Zapped

A Review of BC Hydro's Purchase of Power from Independent Power Producers conducted for the Minister of Energy, Mines and Petroleum Resources

By: Ken Davidson

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About the Reviewer

Ken Davidson holds a BSc in pure mathematics and is qualified as a professional accountant. He is a commercial banker by trade, specializing in restructuring and asset realization transactions.

Mr. Davidson worked as Director in Provincial Treasury and Treasury Board Staff from 1989 to 1997. He created the Program Evaluation function in Treasury Board and managed that function for four years. In this role, Mr. Davidson reported directly to the Deputy and the Minister and was charged with investigating and bringing to resolution, issues and concerns raised by Cabinet.

Ken has been a consultant in private practice since 1997 and has been recognized on Master Standing Offers maintained by numerous provincial ministries as a qualified consultant in areas including Procurement and Contracting Advisory Services, Strategic Planning, Program Evaluation, Business Process Improvement and Negotiations and Evaluation.

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Executive Summary

British Columbia Hydro and Power Authority (BC Hydro) began purchasing power from independent power producers in the mid-1980s. Independent power producer (IPP) projects were initially developed at a small volume and without market price impacts.

Government's approach began to change and by 2002, a move to green/clean power and energy self-sufficiency was expressed in the 2002 Energy Plan. The direction was further clarified with the 2007 Energy Plan–Vision for Clean Energy Leadership, and the 2010 *Clean Energy Act*. Government provided clear direction that moving forward, BC Hydro would not increase its internal generating capacity and was no longer allowed to rely on importing power to meet demand (also known as load).

To add urgency to the process, Government directed BC Hydro to apply new parameters to its energy planning processes. These parameters created the appearance of an urgent need for 8,500 gigawatt hours (GWh) per year of new Firm energy.

As Government had removed the options for BC Hydro to increase its internal generating capacity or importing power to meet demand, this need for new energy could only be met through procurements to elicit proposals from independent power producers. The demand for energy volumes (that was not actually required) and price signalling presented to the market drove prices higher.

This report draws three conclusions:

- BC Hydro bought too much energy and energy with the wrong profile,
- BC Hydro paid too much for the energy it bought, and
- BC Hydro undertook these actions at the direction of Government.

Government directed BC Hydro to purchase 8,500 GWh of Firm energy BC Hydro did not need. This direction of BC Hydro's actions is manifest in the Response EPAs (Electricity Purchase Agreements) through which BC Hydro managed to acquire 9,500 GWh of blended energy, which is equivalent to 8,075 GWh of Firm energy. The Response EPAs cost ratepayers an estimated $16.2 billion over 20 years, the estimated period during which BC Hydro will likely not need the energy Government directed it to buy. The annual impact of this surplus energy to BC Hydro ratepayers is estimated as $808 million per year or ~$200 per year per residential ratepayer, which is equivalent to $4,000 per residential ratepayer over 20 years. The $16.2 billion Estimate is believed to be conservative.

The Estimate is associated with the cost of buying energy from the Response EPAs, during the period BC Hydro likely will not need the energy. Even if load grows to the point BC Hydro needs this energy, BC Hydro will be faced with the issue that it is paying too much for the energy.

As demonstrated in Section 31, over the balance of the term of the Response EPAs, BC Hydro will lose an additional ~$6.8 billion selling energy to ratepayers for rates less than BC Hydro is buying it from IPPs.

The EPAs offer various forms of inflation protection to the contractors; in some cases, full Consumer Price Index (CPI) protection. Given the contract terms of the EPAs and the quantity of energy covered, the estimated impact of the inflation risk (assuming a 2% CPI that is often used by BC Hydro for its planning) could potentially add another $1 billion to the cost Estimate over the next 20 years. The three NTL EPAs extend for 36 years beyond the 20-year period of the Estimate and carry an incremental inflation risk over this extended period in the range of $7 billion.

Beyond the volume of non-commercial EPAs BC Hydro has taken on, there is also a series of other non-commercial activities it has assumed at the direction of Government. In aggregate, these non-commercial transactions are now impacting customer electricity rates and will continue to do so for many years to come.

As this problem did not happen overnight, there will be no quick fix. However, there is an opportunity to address these financial issues when the EPAs for IPP projects expire and can be renewed on a commercial and market rate basis.

This report offers recommendations:

- on a renewal strategy that will moderate the future financial impacts of the EPAs as they mature and there is an opportunity for renewal. It is recommended that BC Hydro should make only one offer for renewal of EPAs associated with projects that generate Intermittent energy and that offer is priced at the real market value of the energy generated, the Mid-C rate.
- for the reversal of the "self-sufficiency" mandate, which interfered with the energy planning processes to create the apparent need for additional IPP energy.
- On a strategy to improve the transparency around future non-commercial transactions that Government may choose to direct BC Hydro to undertake.
- to return to the British Columbia Utilities Commission (BCUC) its full historic oversight mandate to protect the interests of ratepayers, with some latitude to deal with transactions that need to be managed to maturity.

Introduction

1) Glossary and Basic Concepts

BC Hydro means the British Columbia Hydro and Power Authority, a Crown corporation that is accountable to the Government and owned by the people of British Columbia

BCUC means the British Columbia Utilities Commission

Biomass generation typically uses waste from saw mills and pulp mills to generate heat, steam and electricity that often supports the mill operations with surplus power sold back to BC Hydro under an EPA. Biomass power projects generate Firm power and have some ability to Dispatch.

COD means Commercial Operations Date, the date upon which an IPP begins to sell electricity to BC Hydro under an EPA.

Dispatchable refers to the ability of a power generator to increase or decrease output quickly and on demand. Storage hydro and biomass generating facilities are typically Dispatchable. Run-of-River, Wind and Solar power facilities are typically non-Dispatchable as they can generate only when the water flows, the wind blows or the sun shines.

EMPR means the Ministry of Energy, Mines and Petroleum Resources to which BC Hydro is accountable as a Crown corporation. This Ministry may have had different names over the years. EMPR supports the Minister in governance responsibilities but is a public service entity and not a political entity.

EPA means an electricity purchase agreement (in this case) issued pursuant to a BC Hydro purchase of power.

Estimate means the estimated cost of the 8,500 GWh of Firm energy BC Hydro was directed to buy by Government. The value of the Estimate is developed in Section 32.

Firm energy refers to the ability of an energy resource to reliably deliver a specified amount of energy within specified time periods. BC Hydro typically uses the term "firm energy" from two different perspectives; on a planning basis and on a contractual basis.

Planning Firm energy: is energy that is available at all times. However, for planning purposes, BC Hydro uses the maximum amount of annual energy that a hydroelectric resource can produce under critical water conditions.

Contractually Firm energy: many EPAs include an obligation on the IPP to deliver a specified amount of predictable energy within specified periods (e.g., hourly or within a season). This is the contractually Firm energy. Notwithstanding the EPA may specify an amount of contractually Firm energy, Run-of-River, Wind and Solar IPPs are still considered Intermittent energy sources.[1] If the IPP fails to meet that required contractually Firm energy obligation, the IPP is subject to liquidated damages, which must be paid to BC Hydro for its energy shortfalls. When an IPP delivers energy under its EPA beyond the contractually Firm energy, this additional energy is considered to be non-Firm under the EPA.

Freshet is the snowmelt period typically from May to July each year when Run-of-River facilities generate more electricity due to increased water flows. BC Hydro has had an oversupply of energy during the freshet period for many years and has sold the excess energy on the market at very low prices.

Gate price is the energy price as per an EPA.

Government refers to the elected officials that govern British Columbia at a given point in time. Distinct from EMPR.

Heritage Assets are defined in the *Clean Energy Act* to include all of the transmission and distribution infrastructure in place when the Act was passed as well as those generating facilities identified in Schedule 1 to the Act. The generating facilities listed include the electricity facilities on the Peace and Columbia Rivers like the W.A.C. Bennett, Peace Canyon, Mica and Revelstoke dams. Heritage Assets are of interest to this review as the 2010 *Clean Energy Act* restricted BC Hydro's internal generating capacity to these existing assets and assets identified in Schedule 1, which required BC Hydro to meet all incremental future demand through energy purchased from IPPs. A list of Heritage Assets and their dependable capacity is set out in Appendix B.

2006 Integrated Electricity Plan (**IEP**) refers to the BC Hydro plan filed on March 29, 2006 with the BCUC. It included the Long-Term Acquisition Plan (LTAP). On May 11, 2007, the BCUC released its decision on the 2006 IEP/LTAP application.

