determining whether DSM expenditures are in the public interest is their cost-effectiveness pursuant to the DSM Regulation.[17] The Amendments to the DSM Regulation require the Commission to use a specific cost-effectiveness regime, including the two-part MTRC test explained above. The FEU submit that its proposed EEC expenditures are cost effective under the new cost-effectiveness regime. Overall, the FEU submits that the proposed EEC expenditures are in the public interest and should be accepted.

[17] *Utilities Commission Act*, section 44.2(5)(d).

APPENDICES

1. Ministerial Order No. M 335, amending the Demand-Side Measures Regulation, B.C. Reg. 326/2008.

2. BC Hydro, Clean Power Call Request for Proposals Report on the RFP Process, August 3, 2010

3. MTRC test results for the FEU's existing program areas

Appendix 1

MINISTERIAL ORDER NO. 355 – DEMAND-SIDE REGULATION AMENDMENT

PROVINCE OF BRITISH COLUMBIA

REGULATION OF THE MINISTER OF ENERGY AND MINES AND MINISTER RESPONSIBLE FOR HOUSING

Utilities Commission Act

Ministerial Order No. M 335

I, Rich Coleman, Minister of Energy and Mines and Minster Responsible for Housing, order that the Demand-Side Measures Regulation, B.C. Reg. 326/2008, is amended as set out in the attached schedule.

DEPOSITED

DEC 8 2011

B.C. REG. 228/2011

DEC - 8 2011

Date

Minister of Energy and Mines and Minister Responsible for Housing

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 125.1 (4) (c)

Other: M271/2008

November 10, 2011 R/656/2011/27

SCHEDULE

1 *Section 1 of the Demand-Side Measures Regulation, B.C. Reg. 326/2008, is amended*

(a) *by adding the following definition:*

"clean or renewable resource" has the same meaning as in the *Clean Energy Act;*

(b) *by repealing the definition of* "energy device",

(c) *by repealing the definition of* "energy efficiency training" *and substituting the following:*

"energy efficiency training" means training for persons who

(a) manufacture, sell or install energy-efficient products or products that conserve energy,

(b) design, construct or act as a real estate broker with respect to energy-efficient buildings,

(c) manage energy systems,

(d) conduct energy efficiency and conservation audits,

(e) on behalf of an organization, manage or advise with respect to the conservation or efficient use of energy in the organization's facilities, or

(f) in an organization, educate other persons about the benefits of energy efficiency and conservation; ,

(d) *by repealing paragraphs (a) and (d) in the definition of* "regulated item" *and substituting the following:*

(a) a product or system that uses energy or controls or affects the use of energy,

(e) a building site design or building site selection plan, or

(f) a community design; ,

(e) *in the definition of* "specified demand-side measure" *by adding the following paragraph:*

(e) financial or other resources provided

(i) to a standards-making body to support the development of standards respecting energy conservation or the efficient use of energy, or

(ii) to a government or regulatory body to support the development of or compliance with a specified standard or a measure respecting energy conservation or the efficient use of energy in the Province; ,

(f) *by adding the following definition:*

"specified proposal" means

(a) a proposal respecting an amendment to the regulation referred to in paragraph (a) of the definition of "specified standard", if the proposal is published by the minister responsible for the *Energy Efficiency Act* and specifically refers to this regulation;

(b) a proposal respecting an amendment to the regulations referred to in paragraph (b) of the definition of "specified standard", if the proposed amendment is published in the Canada Gazette;

(c) a proposal respecting an amendment to a standard referred to in paragraph (c) of the definition of "specified standard", if the proposal is published by the government and specifically refers to this regulation;

(d) a proposal respecting

(i) a new bylaw, or

(ii) an amendment to a bylaw

referred to in paragraph (d) of the definition of "specified standard", if the proposal has been given first reading by the council of the local authority;

(e) a proposal respecting

(i) a new law, or

(ii) an amendment to a law

referred to in paragraph (e) of the definition of "specified standard", if the proposal has been published by the governing body referred to in that paragraph;,

(g) in the definition of "specified standard" *by adding the following paragraphs:*

(d) a bylaw of a local authority, if the standard promotes energy conservation or the efficient use of energy in the Province;

(e) a law passed by a governing body of a first nation, if the standard promotes energy conservation or the efficient use of energy in the Province;, *and*

(h) in paragraph (a) of the definition of "technology innovation program" *by adding* ", use or support the increased use of" *after* "to develop".

2 *Section 4 is amended*

(a) in subsection (1) by striking out "Subject to subsections (4) and (5)" *and substituting* "Subject to subsections (1.5), (4) and (5)",

(b) by adding the following subsections:

(1.1) The commission must make determinations of cost effectiveness by applying the total resource cost test as follows and in the order set out:

(a) subject to subsections (1.2) and (1.3), the avoided natural gas cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is the amount that the commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia, multiplied by 0.5;

(b) subject to subsection (1.3), the avoided electricity cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is

(i) in the case of a demand-side measure of FortisBC Inc., an amount that the commission is satisfied represents FortisBC Inc.'s long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia, and

(ii) in the case of a demand-side measure not referred to in subparagraph (i), an amount that the commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia;

(c) with respect to a demand-side measure not referred to in section 3 (a), do the following:

(i) increase the benefits of the demand-side measure by an amount that does not exceed an amount proposed by the public utility for this purpose, if the commission is satisfied that the amount represents the participant or utility non-energy benefits of the demand-side measure;

(ii) if the benefits of a demand-side measure have not been increased under subparagraph (i) or if the benefits of the expenditure portfolio of which the demand-side measure is a part has not been increased by 15% or more as a result of an increase under subparagraph (i), increase the benefit of the demand-side measure by an amount that

(A) increases by 15% the benefits of the expenditure portfolio of which the demand-side measure is a part, and

(B) is equal to the increase made under this subparagraph for all the other demand-side measures that are part of the expenditure portfolio.

(1.2) Subsection (1.1) (a) does not apply to a demand-side measure that reduces the use of natural gas but does not reduce greenhouse gas emissions associated with that use of natural gas.

(1.3) Subsection (1.1) (a) and (b) does not apply to a demand-side measure that encourages a switch from the use of oil or propane to the use of natural gas or electricity such that the switch would decrease greenhouse gas emissions in British Columbia.

(1.4) In considering a demand-side measure that, in the commission's opinion, will increase the use of a regulated item with respect to which there is either

(a) a specified standard that has not yet commenced, or

(b) a specified proposal,

the commission, after applying subsection (1.1), may increase the benefit of the demand-side measure by an amount that represents a portion of the avoided capacity and energy costs that, in the commission's opinion, will result from the commencement and application of the specified standard, amendment or new bylaw proposed by the specified proposal, assuming that the standard, amendment or new bylaw comes into force.

(1.5) Despite subsection (1.1) and subject to subsections (4) and (5), the commission must determine that a demand-side measure that is part of an expenditure portfolio and that is cost effective when applying subsection (1.1) is not cost effective if

(a) the demand-side measure is not cost-effective without applying subsection (1.1), and

(b) the total expenditures respecting

(i) the demand-side measure, and

(ii) all other demand-side measures that are part of the expenditure portfolio, that are not cost effective without applying subsection (1.1) and that are cost effective when applying subsection (1.1),

are more than

(iii) 33% of the total expenditures for the expenditure portfolio, in the case of a utility that recovers the expenditures in gas rates, or

(iv) 10% of the total expenditures for the expenditure portfolio, in the case of a utility that recovers the expenditures in electricity rates.

(1.6) For greater certainty, if the commission determines under subsection (1.5) that a demand-side measure that is part of an expenditure portfolio is not cost effective, the commission must exclude that demand-side measure from consideration when determining under that subsection whether another demand-side measure that is part of the expenditure portfolio is cost effective.

(1.7) For the purposes of subsections (1.1) (c) and (1.5), the commission, when considering the benefits or expenditures respecting a public utility's expenditure portfolio, may consider a demand-side measure of the public utility that is not included in the expenditure portfolio to be a part of the expenditure portfolio.

(1.8) Despite subsection (1.1), the commission may determine that a demand-side measure, other than

(a) a specified demand-side measure,

(b) a public awareness program,

(c) a demand-side measure referred to in section 3 (a), or

(d) a demand-side measure that is cost effective without applying subsection (1.1) but after applying subsection (1.4)

is not cost effective if the demand-side measure would not be considered cost-effective under the utility cost test.

(c) in subsection (2) (b) by adding "but after applying subsection (1.1)" *after* "without reference to this subsection", *and*

(d) by repealing subsections (3) and (7).

Appendix 2

BC HYDRO CLEAN POWER CALL REQUEST FOR PROPOSALS
REPORT ON THE RFP PROCESS - AUGUST 3, 2010

CLEAN POWER CALL REQUEST FOR PROPOSALS

Report on the RFP Process

August 3, 2010

BC hydro
FOR GENERATIONS

BRITISH COLUMBIA
The Best Place on Earth

PURPOSE OF REPORT

British Columbia Hydro and Power Authority (BC Hydro) prepared this document (the Report) to explain the rationale for awarding 25 Electricity Purchase Agreements (EPAs) with a volume of 3,266 Gigawatt hours (GWh) per year of firm energy pursuant to the Clean Power Call Request for Proposals (RFP).

A Note on Price Disclosure

BC Hydro believes in the importance of transparency. However, BC Hydro must at the same time treat as confidential any information which if disclosed could reasonably be expected to result in significant harm or prejudice to the proponent's competitive position or undue material financial loss or gain to a person. In this Report BC Hydro has provided levelized plant gate prices and levelized adjusted Firm Energy Prices (FEPs) for the awarded EPAs, as well as the final bid prices in dollars per megawatt hour ($/MWh) for the awarded EPAs. This information is provided without attribution.

CONTENTS

1. EXECUTIVE SUMMARY

To ensure that there is sufficient clean, renewable energy to meet forecast electricity demand, BC Hydro issued the Clean Power Call on June 11, 2008. The Clean Power Call was a result of comprehensive planning, design and engagement to ensure that the terms of the call resulted in the acquisition of cost-effective new supply for BC Hydro's ratepayers.

In November 2008, BC Hydro received 68 proposals from 43 proponents, representing more than 17,000 GWh per year of energy. Ultimately, BC Hydro selected 27 projects for the award of 25 EPAs (three projects were combined into a single EPA), representing 3,266 GWh per year of firm energy and 1,168 megawatts (MW) of capacity. The 27 projects included 19 run-of-river projects, six wind projects, one storage hydro project and one waste heat project.

Determining the Need for the Clean Power Call

In its 2008 Long Term Acquisition Plan (LTAP), BC Hydro identified the need for a Clean Power Call with a proposed pre-attrition target of 5,000 GWh/year of firm energy. This target was subsequently lowered but BC Hydro reserved the right to acquire up to 5,000 GWh/year if the EPAs proved to be cost-effective. As evidenced by the final level of EPA awards, BC Hydro has chosen to acquire less than the initial Clean Power Call target volume on the basis that the non-successful projects were viewed as not being cost-effective or having other eligibility or risk-related problems.

At the time of completing its evaluation of Clean Power Call proposals, BC Hydro updated its load forecasts and reassessed its energy load/resource balance. Based on existing and committed resources, BC Hydro determined that there would be a shortfall of 600 GWh in F2013, which would grow to 4,100 GWh in F2017. Notwithstanding the energy expected to be acquired from BC Hydro's current acquisition processes (the Bioenergy Phase 2 Call and the Integrated Power Offer), there is still a projected energy shortfall of 2,300 GWh/year beginning in F2017. The 3,266 GWh/year being purchased under the Clean Power Call equates to 2,286 GWh/year on a post-attrition basis (using an assumed 30% attrition factor) and will effectively fill the projected F2017 energy gap, thereby resulting in self-sufficiency by the prescribed 2016 date.

Designing the Call and Involving Stakeholders and First Nations in the Process

The Clean Power Call utilized an RFP process to allow more flexibility for negotiating price and cost-effective contract terms and conditions. This was done, in part, to help address the needs of larger and more complex projects. The RFP allowed proponents to propose variations to BC Hydro's preferred EPA terms and conditions.

Prior to launching the Clean Power Call, BC Hydro sought input from independent power producers (IPPs), other stakeholders and First Nations on the call and provided several opportunities for education and discussion on call design, proposed terms and conditions and process. Early Clean Power Call engagement efforts included dialogue sessions, workshops and an information session on BC Hydro's system needs. This provided an opportunity for stakeholders and First Nations to provide input on how system needs could be met through future calls. Following the release of the draft terms of the Clean Power Call, BC Hydro held an information session to improve understanding of the draft documents, encourage discussion and facilitate informed feedback. BC Hydro received over 40 submissions with approximately 600 written comments on the draft terms. Many submissions indicated a need for further discussion of residual rights, which refers to transfer of ownership of assets at the contract's end or a contract extension. As a result, BC Hydro held two additional dialogue sessions. Input received through the engagement process informed the design of the Clean Power Call and resulted in several changes to the terms and conditions of the call.

BC Hydro held two further sessions following the launch of the Clean Power Call. The first, held shortly after the call's issuance, provided potential participants with an overview of the revised RFP and EPA terms, the registration process and the timeline for the Clean Power Call, along with an overview of the transmission and distribution interconnection process. The second, held prior to the proposal submission deadline, provided registered proponents with the opportunity to review proposal requirements, EPA formulae and post-proposal submission processes.

Evaluating and Selecting Proposals

The RFP required that proponents and projects meet specific eligibility criteria. One of the main prerequisites was that all project output must qualify as clean or renewable electricity in accordance with the guidelines entitled "*British Columbia's Clean or Renewable Electricity Definitions*" published by the B.C. Ministry of Energy, Mines and Petroleum Resources and that a minimum of 25 GWh/year of seasonally or hourly firm energy be delivered. Other key RFP terms included providing proponents with a choice for their guaranteed Commercial Operation Date (between November 1, 2010 and November 1, 2016) and their preferred EPA term (between 15 to 40 years).

Proponents were strongly encouraged to submit proposals that conformed to the preferred terms and conditions provided in the Specimen EPA and to limit variations to substantive matters of significant importance or value (such as the inclusion of residual rights). BC Hydro's evaluation criteria were detailed in the RFP documents and the process for handling and evaluating submissions was established prior to bid submission. To ensure fairness in the evaluation process, an Independent Observer was retained to monitor the evaluation of proposals and any subsequent discussions with proponents, particularly those who disclosed prior relationships with BC Hydro or any B.C. Government entity. The process was confirmed to be fair and transparent by the Independent Observer, as noted in the report contained in Appendix B.

BC Hydro conducted a risk assessment of each proposal, examining aspects of the project including financial strength, technical aspects, First Nations engagement, permitting/approvals, and energy source data. BC Hydro reviewed any proposed variations to the EPA and completed a quantitative evaluation of proposed product and pricing attributes. Based on the results of these assessments, BC Hydro selected a number of proponents for post-proposal discussions focused on clarifying areas of risk, negotiating proposed variations, and seeking further price reductions.

Following these meetings, BC Hydro selected 27 projects for EPA awards based on the final EPA terms and conditions, including price, First Nations consultation, and risk assessment. BC Hydro acquired the Environmental Attributes from each project and also received residual rights in the form of term extension options for nine of the projects.

Achieving Cost-Effective Results for Ratepayers

The Clean Power Call was competitive and featured robust industry participation, providing BC Hydro with the ability to select some of the least-cost, best-value proposals from a large pool of submissions. The price to be paid for this electricity met BC Hydro's expectations based on comparisons to other BC Hydro processes and similar processes undertaken by other jurisdictions, and to 2008 LTAP projections. BC Hydro's Clean Power Call process has resulted in the acquisition of cost-effective clean, renewable electricity for BC Hydro's ratepayers.