1 Contractually Firm energy from an Intermittent resource still requires further firming against dispatchable resources before it can be used to meet Load.

Integrated Power Offer (**IPO**) was designed to support the delivery of integrated offers to industrial customers that optimize all cost effective electricity-related opportunities at a customer site.

Intermittent refers to an energy source that is not continuously available and availability is not directly controlled. Intermittent energy sources may be predictable but cannot be dispatched to meet changes in load. Wind, Run-of-River hydro and Solar are considered to be Intermittent resources.

Intermittent vs. Firm Power–when considering the value of power, it should be noted that power from Intermittent sources are extremely difficult to sell "as is." Intermittent power has greater market value only when it can be absorbed into a system where it can be balanced and firmed. Intermittent power trades at a material discount when it is sold without first being firmed. Run-of-River and Wind power are Intermittent and of lesser value unless it is balanced and firmed within the BC Hydro system. Solar power is a more predictable resource but is still has the same intermittency issue.

IPP means an Independent Power Producer.

Levelized price means a price that has been adjusted to allow an "apples to apples" comparison between EPAs or contract pricing proposals within different dates of commercial operations, escalation rates, lengths of contract term and initial gate prices. A levelized price is expressed in real dollars (e.g., $2018) for ease of comparison.

Minister or Minister of Energy, Mines and Petroleum Resources means the elected Member of the Legislative Assembly that is appointed to this Cabinet position that oversees the Ministry and BC Hydro.

Mid-C means the price at which energy trades at the Mid-Columbia hub.

NTL means the Northwest Transmission Line.

Powerex means Powerex Corporation, a wholly-owned subsidiary of BC Hydro.

Response EPAs mean the EPAs resulting under the five calls BC Hydro issued to meet Government's direction that it purchase energy it did not need. The Response EPAs appear in the table entitled "Current Electricity Purchase Agreements with BC Hydro" in Section 31.

Run-of-River means a hydroelectric project that relies on natural stream flows and natural elevation changes along the course of the river, with very limited or no water storage, to generate electricity. Run-of-River power is not Dispatchable, with the majority of energy delivered during Freshet for most projects (except some projects in coastal areas). Run-of-River power is an Intermittent resource.

Solar generation means a power system that converts the energy from sunlight into electricity. At present, while the cost of solar installation is falling, cloud cover and the aspect of the sun at our Northern latitude makes solar solutions sub-optimal in B.C. compared to other jurisdictions. Solar power projects generate Intermittent power that is not dispatchable. Solar power is an Intermittent resource.

Wind generation means a power system that converts the energy from the wind into electricity. Wind power projects generate Intermittent power that is not dispatchable. Wind power is an Intermittent resource.

2) Review Focus and Scope

The Ministry of Energy, Mines and Petroleum Resources (EMPR) is in the process undertaking a two-part comprehensive review of BC Hydro.

The first part focuses primarily on BC Hydro's costs and rates, with the goal of reducing growth in BC Hydro's electricity rates and ensuring sound financial and regulatory oversight of BC Hydro.

The second part will focus on transformational aspects to changing energy markets and assist BC Hydro in developing its next Integrated Resource Plan (IRP).

In order to inform the Comprehensive Review process, the Minister commissioned this review into BC Hydro's purchase of power from IPPs.

This review focuses on these IPP purchases and describes the context in which these purchases were made, the Government directions that focused and then accelerated these IPP purchases, and the activities that occurred ancillary to this effort.

This review considers specifically:

- the Government decisions, policies, legislation and actions that influenced BC Hydro's energy planning processes to create the appearance of need,
- how the appearance of need led BC Hydro to buy large volumes of independent power, and
- how the purchase of large volumes of power beyond BC Hydro's needs and at high prices drove rates higher.

3) Report Approach

IPPs have been actively discussed for 20 years and BC Hydro has released a steady stream of information regarding IPPs and associated topics.

What has been missing from this conversation is an analysis that explains the available information in the context of market influences. This report is an attempt to provide that analysis.

In its development, this report relied primarily on the information that has been released into the public domain. A non-exhaustive listing of the information reviewed appears in Appendix A.

Where possible, interviews were conducted with individuals from EMPR, BC Hydro and Powerex with personal knowledge of the IPP purchases and the history described herein. This report accepted as bona fide the information provided in each interview, then corroborated that information across all interviews and then checked the apparent consensus against available documentation.

The reality of Government is that the deliberations of Cabinet, including all documents intended to inform and facilitate those deliberations, are confidential. Legally, access to cabinet documents is privileged to those specifically involved in that process. Accordingly, there should be no expectations that this review would have access to those documents or could release publicly the content of such documents. In the same manner, the commercial information in the contracts between BC Hydro and its generating partners is confidential and proprietary business information. Accordingly, this review can release the average results for a call but cannot release the exact business terms of any individual EPA that resulted from the call. The review is limited to referencing the results of calls in aggregate and referencing information released in the public realm by other sources.

This report attempts to document chronology of the program development from the information obtained through the interviews, and then to anchor that chronology in the facts and data available publicly. Where gaps in the chronology remain, those have been filled by applying business logic to create the likely bridge between the available data points; the report highlights where this is the case.

Where business logic is used to fill a gap between facts, different interpretations may be available. As the report developed, the course of conduct of Government and BC Hydro became clear. In each case where an interpretation was developed to fill a gap in the facts, the choice of the most likely business logic was informed by the assumption that the established course of conduct continued during that period. The author is confident that in each case, the interpretation with the highest probability of being correct was presented.

Background–BC Hydro and the Energy Market

4) BC Hydro's Independent Power Producer Portfolio

BC Hydro's IPP purchases started in earnest in the mid-1980s. The portfolio remained modest until the launch of the 2002 BC Energy Plan, which directed BC Hydro to no longer construct its own power generation facilities but rather to purchase power from IPPs under an EPA. A boom in water licenses and IPP EPAs resulted and led to rapid growth of new clean energy projects.

The 2007 Energy Plan–Vision for Clean Energy Leadership delivered two mandates to BC Hydro: that at least 90 per cent of all electricity generated in BC must originate from clean, sustainable sources, and BC must become self-sufficient in electrical power (i.e. that BC Hydro would not rely on imported power to meet forecast domestic demand). This created a move towards cleaner Wind and Run-of-River projects and continued the IPP boom.

5) Key Parties and Governance Processes

BC Hydro is a provincial commercial Crown corporation with the mandate to generate, purchase, distribute and sell electricity. As a provincial Crown corporation, the owner and sole shareholder of BC Hydro is the Province of British Columbia. BC Hydro reports to the Provincial Government through the Minister of Energy, Mines and Petroleum Resources and is regulated by the BCUC.

Government's expectations of BC Hydro are primarily expressed through the *Hydro and Power Authority Act*, the *Utilities Commission Act*, *BC Hydro Public Power Legacy and Heritage Contract Act*, the 2010 *Clean Energy Act*, British Columbia's 2007 BC Energy Plan, the CleanBC Plan and through the Mandate Letter from Government to BC Hydro.

In 1988, BC Hydro established Powerex as its wholly-owned electricity marketing subsidiary. As a key participant in energy markets across North America, Powerex trades power, including buying and selling wholesale power, natural gas, and renewable and low-carbon energy and products.

At the direction of the Minister, EMPR staff provide research services and policy support for the proposals the Minister wishes to bring forward to Cabinet for consideration. Policy is decided by Cabinet and is mandated through legislation, regulations and letters of direction.

The BCUC is an independent agency of the Government of B.C. responsible for regulating British Columbia's energy utilities, including regulating the rates charged and service standards and reliability while ensuring that the regulated entities have the opportunity to earn a fair return on their investments. It is quasi-judicial and makes legally binding rulings. The BCUC is governed by its enabling statute, the *Utilities Commission Act*, and other provincial legislation.

6) How Energy is Priced–The Mid-Columbia Price (Mid-C)

There is a grouping of five hydroelectric dams in central Washington State on the Columbia River, which are managed on a coordinated basis. Due to the large number of power buyers and sellers (utilities, generators, traders, including Powerex), the central location on the high-voltage transmission grid and adjacent generating capacity, a trading hub has developed, referred to as Mid-Columbia or "Mid-C." Power flows in a largely unconstrained manner between BC and Washington, in most hours there is an adequate supply of transmission capacity into both areas. Trading began at Mid-C in the mid-1990s.

For reference, there is also a power market in Alberta that Powerex purchases from and sells to; however, the transmission between B.C. and Alberta is highly constrained. This means that when prices are very high in Alberta the transmission capacity fills up and the Alberta power price does not reflect the value of energy in B.C. since it is not possible to send more energy from B.C. to Alberta.

The Mid-Columbia market trades both short term power (the next hour, the next day etc.) "spot rates" and future periods of power delivery going out as far as five years, with rates that vary based on time of day and season when the delivery will occur; all are referred to as the Mid-C price, so time of day, season and term needs to be specified.

It is possible to see the annual variation when viewing the daily Mid-C rate for the past 12 months ending Oct. 31, 2018 (see Appendix C). In the period, daily prices were as low as negative US$1 (-$1) and as high as US $310/Megawatt hour (MWh) with an average daily price of US$33/MWh. (US EIA, Mid-C On Peak Price Nov. 1, 2017 through Oct. 31, 2018). Daily prices show the Mid-C price moving in a range with a very few, but notable outliers. Provided BC Hydro has a balance of dispatchable Firm power and Intermittent power in its portfolio, it can generally avoid requiring market-priced energy during these outlier peak power price events and potentially benefit if it has surplus energy during these times. Powerex, via its agreements with BC Hydro can also capture benefits from outlier events through trading activities if the BC Hydro system is not constrained.

The time of day variance is also material. On a typical day, peak load (6:00 PM–8:00 PM) is valued at a premium of ~30% over the price of energy delivered from 8:00 AM to 2:00 PM.

Similarly, there are material seasonal variances with prices in the spring typically being low due to the freshet (i.e., snowmelt) in the rivers in B.C. and the Pacific Northwest that increases inflows into hydroelectric reservoirs. When there is a lot of water available, the Mid-C spot price moves towards zero, and sometimes lower (as was the case on March 25, 2018) when parties pay to get rid of power. (Note, the scenario where parties pay others to take their power applies primarily to US wind producers who will continue generating power when it is not needed to take advantage of the "Production Tax Credits" paid by their Government).

The historic "seasonal" trade and optimization of BC Hydro's reservoirs changed approximately 10 years ago. In the past, BC Hydro used its considerable storage capacity in its hydroelectric dams to store and shape our usage of power. In times of low prices, BC Hydro would import inexpensive power, primarily from the Pacific Northwest, in the spot market and "save" the water in the dams for periods when its power potential was worth more to domestic customers and in the export market.

The "self-sufficiency" mandate from Government (discussed in detail in Section 31), resulted in BC Hydro acquiring power from IPP projects to meet projected power requirements and the need to have 3,000 GWh of electricity as insurance beyond that level. Legislation then also required BC Hydro to stop generating electricity at Burrard Thermal by 2016. Fulfilling this mandate ultimately reduced BC Hydro's ability to plan to import in times of cheap power and reserve the water and power in its storage dams for a future time when it was worth more. This mandate meant that BC Hydro needed to supplement its own generation with power from IPPs to meet B.C.'s projected power requirements.

Powerex's ability to trade seasonally against BC's storage capacity was dramatically reduced, creating a loss in trading income to BC Hydro. While there is no direct estimate of the loss, a simplistic example can illustrate the materiality of the problem.

Imagine that BC Hydro has 100 MWh of storage room in its reservoir system. Spot Mid-C is $5/MWh. BC Hydro operations reduce generation and Powerex buys the 100 MWh at $5/MWh for import to service demand in BC. At some point later, BC Hydro uses the stored water to generate power when the spot rate is $30/MWh and the power is either consumed domestically or sold into the spot market by Powerex. Either way, an incremental gain of $25 on that 100 MWh of water/generating capacity is achieved.

Now consider the IPPs with which BC Hydro has contracted, such as wind and run-of-river. BC Hydro must take or pay for the energy delivered or deemed to be delivered, so there is no way to reduce the money paid to the IPPs, even if the electricity is not required to serve domestic load. In the example, say there is 75 MWh of power available from IPPs. BC Hydro must take delivery or spill that power, so it can only store 25 MWh (of the 100 MWh discussed in the previous example) in its dams. BC Hydro achieves only 25% of the economic benefit it would have received if Powerex could use the full 100 MWh. [see Section 29 for the practical impact of this example]

The BC Hydro hydroelectric system can store many millions of MWh of additional water, so this example can be repeated a huge number of times; all lost revenue to BC Hydro due to the "self-sufficiency" mandate.

Now consider the same conditions with 150 MWh of IPP energy. In this hour, BC Hydro is receiving 150 MWh of energy from IPPs. The first 100 MWh could be stored by BC Hydro and used at a later period (supplanting the market use of this storage). The last 50 MWh would need to be sold into the market at the existing price of $5/MWh. For the last 50 MWh, BC Hydro paid IPPs on average price more than $100/MWh to generate power it is now forced to sell at $5/MWh.

Note that this discussion is intended to illustrate the impact Intermittent energy can have on trading activities. The discussion also illustrates a second issue of larger financial impact, which occurs when BC Hydro cannot use the Intermittent energy it is now forced to buy at more than $100/MWh and must sell that energy at $5/MWh into a Mid-C market depressed during Freshet.

7) Energy Crisis and Growth of Natural Gas

In mid-2000, the annual average Mid-C spot rate was moving in the C$20-40/MWh range. After a number of years of efforts towards de-regulation by the US Federal Government and the State of California generation substantially fell behind growth in demand. When combined with an exceptionally dry winter, a major gas pipeline disruption in the Desert Southwest and design failures in California's approach to deregulation, markets were vulnerable to market manipulation from Enron. Annual rates ultimately peaked at about C$200/MWh. This period is commonly referred to as the energy crisis. After the acute shortage was finished and with intervention from the US Federal Government, in 2001, Mid-C crashed back to the C$30/MWh range.

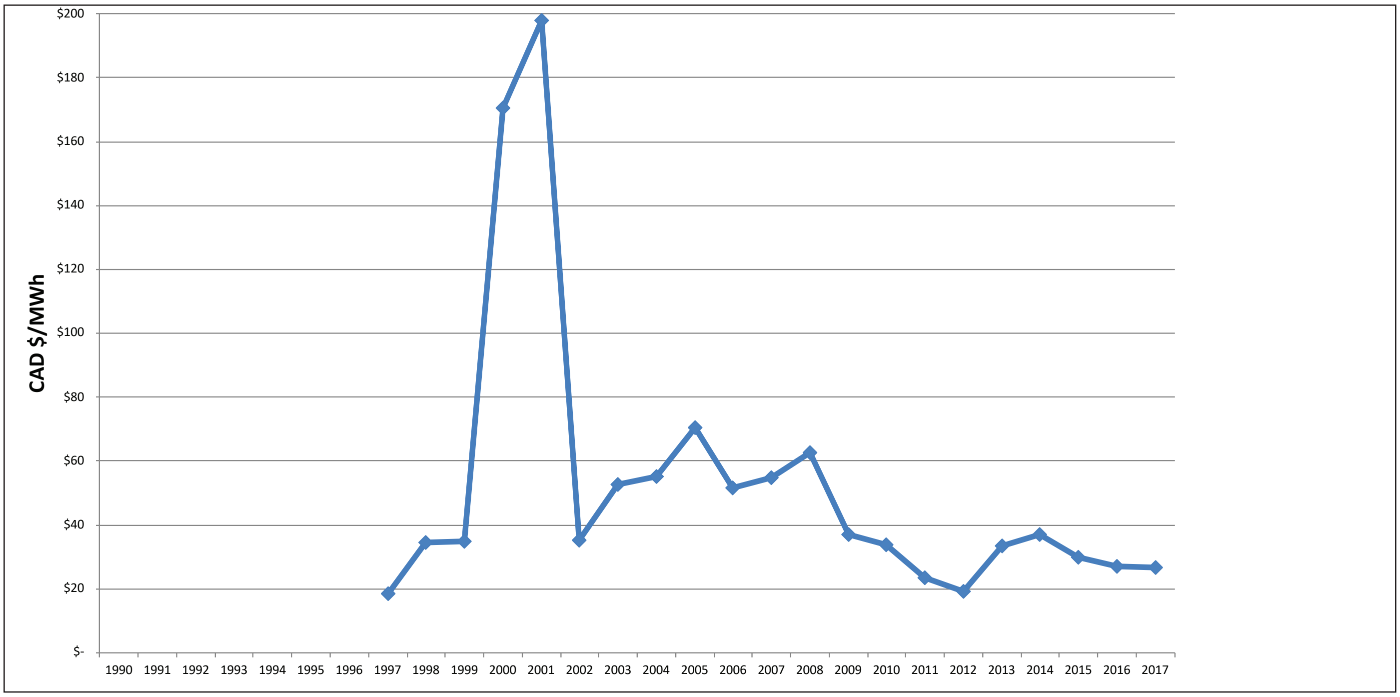


Figure 1: Average Annual Mid-C Price for All Hours (Nominal Dollars)[2]

There was a "never again" response to the energy crisis in many jurisdictions, including California, which built a tremendous amount of natural gas-fired generation and invested heavily in new clean energy projects.