2. BACKGROUND

a) Call Highlights and Context

Overview of the Clean Power Call Process

The Clean Power Call RFP was issued on June 11, 2008. It was structured as an RFP to allow more flexibility in working with IPPs and to come up with cost-effective EPA terms and conditions. The RFP approach was helpful in accommodating larger projects requiring additional development time and warranting Commercial Operation Dates (CODs) as late at November 2016.

In November 2008, BC Hydro received 68 proposals from 43 proponents, representing more than 17,000 GWh/year of energy. In November 2009, BC Hydro announced its decision to proceed with discussions aimed at securing EPAs with the 13 most cost-effective proposals. BC Hydro contacted the proponents of 34 additional proposals to afford them the opportunity to make their respective proposals more cost-effective. BC Hydro eliminated the remaining 21 proposals because the proposals were either withdrawn or did not meet the RFP requirements or were viewed as having excessive development risk.

On March 11, 2010 BC Hydro announced that it had selected 19 proposals for EPA awards under the Clean Power Call. Subsequently, eight additional proposals were selected for EPA awards with the last award occurring in early August 2010. The 27 selected proposals resulted in 25 EPAs (for one proponent, three proposals were combined into a single EPA) accounting for 3,266 GWh/year of firm energy and 1,168 MW of capacity. Based on an assumed attrition factor of 30 per cent, the EPAs account for 2,286 GWh/year of firm energy for planning purposes.

Context

The Clean Power Call is consistent with the 2007 Energy Plan and the British Columbia Utilities Commission (BCUC) endorsement of the Clean Power Call's clean or renewable eligibility criteria in the 2008 LTAP Decision.[1] Furthermore, the Clean Power Call is aligned with the British Columbia's energy objectives set out in section 2 of the Province's *Clean Energy Act (CEA)*.

The 2007 Energy Plan

The 2007 Energy Plan was released by the Province on February 27, 2007. The Clean Power Call aligns with Policy Action No. 21 of the 2007 Energy Plan, which indicates that clean or renewable electricity generation must continue to account for at least 90 per cent of total generation.[2]

Other 2007 Energy Plan Policy Actions relevant to the Clean Power Call are:

- **Policy Action No.10** – ensure self-sufficiency to meet electricity needs by 2016. Refer to Section 5 of the Report for BC Hydro's load/resource balance, including the two changes resulting from Special Direction No. 10 to the BCUC, namely: (a) the 2,500 GWh/year non-firm energy/market allowance has been removed from the energy load/resource balance after 2015; and (b) the 400 MW market reliance has been removed from the capacity load/resource balance after 2015. The BCUC endorsed these two changes as part of its 2008 LTAP Decision.[3]

- **Policy Action Nos. 18 and 19** – all new electricity generation projects will have zero net greenhouse gas (GHG) emissions by their CODs, and all existing thermal generation power plants will have zero net GHG emissions by 2016, respectively. The B.C. Government has legislated these two Policy Action items pursuant to the *Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008*[4] (*Emissions Standards Act*). Refer to Section 6 of the Report, where the EPAs are compared to a green-field generic 250 MW combined cycle gas turbine (CCGT) with 100 per cent of GHG emissions offset from its COD.

- **Policy Action No. 20** – require zero GHG emissions from any coal thermal electricity generating facilities. As part of its 2008 LTAP, BC Hydro examined the current status of coal-fired generation with carbon capture and sequestration (CCS) and concluded that coal-fired generation with CCS is not a commercial technology at this time.[5] Consequently the EPAs are not compared to coal-fired generation with CCS in Section 6 of the Report.

- **Policy Action No. 22** – replace the firm energy supply from Burrard Thermal Generating Station (Burrard) with other resources. On October 28, 2009, the B.C. Cabinet issued Direction No. 2 to the BCUC, which provides that the BCUC "must exercise its powers and perform its duties under the [*UCA*] in accordance with the criteria that … [BC Hydro] must plan to rely on Burrard for no more than … 0 GWh/year of firm energy". This is reflected in the energy load/resource balances set out in Section 5 of the Report.

BCUC 2008 LTAP Decision

In the 2008 LTAP Decision, the BCUC endorsed the Clean Power Call RFP clean or renewable eligibility criteria given the government's energy objectives.[6] Accordingly, natural gas-fired generation such as a CCGT was not eligible for the Clean Power Call. In Section 6 of this Report, BC Hydro compares the EPAs to a 250 MW CCGT with 100 per cent of GHG emissions offset from its COD. Given the BCUC's eligibility endorsement, a CCGT is not relevant in terms of whether the Clean Power Call ought to have been an "all source" power acquisition process.

Clean Energy Act

The C*lean Energy Act*, which was brought into force on June 3, 2010, contains several provisions which reinforce the 2007 Energy Plan including British Columbia's energy objectives of achieving electricity self-sufficiency and generating at least 93% of the electricity in B.C. from clean or renewable resources. The Clean Power Call aligns with both of these British Columbia energy objectives.

---

[1] *In the Matter of British Columbia Hydro and Power Authority and an Application for Approval of the 2008 Long Term Acquisition Plan*, *Decision*, 27 July 2009, page 124.

[2] Pursuant to the *Clean Energy Act* (*CEA*), S.B.C. 2010 c.22, section 2, the legislated clean, renewable electricity generation target is now at least 93 per cent.

[3] 2008 LTAP Decision, note 1, page 44 (with respect to the 2,500 GWh/year non−firm market allowance); and BCUC Order No. G-150-09, page 3 (with respect to the 400 MW of market reliance).

[4] S.B.C. 2008, c. 20. Given Royal Assent on May 29, 2008; the relevant part (section 2) in force by regulation.

[5] In a report entitled "*Clean Coal Power Generation by CO_2 Sequestration*", Powertech Labs Inc. concluded that the state of key components of CCS technology is such that it cannot be considered in commercial application of coal-fired generation. Although pilot plants are being considered and pursued, the viability of these technologies on a commercial application scale may not be known until 2017 or later. There are also legal, regulatory and public acceptance issues that likely need to be addressed before CCS technology can be considered on a commercial scale in B.C.

[6] 2008 LTAP Decision, note 1, page 124.

3. CALL IMPLEMENTATION AND EVALUATION

a) RFP Process

The acquisition process for the Clean Power Call employed an RFP process that allowed proponents to propose variations to BC Hydro's preferred EPA terms and conditions. In addition, the process allowed for direct negotiation of price and terms between BC Hydro and a proponent. BC Hydro's F2006 Call used a Call for Tenders (CFT) process, which offered limited flexibility and no opportunity for negotiation of price and other material terms and conditions.

The Clean Power Call RFP was issued on June 11, 2008. In October 2008, BC Hydro retained John Singleton of Singleton Urquhart LLP to act as an Independent Observer for the implementation of the Clean Power Call. His main role was to monitor the evaluation of proposals and any subsequent discussions with proponents, particularly those proponents who disclosed prior relationships with BC Hydro or any B.C. Government entity. The Independent Observer also assessed whether any unfair bias was shown in favour of any proponent.

A process for handling and evaluating submissions was established prior to bid submission. Figure 3-1 outlines the evaluation process. The evaluation criteria for the RFP were laid out in section 20 of the RFP.

The RFP evaluation process began with the receipt of proposals in November 2008. The RFP process was completed in August 2010 with the award of the final EPA. In total, BC Hydro awarded 25 EPAs for 27 projects to 18 different Clean Power Call proponents.

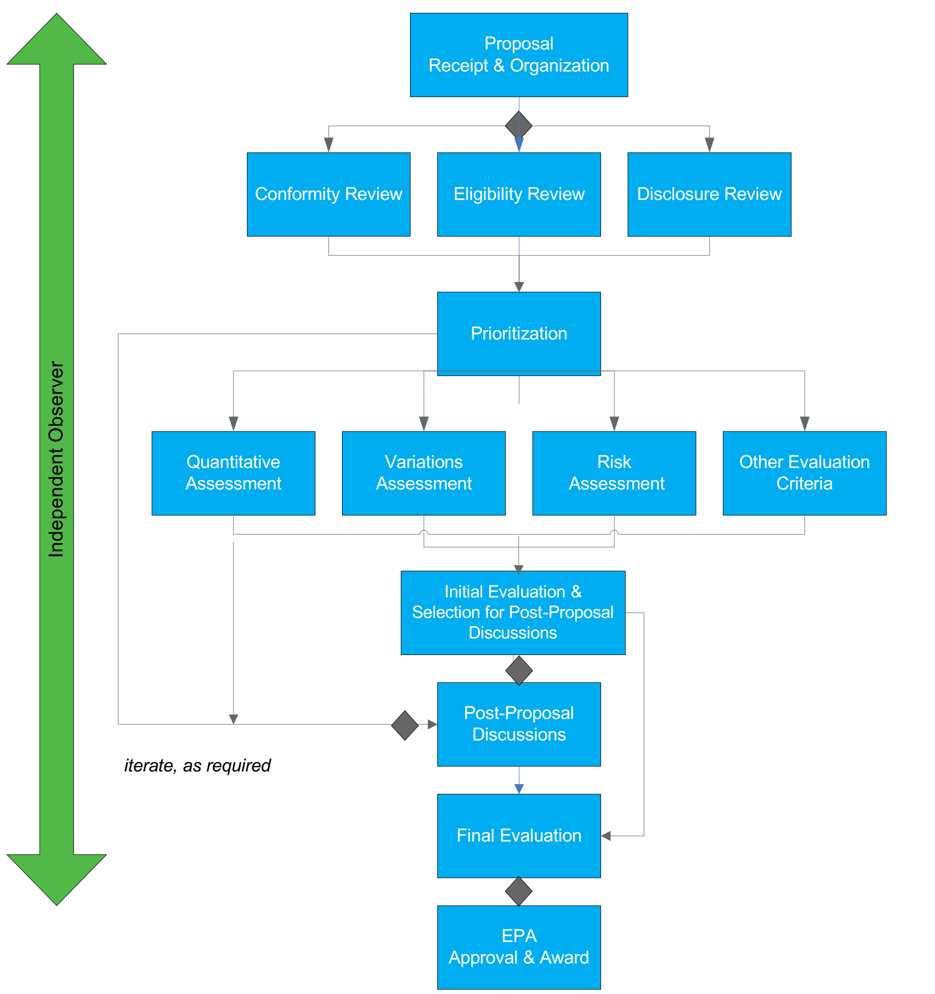
b) RFP Overview

The key preferred EPA terms and conditions of the Clean Power Call RFP are summarized below.

Product

BC Hydro defines "firm energy" as a volume of energy with a contractually assured delivery, which a proponent must commit to delivering over a specified period. Proponents were permitted to make a commitment to either seasonally or hourly firm energy deliveries. Seasonally firm energy refers to the volume of energy that a proponent commits to deliver to

Figure 3-1 Clean Power Call RFP Evaluation Process



BC Hydro in a season (i.e., in specified three-month periods). Hourly firm energy refers to the volume of energy that a proponent commits to deliver in each hour.

Fuel Type

The entire output from a project bid into the Clean Power Call was required to qualify as clean or renewable electricity in accordance with the "*British Columbia's Clean or Renewable Electricity Definitions*" published by the B.C. Ministry of Energy, Mines and Petroleum Resources. All fuel types meeting these definitions were eligible in the Clean Power Call, other than forest-based biomass.

Project Size

All proponents bidding into the Clean Power Call were required to commit to delivering a minimum of 25 GWh/year of firm energy.

Commercial Operation Date (COD) and Term

Proponents were permitted to select a guaranteed COD between November 1, 2010 and November 1, 2016 and an EPA term ranging from 15 to 40 years, commencing from the COD. The latter COD timing is in alignment with the 2007 Energy Plan, which indicates that B.C. is to achieve electricity self-sufficiency by 2016, and allows larger projects with extended CODs to be accommodated. The term length is based on permitting considerations and the typical life of clean and renewable technologies.

Liquidated Damages (LDs)

After the first anniversary of COD, LDs are payable to BC Hydro (either on an hourly or seasonal basis) for firm energy delivery shortfalls. The amount of LDs is the greater of market price less the firm energy price (adjusted for delivery to the Lower Mainland) and $5.00 (adjusted annually for Consumer Price Index (CPI) from January 1, 2009) for each MWh of delivery shortfall. The total firm energy delivery shortfall LDs for each year are limited to an amount equal to 200 per cent of the performance security for that year.

c) Proposal Submissions

A total of 75 proponents with 168 separate projects totalling almost 18,000 MW of nameplate capacity registered for the Clean Power Call RFP on August 12, 2008. Proposals were due on November 25, 2008. BC Hydro received 68 project proposals from 43 different proponents representing approximately 17,000 GWh/year of firm energy. The submissions included 45 hydro projects, 19 wind projects, two waste heat projects, one biogas project, and one biomass project.

Following the receipt of proposals, conformity and eligibility reviews were conducted with the assistance of outside legal counsel. No proposals were disqualified based on the conformity review but seven proposals were eliminated based on failure to meet the eligibility requirements.

d) Risk Assessment

BC Hydro conducted a Risk Assessment to assess the development and delivery risks associated with each proposal.

Process

Each proposal was assessed by five separate Risk Assessment teams consisting of BC Hydro staff and external consultants with relevant expertise. Each team focused on reviewing one of five discrete risk areas being assessed: financial, technical, First Nations, permitting/approvals and energy source. Each Risk Assessment team was requested to review only those areas of the proposal relevant to their assessment and none of the teams had access to the commercial elements of the proposals, which contained bid price information and other commercial terms.

Each Risk Assessment team developed a risk rating for each project, in their respective area of focus, on a scale of low, medium or high. Ratings were based on criteria defined by each team prior to receiving proposals. In addition to the ratings, the Risk Assessment teams provided a brief summary of the major risks for each project. The review by the Risk Assessment teams was completed by February 2009.

The Risk Assessment teams were tasked with evaluating the following aspects of all proposals:

1. **Finance:** This team evaluated the financial strength of proponents and their partners in relation

to the capital required to develop the projects. This team also assessed whether there was a risk of the project not being developed due to a lack of debt or equity financing.

2. **Technical:** This team assessed the technical aspects of project development, including the feasibility of the construction schedule and the operational plans proposed by proponents.

3. **First Nations:** This team initially assessed the engagement activities of the proponents with First Nations and assessed the extent of any development risk, particularly related to permitting. After February 2009, as the result of a court decision, EPA filings with the BCUC needed to contain an assessment of the adequacy of First Nations consultation with respect to projects receiving EPA awards. To prepare for its BCUC filing requirements, BC Hydro assessed the adequacy of First Nations consultation undertaken by proponents for all projects being considered for EPA awards.

4. **Permitting and Approvals:** This team assessed project development with respect to obtaining the necessary permits and approvals. This assessment included a determination of whether the necessary permits and approvals have been identified as well as the reasonableness of the plan and schedule for obtaining any outstanding permits and approvals and the risks to receiving these permits and approvals.

5. **Energy Resource:** This team reviewed the energy source data submissions. The energy source data was assessed for the strength of data, data analysis and modeling methodology to ascertain the resource availability for the proposed projects. An analysis reflecting the energy expected versus the firm energy profile contained in the proposals was also undertaken.

Results

Upon completion of the individual Risk Assessment for each of the five risk categories described above, the results were calibrated across the various projects and aggregated by project to generate an overall development and delivery risk rating for each project.