There is a relationship between the price of natural gas and the market price of electricity. In the absence of large hydro dams, utilities typically use gas-fired generation on the margin to manage load variations. Natural gas can be converted into electricity with an 8-10 efficiency factor. As a proxy, 8-10 MMBTUs of gas will generate 1 MWh of electricity. At the peak of the energy crisis, gas went to US$16/MMBTU and electricity went to ~US$160/MWh and beyond.

By 2002, California had defined its vision of acceptable green power initiatives. Many jurisdictions followed defining "acceptable" power as that which eliminates greenhouse gases and also creates local financial stimulus and benefits (local jobs, local taxes, local clean air, etc.). In California, "acceptable" green power initiatives include wind, solar, geothermal, biomass and small hydro, providing that small hydro (defined as less than 30 MW) did not divert water from the natural stream course, likely intended to manage the state's scarce water resources.

2 Source: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017–Pages 72-74

Run-of-river projects are more than a pipe in the river leading to a turbine and then emptying back in the river. Most run-of-river projects have a weir built out into the river that is intended to “divert water from natural stream course”, into the penstock. To date, B.C. run-of-river projects have not been accepted by California as a renewable resource, due to the diversion of water by the weir.

Market prices for natural gas, and hence for electricity remained strong into 2008. The financial crash of 2008 reduced demand and prices. Unfortunately, this crash was timed with a major development in the oil and gas industry, which wasn’t fully appreciated until large amounts of new gas appeared in the market: shale gas and oil and hydraulic fracturing (fracking).

Prior to the shale gas revolution, much of the gas supply came from conventional resources, such as the Western Canadian Sedimentary Basin, off-shore Gulf of Mexico and other resources in the continental United States. The natural gas reference price was and still is based on the Henry Hub in Louisiana, which is near a major supply of conventional natural gas. The Henry Hub is the largest gas hub in North America and other hubs trade off of the Henry Hub price with local adjustments. Many of the shale gas fields happened to be located closer to the load centres and gas started to be priced in the local market, not requiring long distance pipelines to bring gas to load centres.

B.C. gas tends to be priced based on Washington/Alberta/Northern B.C. supply, with transportation adjustments. We now see persistently soft energy prices as B.C. and Alberta gas has been displaced by “local” supply in Eastern Canada and the populous US Northeast.

Despite a market change due to the impact of shale gas and fracking, B.C. pressed forward with its direction for energy self-sufficiency and private sector electricity production with the 2010 *Clean Energy Act* and BC Hydro was required to make large energy procurements of clean and renewable energy from IPPs.

8) Value vs Cost of Generation

Electrical energy is a commodity that trades in a manner similar to West Texas Intermediate crude, a grade of crude oil that is a benchmark in oil pricing. The value of electricity is the value it can be traded for on the open market. In B.C.’s case, the nearest market hub is in the United States and the benchmark price is Mid-C.

In the discussion around the creation of IPPs, “cost of generation” is often used as a proxy for “value.” This creates a logical misalignment: the two concepts are not the same.

“**Cost**” means the cost to produce a megawatt for an hour. Cost can be defined as a short run Cost, based on the Intermittent cost of running the facility, or as a long run Cost including capital cost, O&M etc.

“**Value**” to ratepayers means the benefit to ratepayers of delivering the power to them when they need it. A simple proxy value for energy would be its market value (i.e. if it was bought or sold at the Mid-C price).

In a discussion of a generator or system of generators, there are two other important definitions:

> “**Capacity**” means the ability to produce a maximum quantity of energy at a moment in time (typically expressed in megawatts or MW). Capacity is what ensures the ability to meet load at any moment in time.
>
> “**Energy**” means the amount of electricity generated over some period of time, undifferentiated by time of day, year etc. (typically expressed in megawatt hours or MWh).

For example, BC Hydro generates 55,000,000 MWh of electricity in a year, or an average capacity of 6,279 MW all year long (being 55 Million MWh / 8760 hours in a year). Another example is Burrard Thermal, which, before BC Hydro was directed to decommission it in 2016, had a generating Capacity of approximately 900 MW, and could generate theoretical Energy potential of 7,884,000 MWh if it were run at full capacity all year long.

The power B.C. generates can be substituted for power imported or exported based on the Mid-C rate.

A generator with an associated storage dam may be designed and built with a maximum operating capacity of 100 MW and may have enough available water on an annual basis to produce on average 50 MW. Because water may be stored in the dam and used at the discretion of the operator (i.e. dispatchable), it would be generally able to produce anywhere between zero and 100 MW in any one hour as required to meet domestic load or external market needs.

A run-of-river project may have rated capacity of 100 MW and will typically generate that maximum power at spring freshet (at the same time as almost all other Run-of-River hydro generation), and at reduced and Intermittent levels during other times of the year. The spring freshet is exactly when the Pacific Northwest also has the most water and the highest generating capacity. The spring freshet is the point in the annual price cycle when the Mid-C rate is lowest because supply is the highest. Accordingly, nighttime power at freshet often has little to no value.

Simply put, the value of a generator at a storage dam is materially more than the value of a generator at a Run-of-River project. The value of power is simply the amount of energy, multiplied by the rate it can be sold for in the market; in BC Hydro's case, at the Mid-C rate. In the case of a storage dam, it is possible to choose when to generate and sell the power. With run-of-river, it is necessary to accept the power as it is generated and to sell it into the market prevailing at that moment.

Assuming two plants, one with storage (a dispatchable plant that can be turned on or off) and one without storage (a Run-of-River plant) both have 100 MW of generating capacity, both produce an average of 55 MW (481,800 MWh of Energy over the course of the year).

Plant 1 with storage is able to capture the best hours of the year (the hours with highest market value). "Best" could mean both avoiding buying power to supply load at periods of high market prices or selling energy into the market in the best hours. A dispatchable plant can be adjusted to do this.

Plant 2 with no storage requires that the energy it generates be sold or used as it is generated. If this generation occurs primarily during freshet, then the "value" of the energy it generates is the amount that energy can be sold for in the Mid-C market. Whether or not it is actually sold into the Mid-C market is a moot point if consuming the output of Plant 2 inside B.C. means that BC Hydro is prevented from buying from a low price Mid-C market, then "value" is the same.

Cost of generation is immaterial to the value of the asset to BC Hydro or to the ratepayers. The value of electricity is set by the open market and the market doesn't care how much it costs to generate the power. In our region, there is only one determinant market and it is the Mid-C Hub.

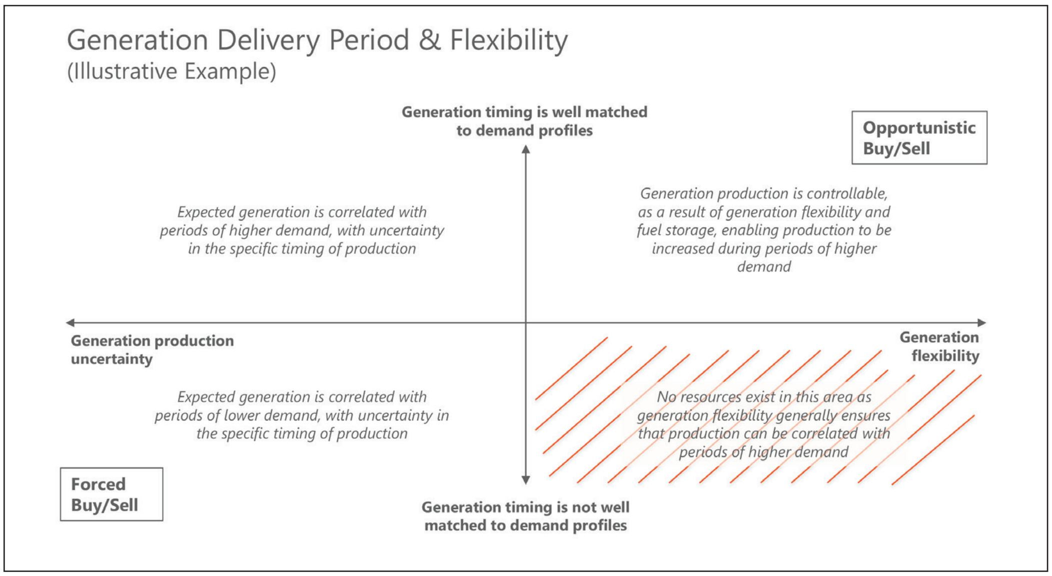
As will be shown in this report, BC Hydro procured the vast majority of its IPP energy, much of which was not needed, through competitive processes or based on the results of recent competitive processes. However, BC Hydro evaluated the proposals based upon the cost per MWh the projects offered as compared to the offers from competing bids and/or the results of similar procurement processes carried out by BC Hydro or in other jurisdictions, not the market value of the energy produced.

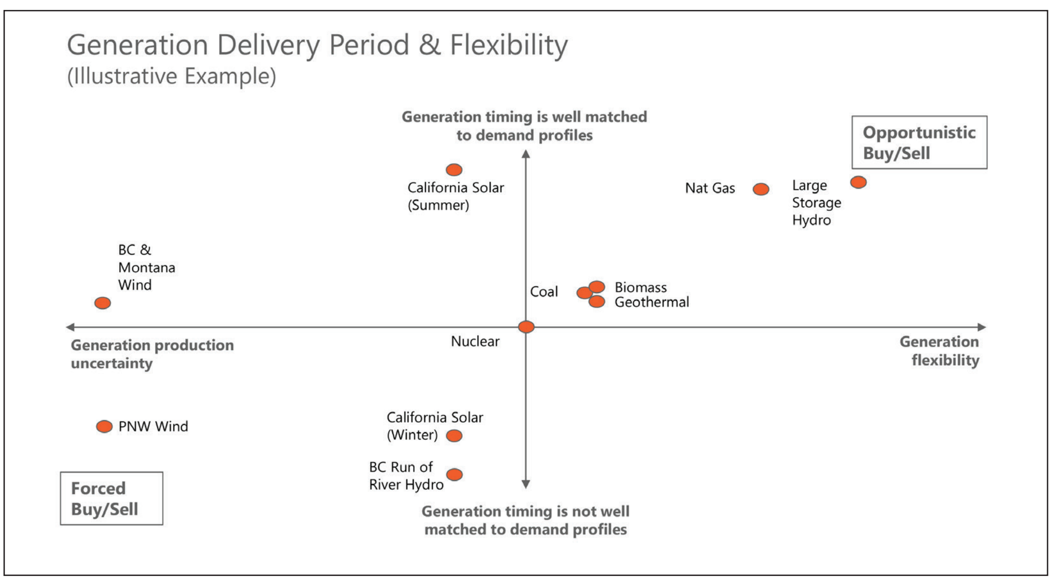
9) Dispatchability vs Variability vs Uncertainty

These are terms that describe the amount of generation control and predictability of generation on a day to day/hour to hour basis.

- Uncertainty is a measure as to whether the power is available when it is needed by the load/customers.
- Dispatchability is a measure as to how the rate of power generation can be managed to meet load.

Powerex explains the concept with the following illustrative charts on Generation Delivery Period and Flexibility.





Graphs are both generalized conceptual illustrations only

A dispatchable source of electricity is a system that can be turned on or off, or where the power output can be supplied on demand. Most conventional power sources such as hydroelectric storage dams and natural gas power plants are dispatchable, and the rate of their power generation can be adjusted in order to meet the always changing electricity demands of the population. In contrast, many renewable energy sources are Intermittent and non-dispatchable. For example, Run-of-River hydro can only generate when the water flows, wind can only generate electricity when the wind blows and solar when the sun shines.

Dispatch times

Dispatchable sources must be able to ramp up or down relatively quickly. Different types of power plants have different dispatch times:

- Fast (seconds): Large hydroelectric storage dam facilities can dispatch extremely quickly because the flow of water can be adjusted quickly, often in seconds.
- Medium (minutes): Natural gas turbines can ramp up in minutes. Though B.C. doesn't have any, solar thermal power plants can utilize thermal energy storage and dispatch in minutes.
- Slow (hours): These systems include biomass, nuclear, and coal fired thermal and are typically used to provide baseload power as they typically take hours to ramp up or down. Simply, it takes a long time to heat them up or cool them down.

An Intermittent energy source is any source of energy that is not continuously available for conversion into electricity and is outside direct control because the primary energy (i.e.: the water running in the river, the wind blowing) cannot be stored. Intermittent energy sources may be predictable (e.g. solar) but cannot be dispatched to meet the demand of an electricity system (e.g. solar at night).

In an electricity system, Intermittent sources are used to displace storable primary energy. In B.C., when run-of-river power is available, BC Hydro can "shape and firm" the power coming into the transmission system by turning off or down the water flowing out of the reservoir and into the generators at any or all of its storage dams, subject to there being storage space available in its reservoirs. That is, BC Hydro takes the Intermittent and uncertain generation from run-of-river, wind and solar IPPs and blends it with the Firm and dispatchable power from the storage dams to increase the value to the domestic system, or the export value, of the IPP power.

10) Value of Green Power

The US Environmental Protection Agency defines the following types of power:

> **Conventional power** includes the combustion of fossil fuels (coal, natural gas, and oil) and the nuclear fission of uranium. Fossil fuels have environmental costs resulting from mining, drilling, or extraction, and emit greenhouse gases and air pollution during combustion. Although nuclear power generation emits no greenhouse gases during power generation, it does require mining, extraction, and long-term radioactive waste storage.
>
> **Renewable energy** includes resources that rely on fuel sources that restore themselves over short periods of time and do not diminish, including the sun, wind, moving water, organic plant and waste material (eligible biomass), and

the earth's heat (geothermal). Although the impacts are small, some renewable energy technologies can have an impact on the environment. For example, large hydroelectric resources can impact fisheries and land use.

Green power is a subset of renewable energy and represents those renewable energy resources and technologies that provide the highest environmental benefit. The US Environmental Protection Agency defines green power as electricity produced from solar, wind, geothermal, biogas, eligible biomass, and low-impact small hydroelectric sources. Customers often buy green power for its zero emissions profile and carbon footprint reduction benefits.

The Environmental Choice Program was established by Environment Canada in 1988. It is an ecolabelling scheme that covers more than 300 categories of products to help consumers identify services/products which are less harmful to the environment. The Environmental Choice logo provides customers with assurance that the products and services bearing the logo meet stringent environmental standards that have been verified by a third-party auditor. While founded by the Canadian Government, the program is now well-known worldwide.

The EPAs from the 2010 Clean Power Call transferred all the green attributes of the project to BC Hydro.

The summary report on the 2010 Clean Power Call issued by BC Hydro states:

"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 in most jurisdictions since it no longer has any associated environmental benefits.*

...

- *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."*

Clean/Green power is a broadly supported initiative. In the US, programs are called a "Renewable Portfolio Standard." This sets a requirement to secure rights to a particular quantity of eligible renewable energy by a particular date in time. The form of power that is "eligible" is defined by the individual jurisdictions.

Once the certified Green Power is absorbed in the BC Hydro system it is indistinguishable from all the other power in the system. The industry has developed a system to deal with this issue by tracking the production and consumption of green power with a "Renewable Energy Certificate." Certificates are tracked through a system called "WREGIS" that is similar to the land title tracking system.

In theory, if BC Hydro holds an assignment of the environmental attributes for an IPP, it can "credit" those rights to customers wishing to make a "green statement", or meet a green procurement requirement. This is not commonly done within the province for local customers. Today, the economic value of renewable power is recovered through export. Some jurisdictions in the US are prepared to pay a premium over the market value of uncertified power.

Some jurisdictions (notably California) are moving to restrict the importation of power that is not green certified for their state. California has passed a law requiring 60% of its electricity to be from qualifying renewable sources by 2030 and 100% of its electricity to be from "clean sources" (zero carbon) by 2045. Overlapping definitions of green/clean in competing jurisdictions can be confusing. Even if some of the power purchased from IPPs is not considered "renewable" it may still be considered "clean" and, as such, marketable as "zero carbon."

It is important to note that any incremental revenue that can be returned by the export market is simply a contribution to fixed costs. It would not be sufficient to justify BC Hydro's purchase of new renewable capacity.

Powerex sees a premium in jurisdictions with Renewable Portfolio Standards but only for B.C. resources that are considered eligible by those jurisdictions. While most resources in B.C. are considered "zero carbon", only wind has qualified under the renewable procurement mandate in California to date. These premiums apply to a very small subset of the energy delivered into California and vary from a few dollars up to $15-18/MWh.