The Risk Assessment was not intended to be used as a pure pass or fail decision, although BC Hydro retained the right to remove any proposal from consideration on the basis of risk. BC Hydro exercised this right in situations where reasonable development efforts had not been demonstrated by the proponent, or where the risks associated with project development made it unattractive to pursue. In November 2009, BC Hydro rejected 10 Clean Power Call proposals based on excessive development risk.

e) Variations Review

The Specimen EPA issued on October 21, 2008 represented BC Hydro's preferred terms and conditions. The Specimen EPA was based on an IPP project proposed by a single corporation, offering seasonally firm energy with a direct interconnection to the transmission system. Some proponents were able to offer additional value to BC Hydro or had unique situations not contemplated in the Specimen EPA. To accommodate such situations, BC Hydro indicated it would consider two types of variations to the Specimen EPA:

- **Essential Variations** – modifications to the Specimen EPA necessary to enable the proponent to design, build and operate its project in compliance with the EPA. Essential variations were to be included in the offered Firm Energy Price (FEP).

- **Value Variations** – modifications, generally value enhancements, to the Specimen EPA that BC Hydro could choose to incorporate into the EPA. Value variations could be priced with a modification to the offered FEP.

In submitting variations, proponents were requested to submit a redlined version of the Specimen EPA, with a brief commentary indicating: (i) whether variations were essential variations or value variations, and (ii) the reasons for the variations. In the event that the variation(s) could not be captured by marking up the Specimen EPA, the proponent had the option of submitting a separate document describing the proposed variations in place of or in addition to the redlined Specimen EPA. Proponents were strongly encouraged to submit proposals that conformed to the preferred terms and conditions, to limit variations to matters of significant importance, and not to expect post-proposal discussions (i.e., sufficient information was required in the variation proposals to facilitate full assessment by BC Hydro).

The Variation Review team assessed the variations proposed by each proponent. In some situations, the proposed variations were modified and/or additional value variations were proposed by proponents following post-proposal discussions. These modified and/or additional variations were also reviewed by the Variation Review team. Variations that were acceptable to BC Hydro were incorporated into the EPAs for those projects selected for awards.

f) Quantitative Evaluation

The Clean Power Call RFP permitted proponents to select a number of different options (e.g., product and pricing attributes) when submitting their proposals. As a result, a process was required to fairly compare one proposal against another. To compare proposals with different attributes, an adjusted Firm Energy Price (FEP) was calculated for each proposal. The first step in computing the adjusted FEP was to levelize the offered FEPs, which took into account the pricing attributes chosen by the proponents. The second step was to adjust the levelized FEPs for product attributes and for project location relative to the Lower Mainland.

Step 1: Levelizing the FEPs

To compute the levelized FEP, BC Hydro divided the present value (PV) of the firm energy purchases for each proposal, based on the proponent's selected options (e.g., COD, contract term, escalation rate), by the PV of firm energy flow to be delivered over the term of the EPA. The nominal discount rate used for the PV calculation was 8 per cent, including a 2.1 per cent inflation component.

Step 2: Price Adjustments

The levelized FEP was adjusted to account for differences in product attributes, and in project location relative to the Lower Mainland. Adjustments were made for hourly firm energy, wind integration, Network Upgrade (NU) costs borne by BC Hydro, Cost of Incremental Firm Transmission (CIFT) and energy losses.

Hourly Firm: An adjuster (expressed in $/MWh) was deducted from the levelized FEP for proponents that committed to deliver hourly firm energy. The magnitude of the adjuster depended on the proponent's profile of on-peak hourly firm energy. For a project with a “flat” hourly firm energy profile, the adjuster was approximately $4.00/MWh.

Wind Integration: Due to the intermittent and variable nature of wind energy output, a $10/MWh adjustment was added to the levelized FEP of wind projects to account for the incremental cost of integrating wind projects into the BC Hydro generation system.

Network Upgrades: The NU adjustment was based on an estimate of the costs borne by BC Hydro to interconnect projects to the grid. The estimated NU costs were provided in interconnection studies conducted on a stand-alone basis for each project. The applicable NU amounts were multiplied by 150 per cent and converted into a $/MWh adjustment and then added to the levelized FEP offered by the proponent.

CIFT: The CIFT adjustment was based on a report entitled “*Bulk Transmission System Cost of Incremental Firm Transmission for BC Hydro's 2008 LTAP Base Plan and Contingency Resource Plans CRP1 and CRP2*” dated January 15, 2009. The CIFT provides a general indication of the long term unit cost of bulk transmission system reinforcement from one region to the next region. The CIFT for non-adjacent regions can be determined by summing the region to region costs. To calculate the CIFT adjustment for each project, CIFT costs (expressed in $k/MW-year) for the largest incremental flows in the F2010 Stage[7] were used. The cumulative CIFT costs for each project were converted into a $/MWh adjustment and then added to the levelized FEP for that project.

Losses: Studies were conducted to determine the losses associated with delivering the energy from each project location to the Lower Mainland on a stand-alone basis. These losses were converted into a $/MWh adjustment and added to the levelized FEP price for the project.

The result of the above adjustments is a levelized adjusted FEP on a stand-alone basis for a common product, i.e., seasonally firm energy delivered to the Lower Mainland.

Projects that were part of a “transmission cluster” were further evaluated for cost-effectiveness. A transmission cluster is defined as a group of projects that trigger network upgrades that are in addition to their stand-alone NU requirements as a result of their relative locations on the transmission system. In evaluating a transmission cluster, the incremental cost of the additional network upgrade was allocated to each project in the cluster on a pro-rated basis.

g) Discussions and EPA Variations

Based on the results of the Risk Assessment, Variation Assessment and Quantitative Assessment, BC Hydro selected more than half of proponents and projects for an initial round of post-proposal discussions which took place in March and April 2009. For these discussions, projects were selected primarily on the basis of price and strategic interest (e.g. location, storage capability). Discussions were focussed on seeking clarification on any areas of risk, negotiating any proposed variations to the Specimen EPA, and seeking further price reductions. As a result of these discussions, price reductions were received for several projects.

In November 2009, 21 proposals, representing approximately 4,200 GWh/year of firm energy, were eliminated from the Clean Power Call because the proponents had withdrawn their proposals, the proposals did not meet the requirements of the RFP or the proposals were considered to have too high a level of risk. Thirteen proposals were identified as the most cost-effective and further discussions aimed at securing EPAs, as well as further price reductions, were carried out with the proponents of these proposals. The proponents of the remaining 34 proposals were given an opportunity to make their proposals more cost-effective.

Discussions with the proponents of the 47 remaining proposals commenced in November 2009. These final discussions continued to focus on clarifying any areas of risk, but also sought residual rights (either in the form of a term extension option for BC Hydro or ownership rights, if the project was considered to be of strategic interest due to, for example, size or storage capability), any additional information required to conclude the First Nations consultation assessment, and resolution of any variations to the Specimen EPA. The Risk, Variation, and Quantitative Assessments were updated as necessary following all discussions.

h) Final Portfolio Selection

Based on the outcome of the meetings described above, 27 projects, representing 3,266 GWh/year of firm energy, were selected to receive EPAs, as summarized in Table 3-2. Three of the projects from one proponent were combined into a single EPA; thus, a total of 25 EPAs were awarded. A more detailed listing of the projects being awarded EPAs is contained in Appendix A.

The decision to offer EPAs to these 27 projects was based on the final EPA terms and conditions, including the prices offered by the proponents, the adequacy of First Nations consultation, and the Risk Assessment. Also, the proponents of nine of the selected projects provided residual rights to BC Hydro in the form of term extension options.

i) Summary of RFP Proposals

Table 3-3 summarizes the treatment of the RFP proposals, starting with the receipt of proposals in November 2008 and culminating with the final EPA awards in July 2010.

Table 3-2 Summary of Projects for Awarded EPAs

Proponent Name	Project Name	Location	Energy Source	Capacity (MW)	Firm Energy (GWh/yr)
AltaGas Ltd.	Crowsnest Pass Power	Sparwood	waste heat	11	46
Box Canyon Hydro Corporation and Sound Energy Inc.	Box Canyon	Port Mellon	hydro	15	50
Castle Mountain Hydro Ltd.	Benjamin Creek	McBride	hydro	6	27
C-Free Power Corp.	Jamie Creek	Gold Bridge	hydro	19	41
Cloudworks Energy Inc.	Big Silver-Shovel Creek	Harrison Hot Springs	hydro	37	110
Cloudworks Energy Inc.	Northwest Stave River	Mission	hydro	18	44
Cloudworks Energy Inc.	Tretheway Creek	Mission	hydro	21	56
CP Renewable Energy (B.C.) Limited Partnership	Quality Wind	Tumbler Ridge	wind	142	434
Creek Power Inc.	Boulder Creek	Pemberton	hydro	23	48
Creek Power Inc.	North Creek	Pemberton	hydro	16	34
Creek Power Inc.	Upper Lillooet River	Pemberton	hydro	74	143
ENMAX-Syntaris Bid Corp.	Culliton Creek	Squamish	hydro	15	56
Finavera Renewables Inc.	Bullmoose Wind	Tumbler Ridge	wind	60	142
Finavera Renewables Inc.	Meikle Wind	Tumbler Ridge	wind	117	327
Finavera Renewables Inc.	Tumbler Ridge Wind	Tumbler Ridge	wind	45	140
Finavera Renewables Inc.	Wildmare Wind	Chetwynd	wind	71	204
Pacific Greengen Power	Bremner / Trio	Harrison Hot Springs	hydro	45	148
Kwagis Power Limited Partnership	Kokish River	Port McNeill	hydro	45	183
Long Lake Joint Venture	Long Lake	Stewart	hydro	31	139
NI Hydro Holding Corp.	Ramona 3 + Chickwat Creek + CC Creek	Sechelt	hydro	45	198
Plutonic Power Corporation / GE Energy Financial Services Co.	Upper Toba Valley	Powell River	hydro	124	214
Run of River Power Inc.	Mamquam	Squamish	hydro	25	68
Sea Breeze Energy Inc.	Knob Hill Wind	Port Hardy	wind	99	281
Selkirk Power Company Ltd.	Beaver River	Golden	hydro	44	86
Swift Power Corp.	Dasque-Middle	Terrace	hydro	20	46
TOTAL				1,168	3,266

Table 3-3: Treatment of RFP Proposals

Event	Date	Proponents	Proposals	Firm Energy (GWh/year)
RFP Submissions	Nov. 2008	43	68	17,700
Eliminations due to: • Conformity Review • Eligibility Review • Risk Assessment • Withdrawal		(12)	- (7) (10) (4)	(4,200)
Short-listed Proposals	Nov. 2009	31	47	13,500
Eliminations due to: • Not Cost Effective • Excessive Risk		(13)	(17) (3)	(10,234)
Completion of EPA Awards	July 2010	18	27	3,266

Table 3-4 shows a comparison of bid prices for the proposals selected for EPA awards. EPAs were awarded to lowest cost short-listed proposals in terms of levelized adjusted FEP with the exception of three short-listed proposals which were rejected due to excessive development risk.

Table 3-5 summarizes key data for the projects selected for EPA awards. As shown, most of the projects are run-of-river hydro and comprise nearly 60 per cent of the total energy. However, the six wind projects account for almost half of the total firm energy.

The weighted-average energy prices shown in Table 3-5 (except for the adjusted FEP) are typically measured at the plant gate level. The derivation of these plant gate prices is briefly summarized in Table 3-6.

As shown in the jurisdictional comparison contained in Section 6 of this Report, the energy prices being paid under BC Hydro's Clean Power Call compare favourably with renewable power prices being paid by other electric utilities in North America.

Table 3-4: Price Comparison for Awarded EPAs

Project Number	Firm Energy - $/MWh			Total Energy - $/MWh
	Final Bid Price (Jan. 2009$)	Levelized Plant Gate Price	Levelized Adjusted FEP	Levelized Plant Gate Price
1	137.00	105.08	105.36	99.55
2	105.00	100.11	107.40	85.70
3	120.00	107.32	112.24	93.70
4	137.92	113.93	113.83	97.82
5*	99.00	89.97	117.37	86.60
6	113.70	117.54	117.76	94.19
7	95.00	83.05	120.81	76.21
8	143.50	104.25	122.44	83.41
9	149.64	122.53	122.66	103.74
10	156.00	119.92	124.32	115.16
11	144.00	119.53	124.54	118.48
12*	102.25	92.92	125.95	89.72
13*	109.00	99.05	126.32	94.89
14	148.00	130.65	126.95	107.20
15	151.89	127.77	127.30	105.93
16	148.00	115.82	127.40	90.40
17*	123.14	108.77	128.16	105.75
18	138.10	124.88	129.48	108.63
19	130.00	115.10	130.25	115.10
20*	108.00	98.15	131.49	94.06
21	135.87	125.60	132.34	106.53
22	143.90	121.23	132.90	119.62
23	155.43	124.67	133.80	95.30

Notes:

a) Projects are listed based on the ranking of the levelized adjusted Firm Energy Price (FEP) which was the evaluation benchmark for decision-making purposes.

b) The five projects flagged with an asterisk (*) were included in "transmission clusters" which resulted in incremental network upgrade costs. The allocation of these costs resulted in adjusted FEP figures which were $3-4 per MWh higher than those shown in the table, which were calculated on a stand-alone project basis.

c) Prices are shown for 23 EPAs rather than the 25 awarded given that there is a composite price figure for one proponent with 3 EPAs reflecting a common Network Upgrade for all 3 of its projects.

In its decision making for cost-effective awards, BC Hydro used the levelized adjusted Firm Energy Price since it places all projects on a level footing by adjusting for varying escalation factors and a common delivery point (i.e. Lower Mainland). As shown in Table 3-5, the levelized adjusted FEP for the projects selected ranged from $105.4 to $133.8 per MWh with a weighted-average adjusted FEP of $124.3/MWh, with little difference between hydro and wind projects.

Table 3-5: Key Data for Projects with EPA Awards*

	Hydro	Wind	Total**
Number of Projects	20	6	27
Firm Energy (GWh/year)	1,692	1,528	3,266
Total Energy (GWh/year)	2,342	1,644	4,051
Firm Energy Price ($/MWh)			
Final Bid Price (Jan. 2009 $)	95.0 to 156.0	99.0 to 143.9	95.0 to 156.0
Weighted-Average Bid Price	139.9	116.6	128.5
Levelized Plant Gate Price	83.1 to 130.7	90.0 to 121.2	83.1 to 130.7
Weighted-Average Plant Gate Price	118.0	103.1	111.3
Levelized Adjusted FEP	105.4 to 133.8	117.4 to 132.9	105.4 to 133.8
Weighted-Average Adjusted FEP	123.0	126.5	124.3
Total Energy Price ($/MWh)			
Levelized Plant Gate Price	76.2 to 118.5	86.6 to 119.6	76.2 to 119.6
Weighted-Average Plant Gate Price	101.7	99.6	100.7

* Prices shown are on a stand-alone project basis.

** Includes one waste heat project which is not segregated for confidentiality reasons.

The weighted-average levelized and adjusted FEP of $124.3/MWh is a reasonable proxy for the costs that will be borne by BC Hydro's ratepayers for electricity being acquired pursuant to the Clean Power Call. BC Hydro's future Revenue Requirements Applications (RRAs) will include the total cost of energy being purchased under the awarded EPAs (i.e., the cost of all firm and non-firm energy and associated losses) as the projects reach COD and begin delivering energy. In addition, future RRAs will reflect the cost of capital additions for upgrading the transmission and distribution systems in order to connect the IPP projects to BC Hydro's grid.