11) Planning

1. Load and Energy Planning

BC Hydro estimates the load it will be required to supply, being the power its ratepayers (residential, commercial and industrial) will use. Load planning considers conservation and other demand side actions that could moderate future load demands. To respect that it takes 5+ years to plan, permit and construct most projects, load projections need to run 20 years into the future to give as much lead time as possible. The load plan provides both an estimate of the average energy and the peak energy (highest energy demand) required to meet future load.

2. Capacity and Resource Planning

Based on the load and energy plan, BC Hydro considers the generating capacity of its assets, IPP portfolio and the estimated reasonable level of electricity it can produce over the year from those resources.

The generating capacity of the resources available to BC Hydro need to be capable of meeting the peak energy level indicated in the load and energy plan. The reasonable level of Firm energy that should be available from those resources must be capable of meeting the average energy level in the load and energy plan.

3. Resource Plans

BC Hydro's Resource Plans outline its long-term plan to meet the future electricity demand in B.C. The most recent one was the Integrated Resource Plan, filed with the Government in 2013.

The plan compares the load and energy to the capacity plan to identify any point where capacity is projected as insufficient to meet load. When BC Hydro notes an imbalance between projected load and the capacity and energy available from its resources, BC Hydro has four options:

i. increase demand side management activities to reduce projected load;

ii. increase internal generating capacity by constructing additional generating assets or increasing the generating capacity of existing assets;

iii. trade in the market to buy imported energy to meet expected generation shortfalls; and/or

iv. purchase energy from IPPs.

In the past, the Resource Plan would propose a combination of the four actions to ensure the required future capacity comes into balance with projected load. Prior to the current IRP, the Resource Plan was submitted to the BCUC for approval: BC Hydro's 2008 Long-Term Acquisition Plan (LTAP) was filed with the BCUC in June 2008.

As this report will discuss, Government directed changes to the parameters that drive BC Hydro's energy planning, creating the appearance that more energy was required. Government policies then resulted in BC Hydro being unable to add internal generating capacity or to rely on trading in external markets to buy the energy required to meet domestic needs (eliminating options ii and iii). As BC Hydro always tries to optimize demand side actions, the only option left available to BC Hydro to meet the new load levels projected was to acquire large volumes of additional IPP energy.

12) Industry Environment leading up to IPP Purchases

Starting in the late 1970s, there was a move internationally to facilitate independent power generators connecting to an open and accessible grid.

In 1978, the US passed the Public Utilities Regulatory Policies Act that started the industry on the road to restructuring. This is one of the first laws that began the deregulation of energy companies. The Act broke the previous monopoly in the generation function by enabling non-utility generators to produce power for use by customers attached to a utility's grid. The Act also promoted energy conservation (reducing demand) and the greater use of domestic and renewable energy (increasing supply).

The law forced electrical utilities to buy power from other more efficient producers, such as cogeneration plants, if that cost was less than the utility's own "avoided cost" rate to the consumer.

Ronald Reagan's first executive order in 1981 eliminated price controls on oil and natural gas. Production soared and the price of oil declined by more than 50%.

Starting in 1979 in the United Kingdom, Margaret Thatcher implemented two new policies: environmental protection and deregulation. While some debate the point, many credit Thatcher as the first significant world leader to advocate for environmental concerns and the need to control greenhouse gases. She privatized British Petroleum and state-owned assets involved with gas, water and electricity, and deregulated gas and electricity monopolies.

Directions and the Development of the IPP Portfolio

13) Changing Directions

Prior to 1987, the B.C. Government supported public ownership of key generation and transmission assets, with the belief that this approach could drive economic growth through lower and more predictable energy costs for all ratepayers.

In 1987, the Government recognized shifts in the industry and introduced a new Chair and CEO to lead BC Hydro's response to these changes. The Province wanted BC Hydro to start increasing capacity and to position itself for export and trading opportunities that seemed to be developing.

In line with changes seen in the US, BC Hydro was told to consider accessing power from private producers, and to give those projects access to the grid to facilitate direct export sales.

To understand how government policy influenced BC Hydro's development of its IPP Portfolio over time, a series of graphs are presented in this report. These graphs illustrate the progression of procurement processes that BC Hydro used to acquire power and the prices paid for that power as compared to two significant benchmarks:

- Market prices, as represented by the average annual Mid-C price.
- Cost of energy generated by BC Hydro Heritage Assets. Since records for the cost of energy from Heritage Assets are not readily available before 2004, costs before 2004 have been extrapolated backwards from the estimated costs in 2004.

When viewing these graphs, readers should be aware that these charts are indicative in nature:

- The data has been smoothed to remove anomalies. An example of an anomaly is where a project reaches commercial operation near the end of a fiscal year, and the average price for delivered energy is heavily influenced by the Time of Delivery adjustment which pays a higher price during winter months.
- To simplify the graphs and to respect commercially sensitive information for individual projects (where there are a small number of projects in a given call):
    - A representative sample of BC Hydro's call processes has been included in the graphs.
    - Similar calls have been consolidated into a single line.
- These graphs reflect the indicative average cost for delivered energy (as opposed to the gate price of the EPAs).
    - The graphs include the impact of energy that has been deemed to be delivered, facility curtailment and turn-downs, and both Firm and non-Firm energy.
    - The data is influenced by a number of factors, such as:
        - Energy profile of the projects, as a result of the Time of Delivery adjustments.
        - Projects reaching commercial operations at various points in the year.
        - Facility curtailment and turn-down for biomass projects, in which BC Hydro pays a reduced price during the turn-downs but a higher average cost for delivered energy results.
    - The graphs do not reflect differences in the value of the energy delivered (e.g., energy delivered during freshet vs. hourly firm energy delivered in the winter).

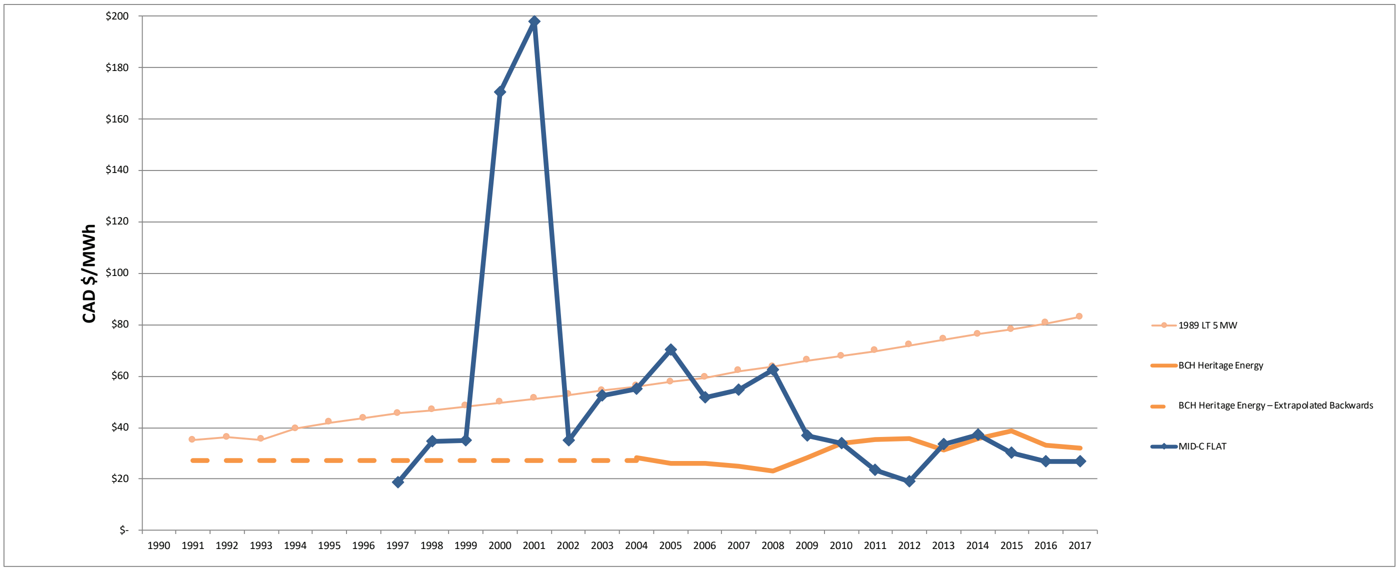


Figure 2: BC Hydro IPP Portfolio History Graph #1–1989 LT 5 MW Call

The 1989 LT (Less Than) 5 MW Request For Proposals (RFP) was BC Hydro's first call process and was originally intended for projects that were less than 5 MW in capacity. However, projects awarded EPAs under this process ranged from less than 100 kW to close to 17 MW in capacity. The RFP included set prices and annual escalation set at 3%, though actual EPA awards may have varied from these terms. Twelve EPAs were awarded through this RFP, involving a total of 80 MW and 390 GWh per year awarded.