Table 3-6: Derivation of Plant Gate Prices

Final Bid Price for Firm Energy (Plant Gate)	$128.5/MWh	Contractual EPA price (stated in Jan. 2009$) which is escalated each year based on escalation factors chosen by proponents
Levelized Plant Gate Price for Firm Energy	$111.3/MWh	Price in 2009$ derived from a present value calculation (using an 8% discount rate) which adjusts for varying escalation rates, CODs and EPA terms; lower than contractual bid price since post-COD escalators limited to 0-50% of CPI
Levelized Plant Gate Price for Total Energy	$100.7/MWh	Blended price for both firm and non-firm energy. Non-firm energy comprises about 20% of total deliveries and is priced at market levels which is lower than the FEP

j) Independent Observer's Report

The Independent Observer's report regarding the Clean Power Call RFP process is contained in Appendix B. The Independent Observer concluded that "... the process has been fair, transparent and without any demonstrated bias shown towards any particular proponent".

[7] F2010 Stage refers to the facilities that are expected to be in service in F2010 and later.

4. FIRST NATIONS AND STAKEHOLDER ENGAGEMENT

a) Dialogue and Information Sessions

The Clean Power Call engagement process built upon the previous engagement efforts of the F2006 Call Open Call for Power. During summer 2006, BC Hydro engaged IPPs in a series of dialogue sessions to solicit input into the design of the Clean Power Call, including improvements to the acquisition process and enhanced contractual terms and conditions. BC Hydro held a follow-up workshop with some of the IPP dialogue participants and included the B.C. Government and representatives from the financial, construction and legal communities, to discuss call design and to further explore key themes identified during the dialogue sessions. In mid-2007, BC Hydro hosted an information session titled "*Understanding BC Hydro's System Needs*", which detailed BC Hydro's system needs, short-term and long-term system planning and system constraints. Input was sought from First Nations, and from IPPs and other stakeholders, on how to meet system needs through future calls.

BC Hydro released the proposed terms of the Clean Power Call on November 14, 2007 and sought input on these terms from First Nations, and stakeholders including IPPs and the B.C. Government. To improve the understanding of the draft documents and to encourage discussion and facilitate informed feedback, BC Hydro held an information session on the proposed design of the Clean Power Call in Vancouver in November 2007. Following this session, BC Hydro received over 40 submissions with about 600 written comments on the draft Term Sheet documents. Many of these submissions highlighted the need for further discussion about including residual rights as a call term. As a result, two small dialogue sessions were held around year-end 2007 to discuss the potential impacts on call participants and to explore options that would make it worthwhile for the industry to consider residual rights.

Input received through the engagement process was used to inform the design of the Clean Power Call terms and EPA. The RFP terms were released June 11, 2008. A full-day engagement session for potential applicants and interested parties was held in July 2008. BC Hydro reviewed and provided details on the RFP terms, registration process and timeline followed by a BCTC overview of the details and deadlines for the interconnection processes.

BC Hydro held a final engagement session for Clean Power Call proponents in October 2008. Proponents were encouraged to attend the session to review proposal requirements, the application process, specimen EPA formulae and post-proposal submission processes.

Details of these sessions are further summarized in Table 4-1.

b) First Nations Engagement Regarding RFP Design

First Nations were invited to participate in all of BC Hydro's engagement activities listed above. BC Hydro also held two sessions for First Nations only. Representatives from BC Hydro, the Ministry of Environment, Integrated Land Management Bureau, and the Environmental Assessment Office were available to address questions raised by the session participants. One session was held prior to the Clean Power Call being released to provide participants an opportunity to comment on the draft RFP terms and offer improvements. A second session was held after the RFP was issued to explain the final terms of the Clean Power Call.

Invitation letters for these two sessions were sent to more than 200 First Nations and approximately 30 tribal councils within B.C. In the invitation, BC Hydro offered to cover travel and accommodation expenses to ensure that travel costs were not a participation barrier.

Table 4-2 provides a summary of the First Nations specific engagement sessions conducted before and after the Clean Power Call was launched.

Comments received from First Nations contributed to BC Hydro's decision making on the treatment of residual rights. Most comments from First Nations were not directly applicable to the terms of the Clean Power

Table 4-1: Summary of Dialogue and Information Sessions

Session	Description	Outcome
IPP Dialogue Sessions Summer 2006: ▪ June 29 ▪ July 5,10,11,14,18 and 21 ▪ August 9 and 15	These dialogue sessions were designed to stimulate discussion and identify items that should be considered as part of the Clean Power Call, including improvements to the acquisition process and enhanced contractual terms and conditions.	*9 sessions were held with 37 participants.* Key issues included: • Learnings from F2006 Call • Types of acquisition process (structured CFT or RFP) • Risk allocation • EPA terms • Reducing attrition • Transmission issues Feedback obtained at these sessions helped to inform the design of the draft terms of the Clean Power Call. Sessions summaries were completed and posted on BC Hydro's website.
Workshop on Clean Power Call Design September 21, 2006	BC Hydro gathered with IPPs, BCTC, the B.C. Government and representatives from the financial, construction and legal communities to have a broad discussion regarding design of the Clean Power Call and to explore possible solutions for several key themes identified during the IPP dialogue sessions.	*30 attendees participated in this broad discussion.* Participants worked in break-out groups to discuss financial, transmission/interconnection, construction, permitting and EPA issues. Feedback obtained at these sessions helped to inform the design of the draft terms of the Clean Power Call. A workshop summary was posted on BC Hydro's website.
Understanding BC Hydro's System Needs June 6, 2007	This session was designed to create a greater understanding of BC Hydro's system needs, long and short-term system planning and system constraints and to obtain input on how to meet system needs through future calls.	*185 registered participants* Presentations from this session were posted on BC Hydro's website.
Clean Power Call Information Session November 27, 2007	This session gave BC Hydro a chance to provide more details on the Clean Power Call and offered an opportunity for participant questions and provide feedback on the Clean Power Call and the draft Term Sheet documents. Several break-out group sessions were also organized during the afternoon to allow for more in-depth discussion on specific issues.	*145 registered participants* Participant feedback was considered in terms of refining the Clean Power Call. Key issues were: • Treatment of Environmental Attributes • Residual rights inclusion in the Clean Power Call • Freshet caps • Wind integration costs
Residual Rights Dialogue Sessions December 12, 2007 January 15, 2008	Smaller dialogue sessions were used to review and explore the inclusion of residual rights terms in the Clean Power Call.	*Each session consisted of a working group of approximately 20 attendees.* Key issues were: • Impact on competitiveness and pricing • Creation of additional land use conflict • Motivation for including residual rights in the draft terms • Project lifespan and actual value of plant at transfer
BC Hydro/BCTC Joint Information Session on Clean Power Call RFP July 8, 2008	The morning session, hosted by BC Hydro, provided potential participants with an overview of the revised RFP and contract terms, the registration process and the timeline for the Clean Power Call. The afternoon session, hosted by BCTC, provided an overview of the important details and timelines for the transmission and distribution interconnection processes.	*Over 302 registered participants* Presentations from this session were posted on BC Hydro's website.
Proponent RFP Information Session October 23, 2008	Registered proponents were given an opportunity to review proposal requirements, specimen EPA formulae and post-proposal submission processes.	*162 registered participants* Questions dealt with all aspects of the RFP process.

Table 4-2: First Nations Engagement Sessions

Session	Description	Outcome
Information Session on Draft Clean Power Call Terms December 6, 2007	Participants were provided with an overview of the draft terms and conditions of the Clean Power Call.	*22 registered participants* Feedback from this session focused on a number of issues including: • General dissatisfaction with residual rights clauses • Capacity funding • Treatment of First Nations consultation in the risk assessment stage of the RFP
Information Session after Issuance of Clean Power Call RFP July 10, 2008	Participants were provided with an overview of the terms of the Clean Power Call RFP.	*24 registered participants* Feedback from this session focused on a number of issues, including: • Responsibility for consultation between the proponent, government or BC Hydro • First Nations' access to resources for development opportunities Identification of revenue sharing opportunities for First Nations and potential sources

Call; however, the comments received have been considered for BC Hydro's subsequent engagement processes.

c) Reasonableness and Adequacy of First Nations Consultation

Prior to entering into the EPAs, BC Hydro reviewed the First Nations consultation records of Clean Power Call proponents to determine if consultation had been reasonable and adequate. The Information and documentation requested by BC Hydro from proponents was as follows:

First Nations Identification

Information that identified how proponents determined which First Nations to consult with in relation to their projects including:

- A statement of how proponents determined which First Nations to consult and a list of such First Nations (including key contact persons); and
- Copies of directions from other Crown agencies indicating the specific First Nations to be consulted with as well as supporting documentation such as letters from First Nations or tribal councils and letters from other Crown agencies such as the Integrated Land Management Bureau, which is responsible for administering and adjudicating B.C. Crown land tenures as well as coordinating permitting for clean energy projects.

Project Impacts on First Nations Interests

To assess the potential degree of the project impacts on asserted aboriginal rights and title, BC Hydro considered:

- Information on the level of consultation to this stage such as the nature of information shared with First Nations about the project, the opportunities for First Nations to identify potential impacts, when consultation began (and how frequently consultation occurred) and plans for future consultations;
- Detailed information on each impact to any First Nation's asserted title and rights that had been identified, either by the First Nation or through studies related to the project (such as archaeological studies or Traditional Use Studies);
- Information on how the severity of the impact was assessed and whether First Nations were involved in assessing the severity of the impact;
- Mitigation measures that had been identified by the proponent and whether those mitigation measures addressed First Nations concerns;
- In respect of permits that have not yet been issued

by Crown agencies, identification of any concerns raised by First Nations in the permitting process; and

- Identification of all permits, licenses, tenures and approvals that had been rejected due to lack of adequate First Nations consultation.

Consultation Activities

The following documentation relating to First Nations consultation for the project:

- Consultation reports and consultation logs;
- Meeting minutes or records;
- Impact benefit agreements, memoranda of understanding, protocols or similar agreements with First Nations that validated the proponent's consultation;
- Information on how any commitments to First Nations have and/or would be undertaken;
- Letters of support or objection from First Nations;
- Correspondence between the proponent and First Nations;
- Band Council resolutions or similar authorizations; and
- Permits obtained from Crown agencies and correspondence between the proponent and Crown agencies concerning First Nations issues.

For the 25 awarded EPAs, BC Hydro determined that the consultation processes to this stage were reasonable and adequate.

a) Products

Firm Energy

BC Hydro pays for the firm energy that is received at the price in the EPA for that year multiplied by a time-of-delivery factor to account for the value of energy to BC Hydro at different time periods in a month and for different months in the year. The three by twelve (three time periods per month by 12 months) time-of-delivery factors are common to all EPAs.

The Super-Peak period is from hours 16:00 to 20:00, and the Peak period is from 6:00 to 16:00 and from 20:00 to 22:00 from Monday to Saturday. The Off-Peak period is from 22:00 to 6:00 from Monday to Saturday and includes all hours on Sundays and B.C. statutory holidays.

Table 5-3: Time of Delivery Factors

	Super-Peak [%]	Peak [%]	Off-Peak [%]
January	141	122	105
February	124	113	101
March	124	112	99
April	104	95	85
May	90	82	70
June	87	81	69
July	105	96	79
August	110	101	86
September	116	107	91
October	127	112	93
November	129	112	99
December	142	120	104

Non-Firm Energy

In addition to the firm energy being acquired under the Clean Power Call, BC Hydro will be purchasing approximately 800 GWh/year of non-firm energy which represents about 20 per cent of the total energy deliveries. Payment for any non-firm energy delivered is based on two pricing options provided to proponents. At the time of proposal submission, proponents elected to be paid for their non-firm energy deliveries based on either a fixed price schedule (Option A) reflecting BC Hydro's forecast of market electricity prices or a variable price (Option B) based on actual average spot market prices (Mid-Columbia) for non-firm energy.

Environmental Attributes

"Environmental Attributes" are another product BC Hydro is acquiring as part of the Clean Power Call. The term "Environmental Attributes" is broadly defined in Appendix 1 of the Specimen EPA to include all rights and benefits of any kind associated with, or airing from, a project's "greenness", including any green marketing attributes, offsets, credits or other instruments or rights arising from the actual or assumed displacement by the project of offsite emissions, as well as any offsets, credits, allowances or other tradeable rights arising from on-site emission reductions.

There are strong reasons for BC Hydro to acquire the Environmental Attributes from IPPs as part of the Clean Power Call:

- Most importantly, BC Hydro is not acquiring clean or renewable electricity if it purchases electricity without the Environmental Attributes. Such electricity would be considered as "null" electricity[8] in most jurisdictions since it no longer has any associated environmental benefits.

- There is a potential GHG liability from acquiring null electricity stripped of the Environmental Attributes because null electricity may have some GHG intensity, whereas clean electricity has no or very low GHG intensity.

- The acquisition of Environmental Attributes as part of a clean, renewable power acquisition process is consistent with procurement/acquisition processes of other utilities. With the exception of United States (U.S.) jurisdictions issuing standard offer-like acquisition processes under the *Public Utility Regulatory Policies Act* of 1978, for those jurisdictions for which information could be obtained, the Environmental Attributes are transferred to the purchasing utility;[9]

- Acquisition of the Environmental Attributes permits BC Hydro to manage risk in the event that at some point a Renewable Portfolio Standard is set for BC Hydro.

Environmental Attributes acquired through the Clean Power Call may be marketed to buyers in B.C., the Western Electricity Co-ordinating Council (WECC) region and other markets for the benefit of BC Hydro's ratepayers. BC Hydro's assumption is that the Environmental Attributes could generate between $3/MWh and $18/MWh if sold in the WECC region.

b) Need for New Resources

The need for energy from the Clean Power Call EPAs must be considered with respect to BC Hydro's load/resource balance and future resource requirements.

Energy Load/Resource Balance – Existing and Committed Resources

The load/resource balance for the early portion of the planning horizon based on existing and committed resources, net of Demand Side Measures (DSM), is provided in Table 5-1. For clarity, these figures do not reflect any supply-side resources that have not been fully committed. It shows that substantial resource additions are required with a resource gap of 600 GWh in F2013 growing to 4,100 GWh in F2017.

Table 5-1: Energy Load/Resource Balance for Existing & Committed Resources

(GWh/year)	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020
Energy Gap	-600	-900	-1400	-1900	-4100	-4700	-5300	-5300

The following considerations are relevant to the energy load/resource balance:

- BC Hydro used its 2009 mid Load Forecast. The 2009 Load Forecast follows the same methodology as the 2008 Load Forecast presented in the 2008 LTAP. Before DSM, the 2009 Load Forecast is lower than the 2008 Load Forecast in the early years primarily due to lower transmission and general service customer sales forecasts. For example, the 2009 Load Forecast is down 214 GWh/year in F2017 when compared to the 2008 Load Forecast. However, stronger expectations for future oil and gas activity and new mining loads drives the 2009 Load forecast higher in the later years;
- DSM is based on the DSM Plan as set out in the 2008 LTAP Evidentiary Update.[10] In the 2008 LTAP, BC Hydro concluded that the DSM Plan included all the DSM that it could cost-effectively plan to acquire at this time;
- Burrard's firm energy contribution is zero as a result of Direction No. 2 to the BCUC;
- The Waneta Transaction's contribution of 865 GWh/year of firm energy is included;[11]
- The 2,500 GWh/year of non-firm energy/market allowance is included up to December 31, 2015; thereafter, such energy supply is not used for planning purposes in order to achieve self-sufficiency by 2016 and beyond; and
- None of the 3,000 GWh/year insurance called for in the 2007 Energy Plan or subsection 6(2)(b) of the *Clean Energy Act* is included. If the insurance requirement is added to the load/resource balance figures, the energy gap would increase considerably by F2021, or sooner if the additional 3,000 GWh is acquired on a phased basis.