Following the 1989 LT 5 MW RFP, BC Hydro continued to acquire power from IPPs at a modest rate into the early 2000s with the resulting EPAs being largely driven by business cases with oversight for project approval provided by the BCUC.

The 2001 LT (Less Than) 40 GWh call resulted in EPAs with 21 IPPs, 12 of which are still active.

The 2001 GT (Greater Than) 40 GWh call resulted in EPAs with 3 IPPs, all of which are still active.

In the early 2000s, Government believed that economic growth could be enabled by facilitating private investment. BC Hydro's investment in its own assets was effectively capped and the Province established a clear expectation that new generation capacity would be met by the private sector. Government also focused on the environment, including a move to energy conservation and clean power generation, initiatives which continue today.

In 2001, the energy crisis resulted from an apparent energy shortage in the US and particularly in California. The resulting high rates were viewed as an exciting business opportunity for B.C. to evolve into an energy export powerhouse. The vision was to grow IPP capacity and give IPPs access to the grid, so that they could enter into export deals either directly or through Powerex.

An association of independent power producers formed to support of this approach. This association continues today as Clean Energy BC.

Government made three important pronouncements in support of this approach: the 2002 Energy Plan, the 2007 Energy Plan and the 2010 *Clean Energy Act*. Based on the Government's anticipation of a growing market, BC Hydro was directed to move in the direction of IPPs, with alacrity.

However, things were not as they originally appeared. Systemic lack of new generation, low water in the West and a poorly designed market in California made the Western market vulnerable to a market manipulation fraud perpetrated by Enron. The result was a sharp increase in power rates in the US. Once the Enron scandal broke, rates crashed back to normal historic levels. The energy crisis ended abruptly with prices crashing from highs in the range of $200 per MWh back to a more normal $30 per MWh range.

Meanwhile, the transmission corridor from Washington to California was already full. Powerex was having issues finding delivery capacity to meet its own internal trading needs, let alone the delivery capacity to support direct IPP sales to the US. Clearly, the export vision would require a material increase in transmission capacity, which would be a huge, expensive project and one that would take years to negotiate and construct.

At that time, Burrard Thermal, BC Hydro's gas-fired generating facility had just been upgraded with $150 million in new catalytic converters, arguably making it as clean or cleaner than the gas generation California relies upon today. Though Burrard Thermal emits greenhouse gases, it was considered at the time to be clean enough to run for another 10 years.

As of December 2001, BC Hydro had sufficient clean resources online to meet the future demand forecast at that time. BC Hydro was not desperate for additional power.

Given the apparent uncertainties in the market and the adequacy of current capacity, the prudent business decision at the time would be to advance IPPs slowly and to wait for developments in the export market. This would maintain B.C.'s clean power profile and would continue the economic development initiatives embedded in the IPP projects, albeit at a modest pace.

Unfortunately for the ratepayers of today, that was not the direction BC Hydro received from Government. Government held to its direction and released policies in the 2002 and 2007 Energy Plans that had the predictable effect of overstating the demand for electricity in B.C. to create an apparent urgent need to accelerate IPP projects.

14) 2002 Energy Plan

The 2002 Energy Plan provided policy direction to BC Hydro to purchase its energy from IPPs rather than generating energy itself. One objective of the 2002 Energy Plan was to foster new sources of power generation by offering better access to transmission infrastructure. Government believed the industry was moving towards increased independence of transmission through the development of regional transmission organizations. The 2002 Energy Plan directed BC Hydro to separate the management of its generation assets from the management of its transmission assets.

In 2003, BC Hydro created the BC Transmission Corporation (BCTC). BCTC managed the transmission assets held by BC Hydro under contract. Those interviewed for this report believed there were service and functional duplications and overlaps between BCTC and BC Hydro.

By 2010, it was apparent that regional transmission organizations were not developing and the movement towards the independence of transmission was halted. The 2010 *Clean Energy Act* integrated BCTC back into BC Hydro. Current BC Hydro executives estimate that the cost of duplications for seven years, and the cost to create and dissolve BCTC would be in the range of $250 million.

15) 2003 Green Power Generation Call

BC Hydro announced its 2002/03 Green Power Generation procurement process on October 30, 2002. Seventy project proposals were submitted; ultimately 16 projects met evaluation criteria, were within the required price cap and were awarded an EPA.

The projects were required to be operational by September 2006 and projected to generate approximately 1,800 GWh per year.

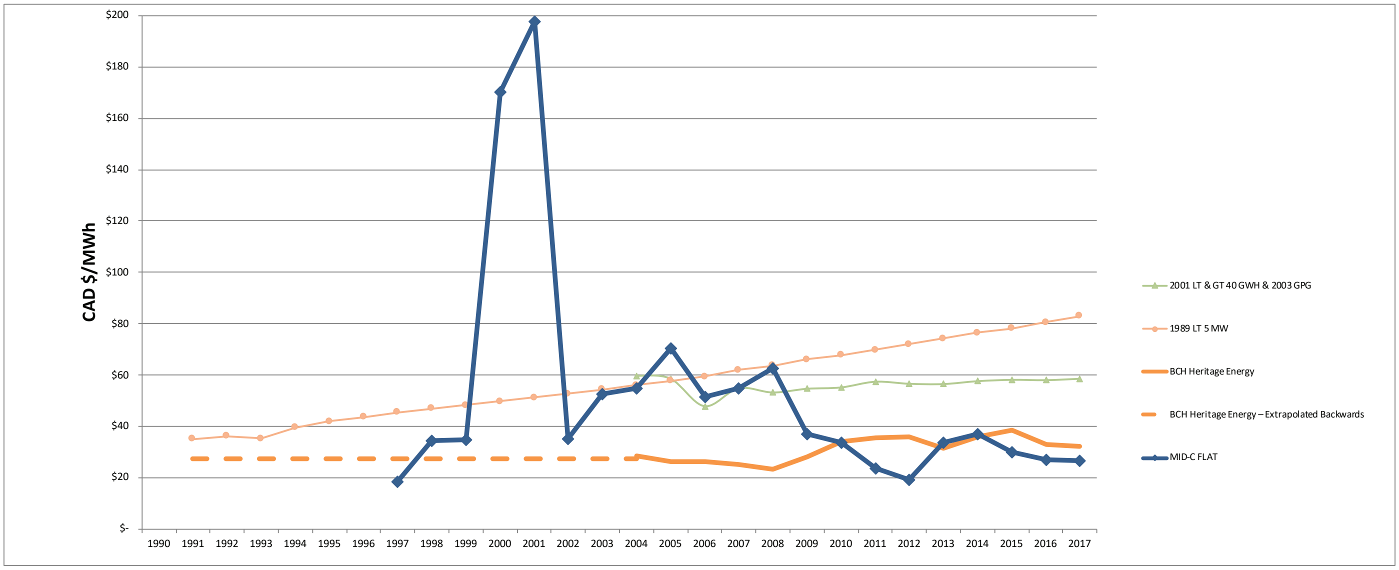


Figure 3: BC Hydro IPP Portfolio History Graph #2–2001 LT & GT 40 GWh, 2003 GPG

Figure 3 includes the indicative cost of delivered energy for EPAs from the following calls:

- 2001 Less Than 40 GWh Call
- 2001 Greater Than 40 GWh Call
- 2003 Green Power Generation Call

16) 2006 Open Call for Tenders

On December 8, 2005, BC Hydro issued an open call for power for approximately 2,500 GWh per year of Firm energy from large projects and approximately 200 GWh of energy from small projects.

On April 7, 2006 BC Hydro received bids from 37 proponents for 53 projects. The projects submitted include electricity generation from both small and large facilities, and included hydro, wind, biomass and coal resources. Tendered projects offered capacity of approximately 1,800 MW and Firm energy totalling approximately 6,500 GWh per year.