BC Hydro's Current Power Acquisition Processes

BC Hydro has two other power acquisition processes underway – the Bioenergy Phase 2 Call and the Integrated Power Offer (IPO).

The Bioenergy Phase 2 Call is a competitive RFP for larger-scale biomass projects. Any form of biomass will be eligible, including wood waste sourced from new forest tenure enabled through sections 13 to 36 of the *Emissions Standards Act* enacted in May 2008. The RFP for the Bioenergy Phase 2 Call was issued on May 31, 2010. The target is to acquire up to 1,000 GWh/year (pre-attrition) or 700 GWh/year (post-attrition using a 30 percent attrition factor) of cost-effective energy.

BC Hydro launched the IPO for those pulp and paper customers eligible for funding under the Federal Government's $1 billion Pulp and Paper Green Transformation Program (GTP) which was introduced in June 2009. The GTP supports innovation and investment in areas such as energy efficiency and renewable energy production technologies. BC Hydro is taking an "integrated offer" approach with its eight pulp and paper customers which are eligible for GTP funding. The IPO will capitalize on the synergies presented when energy efficiency savings and electricity generation opportunities are considered together. BC Hydro estimates that the IPO will result in approximately 1,200 GWh/year (pre-attrition) or about 1,080 GWh/year (post-attrition using a 10 per cent attrition factor) of cost-effective energy.

Energy Load/Resource Balance with Bioenergy Phase 2 Call and IPO Projects

Table 5-2 shows the energy load/resource balance taking into account the estimated Bioenergy Phase 2 Call and IPO initiatives. Even with the addition of these resources, there is a gap of approximately 2,300 GWh/year (without insurance) in F2017. The 3,266 GWh/year of firm energy being purchased under the Clean Power Call equates to 2,286 GWh/year on a post-attrition basis assuming a 30 per cent attrition factor. Thus, the Clean Power Call EPA awards will allow BC Hydro to be largely in energy balance in F2017, effectively achieving self-sufficiency by calendar 2016.

Table 5-2: Energy Load/Resource Balance after Bioenergy Phase 2 Call and IPO

(GWh/year)	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020
Energy Gap	200	200	100	-100	-2300	-3000	-3600	-3700

As shown in Table 5-2, there is a need for energy from the Clean Power Call as well as the Bioenergy Phase 2 Call and the IPO. Furthermore, there is still an energy shortfall of 700 to 1,400 GWh during F2018-20 which will be exacerbated with the need to acquire insurance volumes on or before the mandated 2020 timeframe.

---

[8] See, for example, the Western Climate Initiative's position set out in "*Electricity Subcommittee Discussion Paper on Renewable Portfolio Standards, Renewable Energy Credits and GHG Accounting*" (8 December 2008), page 1.

[9] See, for example, Ontario's Feed-In Tariff Program, enacted under the Ontario *Green Energy and Green Economy Act, 2009*, pursuant to which IPPs must transfer environmental attributes arising from projects to the purchasing entity, the Ontario Power Authority.

[10] Exhibit B-10 in the 2008 LTAP BCUC proceeding; annual values for energy are set out in Table 2-10 of the 2008 LTAP Evidentiary Update. The DSM numbers have been adjusted for base year savings achieved for the first 10 years (F2010 to F2019).

[11] Pursuant to BCUC Order G-12-10, dated 3 February 2010.

6. COST-EFFECTIVENESS

As identified in previous sections of this Report: (1) BC Hydro has a requirement for firm supply throughout its planning horizon and (2) the B.C. Government has placed significant importance, at a policy level, on acquisition of clean, renewable electricity. No comparisons are made with electricity that may be available in external power markets such as Mid-Columbia since post-2015 the BCUC is precluded from permitting BC Hydro to rely on such electricity sources pursuant to Special Direction 10.

a) Competitive Process

BC Hydro relies on the competitive Clean Power Call process as the primary support for its position that the EPAs are cost-effective. The BCUC previously found that an important determination of cost-effectiveness is whether or not the particular power acquisition process awards were the outcome of a competitive process that yielded a cost-effective result. In its Decision on the Call for Tenders for Capacity on Vancouver Island,[12] the BCUC stated:

> … once a competitive market-based process has been undertaken and firm commitments from bidders have been obtained, a competitive process should, in most circumstances, be accepted as persuasive evidence of the cost-effectiveness of the resultant successful bid.

BC Hydro notes that the volume of EPA awards – at 3,266 GWh/year – represents an acquisition of less than 20 per cent of the energy that was presented in proposals received. The following facts support BC Hydro's view that the Clean Power Call was a competitive, fair and transparent process:

- **Participation** – This was at a high level. As described in Section 3 of this Report, in November 2008 BC Hydro received 68 proposals from 43 proponents, representing more than 17,000 GWh/year of firm energy. Many of the participants were well-established industrial firms in B.C. and/or well-established and qualified IPPs.

- **Terms and Conditions Review** – In designing the Clean Power Call, BC Hydro sought First Nations, government agency, financial advisor, proponent and other stakeholder input to ensure the terms would not unduly discourage participation while at the same time providing adequate assurance to BC Hydro and its ratepayers regarding delivery commitments. BC Hydro is of the view that potential proponents and other stakeholders had ample opportunity to comment not only on the proposed process but also on the draft documentation (see Section 4 of the Report). Furthermore, BC Hydro retained Deloitte & Touche LLP to conduct a term sheet review in spring 2008 which identified potential issues and opportunities related to pricing and value-for-money.

- **RFP Process** – The RFP offered contract term and COD flexibility (both initial COD and the opportunity for phased COD) and hourly and seasonally firm energy options. In addition to the options set out in the RFP documents, proponents were allowed to propose variations to the Specimen EPA included in their contract price (an essential variation) or as an option that BC Hydro could chose to incorporate if it had value (a value variation). BC Hydro utilized the discretion inherent in an RFP process to negotiate price as well as both essential variations and value variations with proponents. In addition, BC Hydro could and did propose variations to the proposals that increased their value to BC Hydro and ratepayers.

- **Least Cost** – The awarded EPAs were among the least cost of the proposals and were considered to be cost-effective.

- **Consistency with Expectations** – The cost of the electricity acquired from the EPAs is in line with BC Hydro's expectations. BC Hydro estimated the cost of new long-term firm energy supply in the 2008 LTAP proceeding as $124/MWh in 2008 constant dollars (or $129/MWh in 2010 dollars using 2.1 per cent CPI escalation). This estimate represents the average real levelized cost to deliver firm energy to the load centre in the Lower Mainland including: (a) adjusters for transmission infrastructure costs and losses; (b) a capacity credit for resources that could provide an hourly firm energy product; (c) a relative valuation of energy acquired at different times of the year.

b) Comparison to Other Processes

In addition to its reliance on the competitiveness and transparency of the acquisition process, BC Hydro compared the awarded EPAs with the following:

- The unsuccessful Bioenergy Phase 1 RFP bidders;
- The clean, renewable power acquisition processes of other jurisdictions in North America;
- The Unit Energy Cost (UEC) data from the 2008 LTAP Resource Options Update for a 250 MW CCGT.

BC Hydro submits that these comparisons further indicate that the Clean Power Call EPAs are cost-effective.

Comparison to Bioenergy Call Phase 1 RFP

The levelized adjusted bid prices for the 14 unsuccessful Phase 1 RFP bidders range from $119/MWh to $395/MWh (see Table 6-1).

Given that the project submitted by the lowest cost unsuccessful proponent was assessed as having an overly high risk of not being developed, the relevant price range for the comparison of the EPA awards is $136/MWh to $395/MWh. All of the awarded Clean Power Call EPAs are below the price range offered by unsuccessful Bioenergy Phase 1 RFP bidders.

Table 6-1: Bioenergy Phase 1 RFP – Unsuccessful Proposals

Proposal	Offered Firm Energy Price at Plant Gate ($/MWh)	Levelized Plant Gate Price ($/MWh)	Levelized Adjusted Bid Price ($/MWh)
C	112	111	119
G	135	134	136
H	137	127	139
I	138	151	149
J	144	147	162
K	158	171	178
L	169	185	192
M	150	183	193
N	201	187	205
O	175	193	208
P	179	200	214
Q	182	203	217
R	195	230	252
S	194	217	328
T	300	365	395

Comparison with Other Jurisdictions

Many jurisdictions in the U.S. and Canada carry out acquisition processes for green or renewable power. Table 6-2 summarizes comparable renewable power acquisition processes in North America that have been either completed or launched since 2007.

The levelized energy prices for comparable calls in other jurisdictions vary from $79 to $176 per MWh (Canadian 2009$). As shown in Table 3-4, the levelized energy price for the Clean Power Call EPAs is $101/MWh for total energy and $111/MWh for firm energy at the plant gate level. Given that these prices are at the lower end of the energy price range for other North American jurisdictions, BC Hydro is of the view that the awarded Clean Power Call EPAs are cost-effective.

Comparison with New Generic CCGT

In the 2008 LTAP, BC Hydro committed to comparing Clean Power Call EPA awards to a generic, green field 250 MW CCGT located in the Kelly Lake/Nicola region in the B.C. interior, adjusted for location and the requirement to completely offset all GHG emissions by the CCGT COD.[13] The average energy from a 250 MW CCGT would be 1,916 GWh/year assuming a 90 per cent capacity factor.

If BC Hydro were to acquire electricity from CCGTs sited in Kelly Lake, it would have to be supplied by IPPs to meet the requirements of Policy Action No. 13 of the 2002 Energy Plan.

Table 6-3 sets out the UEC of the generic 250 MW CCGT at a 6 per cent real discount rate, delivered to the Lower Mainland. BC Hydro notes the following:

- Cost Information – In contrast to the bidding price information upon which the Clean Power Call EPAs are based, the analysis set out below is based on the 2008 LTAP Resource Options Report, with a planning level cost estimate based on a cost uncertainty of +40/-10 per cent. There is thus less cost certainty with the 250 MW generic CCGT when compared to the EPAs.

Table 6-2: Comparison to Other Renewable Power Acquisition Processes

	Award or Launch Date	Target Size of Call	Stated Energy Price* ($/MWh)	Energy Price – Levelized** (2009Cdn.$/MWh)
Hydro-Quebec 2005 Wind-Generated Electricity CFT (awards)	May 2008	2,000 MW	$87	$93
Puget Sound Energy 2008 All-Source RFP (bids received)	July 2008	2,235 MW	Hydro: US$79–164 Wind: US$104–155	Hydro: $85–176 Wind: $112–166
Portland General Electric 2007 Renewables RFP (shortlisted bids – mostly wind)	December 2008	255 MW	US$85–110	$91–118
Ontario Power Authority Feed-In Tariff	March 2009	Open offer	Hydro: $122–131 Wind: $135–190	Hydro: $85–111 Wind: $115–163
Hydro-Quebec Wind CFT for Aboriginal and Community Projects	April 2009	500 MW	$125 ceiling	$125

* Stated prices are typically for total energy and reflect contractual plant gate levels.

** Assume Canadian dollar = $0.95 U.S. and annual inflation of 2 per cent.

- Variable Cost Uncertainties – There are significant variable cost uncertainties with respect to CCGTs when compared to clean, renewable resources such as the Clean Power Call EPAs:

  - Table 6-3 shows a number of natural gas and GHG price forecast combinations, ranging from High/High to Low/Low. This highlights the fact that there is significant natural gas and GHG price uncertainty associated with a CCGT when compared to clean, renewable resources such as the EPAs.

  - Natural Gas Price Forecast – BC Hydro retained the independent expert Black & Veatch (B&V) to re-weight the 2008 Natural Gas Price Forecast set out in the 2008 LTAP based on new developments such as shale gas potential. B&V re-weighted the forecast as follows: (1) High – now at 11% (was 53%); Medium – now at 43% (was 44%) and Low – now at 46% (was 2%).

  - GHG Price Forecast – BC Hydro continues to rely on the GHG price forecast set out in the 2008 LTAP, which results from an independent expert (Natsource LLP) and was accepted by the BCUC in the 2008 LTAP Decision.[14] The three GHG scenarios are as follows: (1) lowest cost Price Cap scenario (15 per cent probability); (2) mid cost Linked Markets scenario (60 per cent probability); and (3) highest cost Made in North America Aggressive scenario (25 per cent probability).

  - The result is that a CCGT at the weighted average natural gas price and GHG price scenario is about $98/MWh, compared to a previous weighted average natural gas price and mid GHG price scenario of about $118/MWh.

  - Contracting Uncertainties – BC Hydro also notes that there would be contracting uncertainties related to allocating the risks that exist with CCGTs.

  - Other Risks – Uncertainties associated with renewable energy credits, offsets and other mechanisms which are required to render CCGTs as green projects.

- No Environmental Attributes – The Clean Power Call EPAs provide value-added Environmental Attributes which are not available from CCGT resources.

In addition to the cost and contractual uncertainties set out above, in BC Hydro's view, a CCGT has limited relevance as a price benchmark, for the following reasons:

- The BCUC endorsed a clean, renewable call as part of the 2008 LTAP Decision. In BC Hydro's view, this means that CCGTs are not truly alternatives to the EPAs. BC Hydro placed far more weight on the clean, renewable price benchmarks set out above.

- There is significant B.C. Government policy uncertainty with respect to the role of natural gas as a fuel for electricity generation, particularly with respect to BC Hydro's integrated electricity system. Legal and policy decisions made by the B.C. Government cast doubt on the acceptability of new natural gas-fired generation as part of the BC Hydro integrated system.

Even if the B.C. Government supports BC Hydro acquiring electricity from CCGTs, there is significant development risk. A 250 MW CCGT would trigger the B.C. *Environmental Assessment Act* and an air emission permit pursuant to the B.C. *Environmental Management Act*, with the public being involved pursuant to the Public Notification Regulation. Emission of pollutants such as nitrogen oxides, sulphur dioxide and carbon monoxide would be examined, in addition to GHG emissions and provisions for offsetting the GHG emissions. Although GHG emissions are a global as opposed to local impact issue, BC Hydro's experience has been that local residents are sceptical of the argument that a GHG offset located outside the region or indeed outside B.C. is as effective in reducing GHG emissions.

Details of the 27 Clean Power Call projects selected for the award of electricity purchase agreements are available on BC Hydro's website at **www.bchydro.com/cleanpowercall**.

Table 6-3: Unit Energy Cost for Generic 250 MW CCGT

	High Gas High GHG	High Gas Mid GHG	Mid Gas High GHG	Mid Gas Mid GHG	Low Gas Low GHG	Weighted Avg. Gas Weighted Avg. GHG
UEC contribution from capital + OMA	$ 21.14	$ 21.14	$ 21.14	$ 21.14	$ 21.14	$ 21.14
UEC contribution from fuel	$ 93.27	$ 93.27	$ 59.07	$ 59.06	$ 48.52	$ 57.98
UEC contribution from GHG	$ 19.65	$ 11.53	$ 19.65	$ 11.53	$ 8.22	$ 13.07
UEC (equivalent to FEP)	$ 134.06	$ 125.95	$ 99.85	$ 91.74	$ 77.89	$ 92.18
CIFT adjuster	$ 1.95	$ 1.95	$ 1.95	$ 1.95	$ 1.95	$ 1.95
Loss adjuster	$ 5.27	$ 4.96	$ 3.94	$ 3.63	$ 3.09	$ 3.65
Lower Mainland hourly firm energy adjuster	$ (3.88)	$ (3.88)	$ (3.88)	$ (3.88)	$ (3.88)	$ (3.88)
Levelized AFEP	$ 137.40	$ 128.98	$ 101.87	$ 93.44	$ 79.06	$ 93.90
Levelized AFEP in 2010 $/MWh	$ 143.23	$ 134.45	$ 106.19	$ 97.41	$ 82.41	$ 97.89

[12] BCUC Order No. E-1-05, page 13
[13] 2008 LTAP, page 6-45, lines 10-16, Exhibit B-1 in the 2008 LTAP proceeding.
[14] *Supra*, note 1, page 29.

Appendix A

Summary Listing of Clean Power Call EPA Awards

Proponent Name	Project Name	Location	Region	Energy Source	Capacity [MW]	Firm Energy [GWh/year]
AltaGas Ltd.	Crowsnest Pass	Sparwood	East Kootenay	waste heat	11	46
Box Canyon Hydro Corporation and Sound Energy Inc.	Box Canyon	Port Mellon	Lower Mainland	run-of-river	15	50
Castle Mountain Hydro Ltd	Benjamin Creek	McBride	Kelly Nicola	run-of-river	6	27
C-Free Power Corp.	Jamie Creek	Gold Bridge	Kelly Nicola	run-of-river	19	41
Cloudworks Energy Inc.	Big Silver-Shovel Creek	Harrison Hot Springs	Lower Mainland	run-of-river	37	110
Cloudworks Energy Inc.	Northwest Stave River	Mission	Lower Mainland	run-of-river	18	44
Cloudworks Energy Inc.	Tretheway Creek	Mission	Lower Mainland	run-of-river	21	56
CP Renewable Energy (B.C.) Limited Partnership (formerly EPCOR)	Quality Wind	Tumbler Ridge	Peace River	wind	142	434
Creek Power Inc.	Boulder Creek	Pemberton	Lower Mainland	run-of-river	23	48
Creek Power Inc.	North Creek	Pemberton	Lower Mainland	run-of-river	16	34
Creek Power Inc.	Upper Lillooet	Pemberton	Lower Mainland	run-of-river	74	143
ENMAX - Syntaris Bid Corp.	Culliton Creek	Squamish	Lower Mainland	run-of-river	15	56
Finavera Renewables Inc.	Bullmoose	Tumbler Ridge	Peace River	wind	60	142
Finavera Renewables Inc.	Meikle	Tumbler Ridge	Peace River	wind	117	327
Finavera Renewables Inc.	Tumbler Ridge	Tumbler Ridge	Peace River	wind	45	140
Finavera Renewables Inc.	Wildmare	Chetwynd	Peace River	wind	71	204
Pacific Greengen Power	Bremner / Trio	Harrison Hot Springs	Lower Mainland	run-of-river	45	148
Kwagis Power Limited Partnership	Kokish River	Port McNeill	Vancouver Island	run-of-river	45	183
Long Lake Joint Venture	Long Lake	Stewart	North Coast	storage hydro	31	139
NI Hydro Holding Corp. (representing Stlixwim entities)	Ramona 3 + Chickwat Creek + CC Creek	Sechelt	Lower Mainland	run-of-river	45	198
Plutonic Power Corporation and GE Energy Financial Services Co.	Upper Toba Valley	Powell River	Lower Mainland	run-of-river	124	214
Run of River Power Inc.	Mamquam	Squamish	Lower Mainland	run-of-river	25	68
Sea Breeze Energy Inc.	Knob Hill Wind	Port Hardy	Vancouver Island	wind	99	281
Selkirk Power Company Ltd.	Beaver River	Golden	East Kootenay	run-of-river	44	86
Swift Power Corp.	Dasque-Middle	Terrace	North Coast	run-of-river	20	46
Total					1,168	3,266

Appendix B

Dated: June 7, 2010

INDEPENDENT OBSERVER'S REPORT
ON BC HYDRO CLEAN POWER CALL

I was invited in October of 2008 to respond to a Request for Proposals from BC Hydro to act as an Independent Observer for BC Hydro's Clean Power Call. My proposal was accepted by BC Hydro and I have been performing the services of a Fairness Monitor / Independent Observer to the Clean Power Call from November of 2008 to the present time.

In my role as Independent Observer / Fairness Monitor I have reviewed in detail the Request for Proposals issued on June 11, 2008 and numerous other documents related to the RFP. Additionally, I have received and reviewed documentation exchanged between various proponents and BC Hydro during the process of evaluation of the various proposals received, and I have attended numerous meetings with representatives of Hydro alone and with representatives of Hydro and representatives of proponents on various occasions to monitor the evaluation process and, where applicable, report on and assist in the resolution of potential fairness issues.

At the outset of the Clean Power Call process, certain "listed" proponents were identified, being those proponents who had on their team individuals with previous significant relationships with BC Hydro. The evaluation of these proponents was monitored particularly closely. I was given access to all documentation relating to each of these proponents and attended most meetings held between these proponents and representatives of BC Hydro during the evaluation process.

During the course of the foregoing activities, my role was to observe the process during the course of meetings and in the exchange of correspondence to assure as far as practicably possible that the guidelines and terms and conditions set out in the RFP were followed and applied equally and fairly in the case of all proponents, and particularly in the case of the listed proponents. My involvement in this regard has included being kept fully informed of the evaluation of those proposals which have resulted in or are likely to result in the award of energy purchase agreements.

In the result, I have observed a very comprehensive and robust process in the receiving, assessment, and evaluation of the proposals received in response to the Clean Power Call and, in my opinion, the process has been fair, transparent and without any demonstrated bias being shown towards any particular proponent. Additionally, I have observed a keen awareness and commitment by those responsible for administering the process and evaluating the proposals to the requirements of the RFP and the Evaluation Guidelines and generally to the need to bring fairness to the process at all levels.

RESPECTFULLY SUBMITTED,

John R. Singleton, Q.C.

GENERAL/50238.345/725122.1

Appendix 3

MODIFIED TRC TEST RESULTS
FEU EXISTING PROGRAM AREAS

Indicator		Service Territory		Total
		FEI	FEVI	
Annual Gas Savings, Gross (GJ/yr.)	2012	849,976	85,764	935,740
	2013	1,845,472	166,162	2,011,634
NPV of Gas Savings, Gross (GJ)		14,305,228	1,325,457	15,630,685
Annual Gas Savings, Net (GJ/yr.)	2012	746,255	77,378	823,633
	2013	1,654,107	156,707	1,810,815
NPV of Gas Savings, Net (GJ)		12,697,664	1,296,486	13,994,150
Utility Expenditures, Incentives ($1000s)	2012	22,174	3,439	25,614
	2013	22,174	3,447	25,621
	Total	44,348	6,886	51,234
Utility Expenditures, Non-Incentives ($1000s)	2012	11,127	1,536	12,662
	2013	11,021	1,541	12,563
	Total	22,148	3,077	25,225
Utility Expenditures, Total ($1000s)	2012	33,301	4,975	38,276
	2013	33,195	4,988	38,183
	Total	66,496	9,963	76,459
Cost of Saved Energy ($/GJ)	2012	44.62	64.29	46.47
	Levelized	5.09	8.94	5.46
Benefit/Cost Ratios	TRC	1.28	1.27	1.27
	MTRC*	2.88	2.70	2.86
	Utility	2.06	1.35	1.95
	Participant	2.46	2.52	2.47
	RIM	0.59	0.53	0.58
	Societal	3.12	2.59	3.05

Note: Whistler (FEW) is included in the FEI service territory

* The portfolio level MTRC does not include High Carbon Fuel Switching programs

Portfolio and Service Territory	Annual Gas Savings, Gross (GJ/yr.)		NPV Gas Savings, Gross (GJ)	Annual Gas Savings, Net (GJ/yr.)		NPV Gas Savings, Net (GJ)	Utility Expenditures ($1000s)									Cost of Saved Energy ($/GJ)		Benefit/Cost Ratios					
							Incentives			Non-Incentives			All Spending					TRC	MTRC*	Utility	Participant	RIM	Societal
	2012	2013		2012	2013		2012	2013	Total	2012	2013	Total	2012	2013	Total	2012	Levelized						
Residential Sector																							
FEI	178,683	417,322	3,301,992	154,366	371,099	2,827,053	5,613	5,224	10,838	2,794	3,263	6,057	8,407	8,487	16,895	54.46	5.77	0.92	2.07	1.86	1.71	0.56	2.35
FEVI	22,363	42,369	448,891	18,908	36,025	382,219	809	718	1,527	298	279	577	1,107	997	2,104	58.56	5.34	0.92	2.07	2.03	2.15	0.45	2.28
Total	201,045	459,691	3,750,883	173,274	407,124	3,209,271	6,422	5,942	12,365	3,092	3,542	6,634	9,514	9,484	18,999	54.91	5.74	0.92	2.07	1.88	1.76	0.55	2.34
High Carbon Fuel Switching																							
FEI	-4,300	-8,600	-87,292	-2,150	-4,300	-43,646	100	100	200	26	26	52	126	126	252	-58.60	-16.32	1.67		0.00	1.73	0.91	1.71
FEVI	-17,200	-34,400	-361,302	-8,600	-17,200	-180,651	400	400	800	104	104	208	504	504	1,008	-58.60	-16.16	1.68		0.00	1.28	1.04	1.71
Total	-21,500	-43,000	-448,593	-10,750	-21,500	-224,297	500	500	1,000	130	130	260	630	630	1,260	-58.60	-16.64	1.68		0.00	1.35	1.02	1.71
Low Income																							
FEI	27,169	54,338	393,473	22,825	45,649	337,980	2,752	2,752	5,504	1,698	1,698	3,395	4,450	4,450	8,899	194.95	25.43	0.54	1.06	0.40	1.96	0.27	1.00
FEVI	3,019	6,038	44,708	2,536	5,072	38,425	306	306	612	214	214	427	519	519	1,039	204.77	26.16	0.52	1.03	0.39	2.34	0.24	0.95
Total	30,188	60,376	438,181	25,361	50,721	376,405	3,058	3,058	6,116	1,911	1,911	3,822	4,969	4,969	9,938	195.93	25.56	0.54	1.06	0.40	2.00	0.27	0.99
Commercial Sector																							
FEI	447,358	887,671	7,004,449	388,295	788,909	6,191,933	10,824	11,388	22,212	1,713	1,135	2,848	12,537	12,523	25,060	32.29	3.91	1.44	3.34	2.67	2.59	0.61	3.60
FEVI	76,466	135,699	1,079,518	63,418	116,354	942,851	1,834	1,801	3,635	149	176	325	1,983	1,977	3,960	31.27	4.07	1.71	3.98	2.58	4.20	0.44	4.15
Total	523,824	1,023,370	8,083,967	451,713	905,263	7,134,784	12,658	13,189	25,847	1,861	1,312	3,173	14,520	14,500	29,020	32.14	3.94	1.47	3.41	2.66	2.78	0.58	3.67
Conservation, Education, and Outreach																							
FEI	0	0	0	0	0	0	0	0	0	4,281	4,284	8,564	4,281	4,284	8,564			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	720	717	1,436	720	717	1,436			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	5,000	5,000	10,000	5,000	5,000	10,000			0.00	0.00	0.00		0.00	0.00
Industrial Sector																							
FEI	172,758	402,486	2,879,123	155,482	362,237	2,591,211	1,840	1,840	3,679	258	258	516	2,098	2,098	4,195	13.49	1.56	3.73	8.44	6.49	5.34	0.78	9.00
Innovative Technologies																							
FEI	19,598	74,835	610,000	19,598	74,835	610,000	1,046	870	1,916	358	358	716	1,404	1,228	2,632	71.62	4.18	1.81	3.68	2.57	2.79	0.78	4.25
FEVI	1,116	16,456	113,641	1,116	16,456	113,641	90	222	312	52	52	104	142	274	416	127.24	3.51	2.00	4.05	2.96	4.19	0.55	4.38
Total	20,714	91,291	723,641	20,714	91,291	723,641	1,136	1,092	2,228	410	410	820	1,546	1,502	3,048	74.62	4.09	1.84	3.73	2.62	2.99	0.73	4.27
ALL PORTFOLIOS																							
FEI	849,976	1,845,472	14,305,228	746,255	1,654,107	12,697,664	22,174	22,174	44,348	11,127	11,021	22,148	33,301	33,195	66,496	44.62	5.09	1.28	2.88	2.06	2.46	0.59	3.12
FEVI	85,764	166,162	1,325,457	77,378	156,707	1,296,486	3,439	3,447	6,886	1,536	1,541	3,077	4,975	4,988	9,963	64.29	8.94	1.27	2.70	1.35	2.52	0.53	2.59
Total	935,740	2,011,634	15,630,685	823,633	1,810,815	13,994,150	25,614	25,621	51,234	12,662	12,563	25,225	38,276	38,183	76,459	46.47	5.46	1.27	2.86	1.95	2.47	0.58	3.05

Note: Whistler (FEW) is included in the FEI service territory

Program and Service Territory	Annual Gas Savings, Gross (GJ/yr.)		NPV Gas Savings, Gross (GJ)	Annual Gas Savings, Net (GJ/yr.)		NPV Gas Savings, Net (GJ)	Utility Expenditures ($1000s)									Cost of Saved Energy ($/GJ)		Benefit/Cost Ratios					
							Incentives			Non-Incentives			All Spending					TRC	MTRC	Utility	Participant	RIM	Societal
	2012	2013		2012	2013		2012	2013	Total	2012	2013	Total	2012	2013	Total	2012	Levelized						
ENERGY STAR® Domestic Hot Water “DHW” Technologies																							
FEI	20,250	40,500	394,677	18,225	36,450	355,209	1,215	1,215	2,430	393	393	785	1,608	1,608	3,215	88.20	8.74	0.50	1.13	1.22	1.03	0.50	1.27
FEVI	2,250	4,500	45,327	2,025	4,050	40,795	135	135	270	44	44	87	179	179	357	88.15	8.47	0.52	1.17	1.26	1.33	0.41	1.27
Total	22,500	45,000	440,004	20,250	40,500	396,004	1,350	1,350	2,700	436	436	872	1,786	1,786	3,572	88.20	8.71	0.50	1.13	1.23	1.06	0.49	1.27
EnerChoice Fireplace Program																							
FEI	22,599	35,154	327,467	17,175	26,717	248,875	875	486	1,361	347	266	612	1,221	752	1,973	71.11	7.72	2.37	5.39	1.36	8.69	0.52	5.87
FEVI	5,301	8,246	79,069	4,029	6,267	60,092	205	114	319	82	63	144	287	177	463	71.16	7.52	2.44	5.54	1.39	11.39	0.42	5.86
Total	27,900	43,400	406,535	21,204	32,984	308,967	1,080	600	1,680	428	328	756	1,508	928	2,436	71.11	7.70	2.38	5.40	1.36	8.96	0.51	5.87
“Give your Furnace/Fireplace Some TLC” – Service Campaign																							
FEI	0	0	0	0	0	0	394	394	788	169	169	338	563	563	1,126			0.00	0.00	0.00	0.17	0.00	0.00
FEVI	0	0	0	0	0	0	44	44	88	19	19	38	63	63	126			0.00	0.00	0.00	0.17	0.00	0.00
Total	0	0	0	0	0	0	438	438	875	188	188	376	626	626	1,251			0.00	0.00	0.00	0.17	0.00	0.00
Energy Efficient Home Retrofit Programs																							
FEI	84,240	168,480	1,797,316	69,077	138,154	1,473,799	2,147	2,147	4,293	576	576	1,152	2,723	2,723	5,445	39.41	3.57	1.62	3.67	3.05	2.88	0.64	4.21
FEVI	9,360	18,720	207,221	7,675	15,350	169,921	239	239	477	64	64	128	303	303	605	39.41	3.45	1.68	3.82	3.17	3.85	0.49	4.21
Total	93,600	187,200	2,004,538	76,752	153,504	1,643,721	2,385	2,385	4,770	640	640	1,280	3,025	3,025	6,050	39.41	3.56	1.62	3.68	3.06	2.97	0.62	4.21
Home Energy Efficiency Web Portal																							
FEI	0	0	0	0	0	0	0	0	0	90	90	180	90	90	180			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	10	10	20	10	10	20			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	100	100	200	100	100	200			0.00	0.00	0.00		0.00	0.00
ENERGY STAR® Washers and Other Measures for DHW Conservation																							
FEI	22,950	45,900	406,907	21,803	43,605	386,562	383	383	765	90	90	180	473	473	945	21.67	2.36	0.94	2.03	4.42	1.44	0.69	2.25
FEVI	2,550	5,100	46,496	2,423	4,845	44,171	43	43	85	10	10	20	53	53	105	21.67	2.30	0.96	2.09	4.54	1.90	0.53	2.25
Total	25,500	51,000	453,403	24,225	48,450	430,733	425	425	850	100	100	200	525	525	1,050	21.67	2.35	0.94	2.03	4.44	1.49	0.68	2.25
Customer Engagement Tool for Conservation Behaviours*																							
FEI	17,500	105,000	115,284	17,500	105,000	115,284	0	0	0	500	1,050	1,550	500	1,050	1,550	28.57	12.82	0.69	1.67	0.69		0.37	1.58
New Construction – EGH 80 & Beyond and EE Appliances																							
FEI	11,144	22,288	260,341	10,587	21,173	247,324	601	601	1,201	180	180	360	781	781	1,561	73.74	6.10	0.44	1.00	1.84	0.90	0.52	1.20
FEVI	2,902	5,803	70,778	2,757	5,513	67,239	144	144	288	20	20	40	164	164	328	59.58	4.73	0.48	1.09	2.38	1.14	0.45	1.25
Total	14,045	28,091	331,119	13,343	26,686	314,563	745	745	1,490	200	200	400	945	945	1,890	72.33	5.96	0.45	1.01	1.89	0.92	0.52	1.20
Efficiency Partners Program																							
FEI	0	0	0	0	0	0	0	0	0	450	450	900	450	450	900			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	50	50	100	50	50	100			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	500	500	1,000	500	500	1,000			0.00	0.00	0.00		0.00	0.00
ALL PROGRAMS																							
FEI	**178,683**	**417,322**	**3,301,992**	**154,366**	**371,099**	**2,827,053**	**5,613**	**5,224**	**10,838**	**2,794**	**3,263**	**6,057**	**8,407**	**8,487**	**16,895**	**54.46**	**5.77**	**0.92**	**2.07**	**1.86**	**1.71**	**0.56**	**2.35**
FEVI	**22,363**	**42,369**	**448,891**	**18,908**	**36,025**	**382,219**	**809**	**718**	**1,527**	**298**	**279**	**577**	**1,107**	**997**	**2,104**	**58.56**	**5.34**	**0.92**	**2.07**	**2.03**	**2.15**	**0.45**	**2.28**
Total	**201,045**	**459,691**	**3,750,883**	**173,274**	**407,124**	**3,209,271**	**6,422**	**5,942**	**12,365**	**3,092**	**3,542**	**6,634**	**9,514**	**9,484**	**18,999**	**54.87**	**5.74**	**0.92**	**2.07**	**1.88**	**1.76**	**0.55**	**2.34**

Note: Whistler (FEW) is included in the FEI service territory

* Measure lifetime of 1 year used for all calculations, as opposed to the 2 year measure lifetime that was assumed in the original submission

Program and Service Territory	Annual Gas Savings, Gross (GJ/yr.)		NPV Gas Savings, Gross (GJ)	Annual Gas Savings, Net (GJ/yr.)		NPV Gas Savings, Net (GJ)	Utility Expenditures ($1000s)									Cost of Saved Energy ($/GJ)		Benefit/Cost Ratios					
							Incentives			Non-Incentives			All Spending										
	2012	2013		2012	2013		2012	2013	Total	2012	2013	Total	2012	2013	Total	2012	Levelized	TRC	MTRC	Utility	Participant	RIM	Societal
Switch N Shrink																							
FEI	-4,300	-8,600	-87,292	-2,150	-4,300	-43,646	100	100	200	26	26	52	126	126	252	-58.60	-16.32	1.67		0.00	1.73	0.91	1.71
FEVI	-17,200	-34,400	-361,302	-8,600	-17,200	-180,651	400	400	800	104	104	208	504	504	1,008	-58.60	-16.16	1.68		0.00	1.28	1.04	1.71
Total	-21,500	-43,000	-448,593	-10,750	-21,500	-224,297	500	500	1,000	130	130	260	630	630	1,260	-58.60	-16.64	1.68		0.00	1.35	1.02	1.71
ALL PROGRAMS																							
FEI	**-4,300**	**-8,600**	**-87,292**	**-2,150**	**-4,300**	**-43,646**	**100**	**100**	**200**	**26**	**26**	**52**	**126**	**126**	**252**	**-58.60**	**-16.32**	**1.67**		**0.00**	**1.73**	**0.91**	**1.71**
FEVI	**-17,200**	**-34,400**	**-361,302**	**-8,600**	**-17,200**	**-180,651**	**400**	**400**	**800**	**104**	**104**	**208**	**504**	**504**	**1,008**	**-58.60**	**-16.16**	**1.68**		**0.00**	**1.28**	**1.04**	**1.71**
Total	**-21,500**	**-43,000**	**-448,593**	**-10,750**	**-21,500**	**-224,297**	**500**	**500**	**1,000**	**130**	**130**	**260**	**630**	**630**	**1,260**	**-58.60**	**-16.64**	**1.68**		**0.00**	**1.35**	**1.02**	**1.71**

Note: Whistler (FEW) is included in the FEI service territory

Program and Service Territory	Annual Gas Savings, Gross (GJ/yr.)		NPV Gas Savings, Gross (GJ)	Annual Gas Savings, Net (GJ/yr.)		NPV Gas Savings, Net (GJ)	Utility Expenditures ($1000s)									Cost of Saved Energy ($/GJ)		Benefit/Cost Ratios					
							Incentives			Non-Incentives			All Spending										
	2012	2013		2012	2013		2012	2013	Total	2012	2013	Total	2012	2013	Total	2012	Levelized	TRC	MTRC	Utility	Participant	RIM	Societal
Residential Energy Efficiency Works (REnEW)																							
FEI	0	0	0	0	0	0	0	0	0	145	145	290	145	145	290			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	40	40	80	40	40	80			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	185	185	370	185	185	370			0.00	0.00	0.00		0.00	0.00
Energy Saving Kit (ESK)																							
FEI	14,164	28,328	172,845	10,340	20,680	126,177	165	165	329	135	135	270	300	300	599	28.98	4.59	3.29	6.54	2.16	7.80	0.60	5.92
FEVI	1,574	3,148	19,539	1,149	2,298	14,264	18	18	37	16	16	32	34	34	69	29.86	4.65	3.22	6.42	2.13	10.54	0.46	5.71
Total	15,738	31,476	192,385	11,489	22,977	140,441	183	183	366	151	151	302	334	334	668	29.07	4.59	3.28	6.52	2.16	8.07	0.58	5.90
Energy Conservation Assistance Program (ECAP)																							
FEI	13,005	26,010	220,628	12,485	24,970	211,803	2,588	2,588	5,175	1,418	1,418	2,835	4,005	4,005	8,010	320.79	36.52	0.38	0.75	0.28	1.59	0.21	0.71
FEVI	1,445	2,890	25,168	1,387	2,774	24,162	288	288	575	158	158	315	445	445	890	320.79	35.65	0.39	0.77	0.29	1.82	0.20	0.71
Total	14,450	28,900	245,796	13,872	27,744	235,965	2,875	2,875	5,750	1,575	1,575	3,150	4,450	4,450	8,900	320.79	36.43	0.38	0.75	0.28	1.61	0.21	0.71
ALL PROGRAMS																							
FEI	**27,169**	**54,338**	**393,473**	**22,825**	**45,649**	**337,980**	**2,752**	**2,752**	**5,504**	**1,698**	**1,698**	**3,395**	**4,450**	**4,450**	**8,899**	**194.95**	**25.43**	**0.54**	**1.06**	**0.40**	**1.96**	**0.27**	**1.00**
FEVI	**3,019**	**6,038**	**44,708**	**2,536**	**5,072**	**38,425**	**306**	**306**	**612**	**214**	**214**	**427**	**519**	**519**	**1,039**	**204.77**	**26.16**	**0.52**	**1.03**	**0.39**	**2.34**	**0.24**	**0.95**
Total	**30,188**	**60,376**	**438,181**	**25,361**	**50,721**	**376,405**	**3,058**	**3,058**	**6,116**	**1,911**	**1,911**	**3,822**	**4,969**	**4,969**	**9,938**	**195.93**	**25.56**	**0.54**	**1.06**	**0.40**	**2.00**	**0.27**	**0.99**

Note: Whistler (FEW) is included in the FEI service territory

Program and Service Territory	Annual Gas Savings, Gross (GJ/yr.)		NPV Gas Savings, Gross (GJ)	Annual Gas Savings, Net (GJ/yr.)		NPV Gas Savings, Net (GJ)	Utility Expenditures ($1000s)									Cost of Saved Energy ($/GJ)		Benefit/Cost Ratios					
							Incentives			Non-Incentives			All Spending					TRC	MTRC	Utility	Participant	RIM	Societal
	2012	2013		2012	2013		2012	2013	Total	2012	2013	Total	2012	2013	Total	2012	Levelized						
Efficient Boiler Program																							
FEI	99,145	207,058	2,205,531	81,299	169,788	1,808,536	2,537	2,762	5,298	124	234	358	2,660	2,995	5,656	32.72	3.01	1.71	3.87	3.61	2.57	0.72	4.46
FEVI	11,367	23,244	257,112	9,321	19,060	210,832	290	304	594	14	26	40	304	330	634	32.63	2.91	1.78	4.04	3.75	3.97	0.48	4.46
Total	110,512	230,302	2,462,644	90,620	188,848	2,019,368	2,827	3,066	5,892	138	260	397	2,965	3,325	6,290	32.71	3.00	1.71	3.89	3.63	2.71	0.69	4.46
Light Commercial Boiler Program																							
FEI	8,288	16,872	179,875	6,796	13,835	147,498	97	100	197	32	5	36	128	105	233	18.90	1.53	1.82	4.12	7.10	2.54	0.79	4.74
FEVI	1,184	2,368	26,213	971	1,942	21,494	14	14	28	4	1	4	17	14	32	17.87	1.43	1.90	4.32	7.62	4.04	0.51	4.78
Total	9,472	19,240	206,088	7,767	15,777	168,992	111	114	225	35	5	40	146	119	265	18.77	1.52	1.82	4.14	7.15	2.69	0.77	4.74
Efficient Commercial Water Heater Program																							
FEI	7,031	14,062	113,502	6,679	13,359	107,827	174	174	349	26	26	51	200	200	400	29.91	3.58	1.33	3.02	2.87	2.13	0.68	3.25
FEVI	1,157	2,314	19,143	1,099	2,198	18,186	29	29	57	5	5	9	33	33	66	30.19	3.53	1.36	3.09	2.91	3.21	0.46	3.23
Total	8,188	16,376	132,645	7,779	15,557	126,013	203	203	406	30	30	60	233	233	466	29.95	3.57	1.33	3.03	2.88	2.23	0.65	3.24
Commercial Energy Assessment Program																							
FEI	55,632	55,632	107,441	36,161	36,161	69,836	143	143	285	45	45	90	188	188	375	5.19	5.19	2.25	5.57	1.66	5.16	0.54	5.32
FEVI	18,544	18,544	35,896	12,054	12,054	23,332	48	48	95	15	15	30	63	63	125	5.19	5.19	2.25	5.57	1.66	7.78	0.38	5.32
Total	74,176	74,176	143,336	48,214	48,214	93,169	190	190	380	60	60	120	250	250	500	5.19	5.19	2.25	5.57	1.66	5.42	0.53	5.32
Spray Valve Program																							
FEI	2,961	5,922	24,923	2,606	5,211	21,932	43	43	86	3	3	5	45	45	91	17.45	4.00	2.67	6.18	2.38	4.43	0.63	6.20
FEVI	333	666	2,834	293	586	2,494	5	5	10	0	0	1	5	5	10	17.44	3.97	2.70	6.25	2.40	6.58	0.43	6.20
Total	3,294	6,588	27,758	2,899	5,797	24,427	48	48	95	3	3	6	51	51	101	17.45	4.00	2.67	6.19	2.38	4.64	0.61	6.20
Commercial Custom Design Program																							
FEI	122,464	218,647	2,024,865	110,218	196,782	1,822,379	4,262	3,326	7,588	954	375	1,328	5,216	3,700	8,916	47.32	4.75	1.74	3.96	2.21	3.11	0.63	4.36
FEVI	32,061	58,342	555,991	28,855	52,508	500,392	1,109	937	2,045	58	85	143	1,167	1,022	2,189	40.44	4.24	1.92	4.37	2.48	4.62	0.45	4.66
Total	154,525	276,989	2,580,857	139,073	249,290	2,322,771	5,371	4,262	9,633	1,012	460	1,472	6,383	4,722	11,105	45.89	4.70	1.76	4.00	2.24	3.26	0.61	4.39
Continuous Optimization Program																							
FEI	103,635	236,880	1,438,891	103,635	236,880	1,438,891	1,760	2,453	4,213	216	239	455	1,976	2,692	4,668	19.07	3.12	0.98	2.24	3.19	2.18	0.47	2.32
FEVI	4,230	9,870	60,979	4,230	9,870	60,979	72	104	176	14	16	30	86	120	206	20.22	3.24	0.98	2.24	3.06	2.94	0.35	2.28
Total	107,865	246,750	1,499,870	107,865	246,750	1,499,870	1,832	2,557	4,389	230	255	485	2,062	2,812	4,874	19.12	3.13	0.98	2.24	3.17	2.25	0.46	2.32
Commercial Kitchen Program																							
FEI	1,404	3,300	26,498	1,334	3,135	25,173	60	81	141	2	2	5	62	83	146	46.76	5.56	1.09	2.48	1.85	1.90	0.60	2.67
FEVI	140	351	2,885	140	351	2,885	6	9	15	2	2	3	8	11	18	53.40	6.00	1.03	2.33	1.72	2.76	0.41	2.44
Total	1,545	3,651	29,383	1,475	3,486	28,058	66	90	156	4	4	8	70	94	164	47.39	5.61	1.08	2.46	1.84	1.99	0.58	2.64
MURB Program																							
FEI	19,800	50,400	210,495	17,820	45,360	189,446	371	574	945	28	28	56	399	602	1,001	22.41	5.07	2.07	4.79	1.89	3.64	0.59	4.81
FEVI	4,950	12,150	51,390	4,455	10,935	46,251	93	135	228	7	7	14	100	142	242	22.41	5.03	2.09	4.83	1.90	5.30	0.41	4.80
Total	24,750	62,550	261,886	22,275	56,295	235,697	464	709	1,173	35	35	70	499	744	1,243	22.41	5.06	2.07	4.79	1.89	3.81	0.57	4.81
Process Heat Program																							
FEI	26,250	52,500	560,061	21,000	42,000	448,049	525	525	1,050	14	14	27	539	539	1,077	25.64	2.32	2.11	4.78	4.69	3.02	0.75	5.51
FEVI	2,500	5,000	55,348	2,000	4,000	44,278	50	50	100	2	2	3	52	52	103	25.75	2.25	2.19	4.97	4.84	4.71	0.49	5.49
Total	28,750	57,500	615,409	23,000	46,000	492,327	575	575	1,150	15	15	30	590	590	1,180	25.65	2.31	2.12	4.80	4.70	3.19	0.73	5.50
Fireplace Timers Pilot Program																							
FEI	0	25,650	104,109	0	25,650	104,109	0	428	428	68	23	90	68	450	518		4.67	2.07	4.72	2.09	4.00	0.62	4.79
FEVI	0	2,850	11,726	0	2,850	11,726	0	48	48	8	3	10	8	50	58		4.63	2.09	4.79	2.11	5.89	0.43	4.78

Total	0	28,500	115,835	0	28,500	115,835	0	475	475	75	25	100	75	500	575		4.67	2.07	4.73	2.09	4.19	0.60	4.79
Radiant Tube Heaters Pilot Program																							
FEI	748	748	8,258	748	748	8,258	12	0	12	8	0	8	20	0	20	26.62	2.41	3.71	8.46	4.45	7.71	0.74	9.64
Energy Specialists Program																							
FEI	0	0	0	0	0	0	840	780	1,620	195	144	339	1,035	924	1,959			0.00	0.00	0.00	1.00	0.00	0.00
FEVI	0	0	0	0	0	0	120	120	240	22	16	38	142	136	278			0.00	0.00	0.00	1.00	0.00	0.00
Total	0	0	0	0	0	0	960	900	1,860	217	160	377	1,177	1,060	2,237			0.00	0.00	0.00	1.00	0.00	0.00
ALL PROGRAMS																							
FEI	**447,358**	**887,671**	**7,004,449**	**388,295**	**788,909**	**6,191,933**	**10,824**	**11,388**	**22,212**	**1,713**	**1,135**	**2,848**	**12,537**	**12,523**	**25,060**	**32.29**	**3.91**	**1.44**	**3.34**	**2.67**	**2.59**	**0.61**	**3.60**
FEVI	**76,466**	**135,699**	**1,079,518**	**63,418**	**116,354**	**942,851**	**1,834**	**1,801**	**3,635**	**149**	**176**	**325**	**1,983**	**1,977**	**3,960**	**31.27**	**4.07**	**1.71**	**3.98**	**2.58**	**4.20**	**0.44**	**4.15**
Total	**523,824**	**1,023,370**	**8,083,967**	**451,713**	**905,263**	**7,134,784**	**12,658**	**13,189**	**25,847**	**1,861**	**1,312**	**3,173**	**14,520**	**14,500**	**29,020**	**32.14**	**3.94**	**1.47**	**3.41**	**2.66**	**2.78**	**0.58**	**3.67**

Note: Whistler (FEW) is included in the FEI service territory

Program and Service Territory	Annual Gas Savings, Gross (GJ/yr.)		NPV Gas Savings, Gross (GJ)	Annual Gas Savings, Net (GJ/yr.)		NPV Gas Savings, Net (GJ)	Utility Expenditures ($1000s)									Cost of Saved Energy ($/GJ)		Benefit/Cost Ratios					
							Incentives			Non-Incentives			All Spending										
	2012	2013		2012	2013		2012	2013	Total	2012	2013	Total	2012	2013	Total	2012	Levelized	TRC	MTRC	Utility	Participant	RIM	Societal
Residential Mass Education on Conservation and Energy Literacy																							
FEI	0	0	0	0	0	0	0	0	0	590	590	1,179	590	590	1,179			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	66	66	131	66	66	131			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	655	655	1,310	655	655	1,310			0.00	0.00	0.00		0.00	0.00
Residential Home Shows and Community Events Outreach																							
FEI	0	0	0	0	0	0	0	0	0	320	320	639	320	320	639			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	76	76	151	76	76	151			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	395	395	790	395	395	790			0.00	0.00	0.00		0.00	0.00
Canadian Home Builders' Association Promotions and Support																							
FEI	0	0	0	0	0	0	0	0	0	153	153	306	153	153	306			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	17	17	34	17	17	34			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	170	170	340	170	170	340			0.00	0.00	0.00		0.00	0.00
Residential Outreach Education Tools																							
FEI	0	0	0	0	0	0	0	0	0	180	180	360	180	180	360			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	20	20	40	20	20	40			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	200	200	400	200	200	400			0.00	0.00	0.00		0.00	0.00
Energy Champion Program																							
FEI	0	0	0	0	0	0	0	0	0	688	688	1,376	688	688	1,376			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	162	162	324	162	162	324			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	850	850	1,700	850	850	1,700			0.00	0.00	0.00		0.00	0.00
Home Efficiency Measures																							
FEI	0	0	0	0	0	0	0	0	0	405	423	828	405	423	828			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	45	47	92	45	47	92			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	450	470	920	450	470	920			0.00	0.00	0.00		0.00	0.00
Municipal Partnerships - Other																							
FEI	0	0	0	0	0	0	0	0	0	135	144	279	135	144	279			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	15	16	31	15	16	31			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	150	160	310	150	160	310			0.00	0.00	0.00		0.00	0.00
Medium-Large Commercial Education Sessions																							
FEI	0	0	0	0	0	0	0	0	0	63	63	126	63	63	126			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	7	7	14	7	7	14			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	70	70	140	70	70	140			0.00	0.00	0.00		0.00	0.00
Small Commercial Education and Outreach																							
FEI	0	0	0	0	0	0	0	0	0	80	80	160	80	80	160			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	20	20	40	20	20	40			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	100	100	200	100	100	200			0.00	0.00	0.00		0.00	0.00
Commercial Trade Shows and Association Events																							
FEI	0	0	0	0	0	0	0	0	0	130	130	259	130	130	259			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	31	31	61	31	31	61			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	160	160	320	160	160	320			0.00	0.00	0.00		0.00	0.00
Commercial Multi-Family																							
FEI	0	0	0	0	0	0	0	0	0	297	297	594	297	297	594			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	33	33	66	33	33	66			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	330	330	660	330	330	660			0.00	0.00	0.00		0.00	0.00
Behaviour Programs - Online Community Site																							
FEI	0	0	0	0	0	0	0	0	0	200	216	416	200	216	416			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	50	54	104	50	54	104			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	250	270	520	250	270	520			0.00	0.00	0.00		0.00	0.00
Behaviour Programs - Energy Specialists																							
FEI	0	0	0	0	0	0	0	0	0	180	180	360	180	180	360			0.00	0.00	0.00		0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	20	20	40	20	20	40			0.00	0.00	0.00		0.00	0.00
Total	0	0	0	0	0	0	0	0	0	200	200	400	200	200	400			0.00	0.00	0.00		0.00	0.00

Conservation Assistance - Education and Outreach																				
FEI	0	0	0	0	0	0	0	0	0	216	216	432	216	216	432	0.00	0.00	0.00	0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	54	54	108	54	54	108	0.00	0.00	0.00	0.00	0.00
Total	0	0	0	0	0	0	0	0	0	270	270	540	270	270	540	0.00	0.00	0.00	0.00	0.00
School Programs: Class and Online Curriculum																				
FEI	0	0	0	0	0	0	0	0	0	40	0	40	40	0	40	0.00	0.00	0.00	0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	10	0	10	10	0	10	0.00	0.00	0.00	0.00	0.00
Total	0	0	0	0	0	0	0	0	0	50	0	50	50	0	50	0.00	0.00	0.00	0.00	0.00
School Programs: K-12 In-Class Programs and Presentations																				
FEI	0	0	0	0	0	0	0	0	0	227	227	454	227	227	454	0.00	0.00	0.00	0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	53	53	106	53	53	106	0.00	0.00	0.00	0.00	0.00
Total	0	0	0	0	0	0	0	0	0	280	280	560	280	280	560	0.00	0.00	0.00	0.00	0.00
School Programs: K-12 Home Efficiency Measures																				
FEI	0	0	0	0	0	0	0	0	0	216	216	432	216	216	432	0.00	0.00	0.00	0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	24	24	48	24	24	48	0.00	0.00	0.00	0.00	0.00
Total	0	0	0	0	0	0	0	0	0	240	240	480	240	240	480	0.00	0.00	0.00	0.00	0.00
School Programs: Post Secondary																				
FEI	0	0	0	0	0	0	0	0	0	162	162	324	162	162	324	0.00	0.00	0.00	0.00	0.00
FEVI	0	0	0	0	0	0	0	0	0	18	18	36	18	18	36	0.00	0.00	0.00	0.00	0.00
Total	0	0	0	0	0	0	0	0	0	180	180	360	180	180	360	0.00	0.00	0.00	0.00	0.00
ALL PROGRAMS																				
FEI	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**4,281**	**4,284**	**8,564**	**4,281**	**4,284**	**8,564**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
FEVI	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**720**	**717**	**1,436**	**720**	**717**	**1,436**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5,000**	**5,000**	**10,000**	**5,000**	**5,000**	**10,000**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Note: Whistler (FEW) is included in the FEI service territory

Program and Service Territory	Annual Gas Savings, Gross (GJ/yr.)		NPV Gas Savings, Gross (GJ)	Annual Gas Savings, Net (GJ/yr.)		NPV Gas Savings, Net (GJ)	Utility Expenditures ($1000s)									Cost of Saved Energy ($/GJ)		Benefit/Cost Ratios					
							Incentives			Non-Incentives			All Spending					TRC	MTRC	Utility	Participant	RIM	Societal
	2012	2013		2012	2013		2012	2013	Total	2012	2013	Total	2012	2013	Total	2012	Levelized						
Industrial Technology Retrofit Program																							
FEI	181,468	362,936	2,689,407	163,321	326,642	2,420,466	1,487	1,487	2,974	223	223	446	1,710	1,710	3,420	10.47	1.36	3.90	8.89	7.47	5.51	0.79	9.48
Industrial Energy Audit and Analysis Program																							
FEI	0	56,970	393,198	0	51,273	353,879	353	353	705	35	35	70	388	388	775		2.11	2.78	6.28	4.86	4.02	0.75	6.69
ALL PROGRAMS																							
FEI	**172,758**	**402,486**	**2,879,123**	**155,482**	**362,237**	**2,591,211**	**1,840**	**1,840**	**3,679**	**258**	**258**	**516**	**2,098**	**2,098**	**4,195**	**13.49**	**1.56**	**3.73**	**8.44**	**6.49**	**5.34**	**0.78**	**9.00**

Note: Whistler (FEW) is included in the FEI service territory

Program and Service Territory	Annual Gas Savings, Gross (GJ/yr.)		NPV Gas Savings, Gross (GJ)	Annual Gas Savings, Net (GJ/yr.)		NPV Gas Savings, Net (GJ)	Utility Expenditures ($1000s)									Cost of Saved Energy ($/GJ)		Benefit/Cost Ratios					
							Incentives			Non-Incentives			All Spending										
	2012	2013		2012	2013		2012	2013	Total	2012	2013	Total	2012	2013	Total	2012	Levelized	TRC	MTRC	Utility	Participant	RIM	Societal
Thermal Curtains																							
FEI	6,990	20,970	191,080	6,990	20,970	191,080	131	261	392	51	51	101	181	312	493	25.94	2.47	1.98	4.48	4.28	3.09	0.74	4.96
FEVI	0	6,990	64,190	0	6,990	64,190	0	131	131	17	17	34	17	148	164		2.41	2.05	4.64	4.43	4.82	0.49	4.99
Total	6,990	27,960	255,270	6,990	27,960	255,270	131	392	523	68	68	135	198	460	658	28.35	2.46	1.99	4.50	4.30	3.26	0.71	4.96
Solar Air Heating Systems																							
FEI	2,564	6,410	78,404	2,564	6,410	78,404	105	158	263	93	93	185	198	250	448	77.03	5.49	1.31	2.97	2.09	2.78	0.63	3.66
Occupancy Sensors/Controls																							
FEI	10,044	10,044	74,438	10,044	10,044	74,438	810	0	810	77	77	153	887	77	963	88.26	12.87	1.17	1.83	0.77	1.47	0.85	2.16
FEVI	1,116	1,116	8,427	1,116	1,116	8,427	90	0	90	9	9	17	99	9	107	88.26	12.63	1.20	1.86	0.79	1.82	0.70	2.16
Total	11,160	11,160	82,866	11,160	11,160	82,866	900	0	900	85	85	170	985	85	1,070	88.26	12.84	1.18	1.83	0.77	1.51	0.83	2.16
Condensing Make Up Air (MUA) Units																							
FEI	0	1,444	12,842	0	1,444	12,842	0	6	6	24	24	48	24	30	54		4.04	2.46	5.56	2.64	18.44	0.67	6.10
FEVI	0	361	3,315	0	361	3,315	0	2	2	6	6	12	6	8	14		3.93	2.54	5.74	2.73	29.76	0.46	6.09
Total	0	1,805	16,157	0	1,805	16,157	0	8	8	30	30	60	30	38	68		4.03	2.47	5.58	2.65	19.57	0.65	6.10
Advanced Control of Lumber Drying Using an Energy Management System																							
FEI	0	19,050	77,320	0	19,050	77,320	0	75	75	23	23	45	23	98	120		1.47	6.98	12.65	6.67	8.73	1.04	13.65
FEVI	0	6,350	26,127	0	6,350	26,127	0	25	25	8	8	15	8	33	40		1.45	7.07	12.82	6.73	12.72	0.73	13.64
Total	0	25,400	103,448	0	25,400	103,448	0	100	100	30	30	60	30	130	160		1.46	6.99	12.67	6.67	9.13	1.01	13.65
Catalytic Radiant Burner Technology																							
FEI	0	4,917	33,936	0	4,917	33,936	0	195	195	39	39	79	39	234	274		7.59	0.79	1.78	1.36	1.64	0.54	1.89
FEVI	0	1,639	11,581	0	1,639	11,581	0	65	65	13	13	26	13	78	91		7.45	0.80	1.82	1.38	2.36	0.39	1.89
Total	0	6,556	45,518	0	6,556	45,518	0	260	260	53	53	105	53	313	365		7.58	0.79	1.78	1.36	1.71	0.52	1.89
Ceramic Manufacturing Using Microwave Assist Technology																							
FEI	0	12,000	141,979	0	12,000	141,979	0	175	175	53	53	105	53	228	280		1.86	3.61	8.38	6.22	6.74	0.77	10.25
ALL PROGRAMS																							
FEI	**19,598**	**74,835**	**610,000**	**19,598**	**74,835**	**610,000**	**1,046**	**870**	**1,916**	**358**	**358**	**716**	**1,404**	**1,228**	**2,632**	**71.62**	**4.18**	**1.81**	**3.68**	**2.57**	**2.79**	**0.78**	**4.25**
FEVI	**1,116**	**16,456**	**113,641**	**1,116**	**16,456**	**113,641**	**90**	**222**	**312**	**52**	**52**	**104**	**142**	**274**	**416**	**127.24**	**3.51**	**2.00**	**4.05**	**2.96**	**4.19**	**0.55**	**4.38**
Total	**20,714**	**91,291**	**723,641**	**20,714**	**91,291**	**723,641**	**1,136**	**1,092**	**2,228**	**410**	**410**	**820**	**1,546**	**1,502**	**3,048**	**74.62**	**4.09**	**1.84**	**3.73**	**2.62**	**2.99**	**0.73**	**4.27**

Note: Whistler (FEW) is included in the FEI service territory