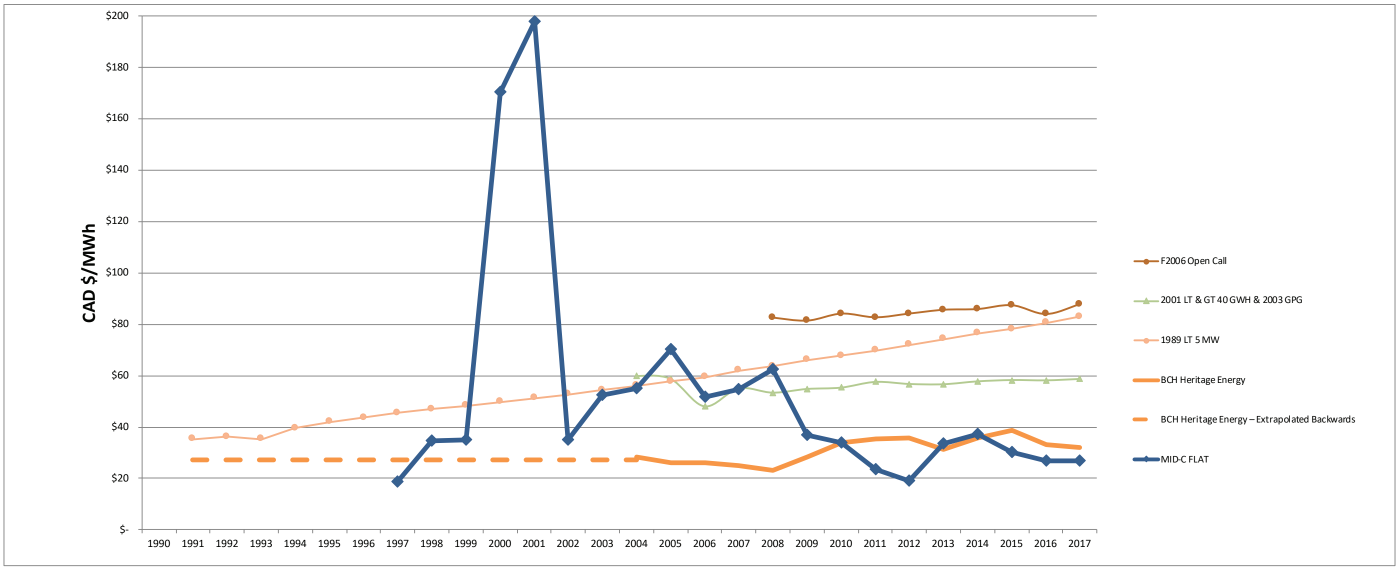


Figure 4: BC Hydro IPP Portfolio History Graph #3–F2006 Open Call

17) 2006 Integrated Electricity Plan

BC Hydro publishes Resource Plans which outline the utility's long-term plan to meet anticipated customer electricity needs. These Resource Plans are either submitted to Government or to the BCUC for approval.

On March 29, 2006, BC Hydro filed the 2006 Integrated Electricity Plan (IEP), including its Long-Term Acquisition Plan (LTAP), with the BCUC. On May 11, 2007, the BCUC released its decision on the 2006 IEP/LTAP application.

The 2006 IEP is BC Hydro's contextual document that outlines how BC Hydro plans to meet customer electricity needs for the period of Fiscal 2006 to Fiscal 2025. It provided the analysis for an acquisition strategy that informed the LTAP, an action plan for the 10-year planning period from Fiscal 2006 to Fiscal 2015. The 2006 IEP was intended to realize BC Hydro's purpose of providing reliable low-cost power, while considering key environmental and social issues.

18) 2007 Energy Plan–Vision for Clean Energy Leadership

With the 2007 Energy Plan, Government set 55 objectives and statements of policy direction with respect to energy and BC Hydro, with "green/clean" and "self-sufficiency" as the primary themes that would drive IPP purchases forward:

- **Achieve electricity self-sufficiency by 2016.**
- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**
- **Government supports BC Hydro's proposal to replace the Firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.**

The press release further underscored the importance of self-sufficiency, insurance and clean power:

"We are now dependent on other jurisdictions for up to 10 per cent of our electricity supply. BC Hydro estimates demand for electricity to grow by up to 45 per cent over the next 20 years."

"BC Hydro must acquire an additional supply of "insurance power" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports."

"We are looking at how we can use clean alternative energy sources, including bioenergy, geothermal, fuel cells, water-powered electricity, solar and wind to meet our province's energy needs."

"Even though it could generate electricity from Burrard Thermal, BC Hydro imports power primarily because the plant is outdated, inefficient and costly to run. However, Burrard Thermal still provides significant benefits to BC Hydro as it acts as a "battery" close to the Lower Mainland, and provides extra capacity or "reliability insurance" for the province's electricity supply. It also provides transmission system benefits that would otherwise have to be supplied through the addition of new equipment at Lower Mainland sub-stations.

This was the start of Government's direction of BC Hydro's energy planning process. BC Hydro was instructed to be self-sufficient (eliminate relying on the market to meet demand) and then to overbuy generating capacity and energy from IPPs to ensure surplus "insurance power" was available and to make up for the Firm energy that would be lost from Burrard Thermal.

BC Hydro had policies covering how energy and capacity projections would be undertaken, which had been in place and proven effective. The 2007 Energy Plan confirmed Government planned to direct which parameters BC Hydro would use in its projections of future need and intended to direct BC Hydro to buy well in advance of that future need:

"Government will set policies to guide BC Hydro in producing and acquiring enough electricity in advance of future need."

Further, the 2007 Energy Plan directed BC Hydro to buy power from Intermittent generation sources, notwithstanding there is a cost to BC Hydro to shape and firm that power for use in the system.

- **Ensure the procurement of electricity appropriately recognizes the value of aggregated Intermittent resources.**

"As part of The BC Energy Plan, Government will work with BC Hydro and parties involved to continue to improve the Call for Tender process for acquiring new generation. Fair treatment of both buyers and sellers of electricity will facilitate a robust and competitive procurement process. Government and BC Hydro will also look for ways to further recognize the value of Intermittent resources, such as run-of-river and wind, in the acquisition process–which means that BC Hydro will examine ways to value separate projects together to increase the amount of Firm energy calculated from the resources."

The 2007 Energy Plan also provided clear direction to BC Hydro as to how it would price projects through the Standing Offer Program. Pricing would be based on the prices paid in BC Hydro's the most recent call for power (i.e. not the value for power as evidenced by the prices on the Mid-C export market). The new policy guided BC Hydro to issue an open-ended call with a set price, irrespective of its projection of need:

- **Establish a standing offer for clean electricity projects up to 10 megawatts.**
- **Make small power part of the solution through a set purchase price for electricity generated from projects up to 10 megawatts.**

> *"This policy will direct BC Hydro to establish a Standing Offer Program with no quota to encourage small and clean electricity producers. Under the Standing Offer Program, BC Hydro will purchase directly from suppliers at a set price."*
>
> *"The price offered in the standing offer contract would be based on the prices paid in the most recent BC Hydro energy call. This will provide small electricity suppliers with more certainty, bring small power projects into the system more quickly, and help achieve Government's goal of maintaining a secure electricity supply. As well, BC Hydro will offer the same price to those in BC Hydro's Net Metering Program who have a surplus of generation at the end of the year."*

In addition to establishing the Standing Offer Program, the 2007 Energy Plan directs BC Hydro to support the forestry industry through a bioenergy strategy:

- **Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.**
- **Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.**

> *"BC Hydro will issue a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation."*

The 2007 Clean Energy Plan made it clear that Government policies would drive the business decisions and actions at BC Hydro and would define the strategies available to BC Hydro in the discharge of its mandate.

Control over many aspects of procurement of new generation capacity was shifting away from BC Hydro to Government. Based on the information available, it is uncertain where in Government BC Hydro was to look for that direction, though BC Hydro was likely left to assume the direction would come from the Minister responsible, either directly or through the Ministry at the Minister's direction.

19) Standing Offer Program 2008

The Standing Offer Program (SOP) began in 2008 to meet the policy direction from the 2007 Energy Plan that BC Hydro should "make small power part of the solution through a set purchase price for electricity generated from projects up to 10 megawatts."

The 2008 SOP was designed to facilitate the development of clean electricity projects while alleviating the administrative burden for small projects to bid into BC Hydro calls. The SOP offered set pricing based on the results of the most recent call. Proposals for non-Firm energy projects with a nameplate capacity (projected capacity) of greater than 50 kW but not more than 10 MW were eligible. The SOP was created without an overall volume quota.

The agreements as part of the 2008 SOP were filed with the BCUC under section 71 of the *Utilities Commission Act* and accepted by the BCUC as being within the public interest. However, when the *Clean Energy Act* came into effect, section 7(h) exempted SOP agreements from section 71 of the *Utilities Commission Act*. This meant that on a go-forward basis, new SOP agreements or amendments to existing agreements no longer needed to be filed with the regulator.

In 2013, the size limit for individual projects was increased from 10 MW to 15 MW and the total available volume from 50 GWh/year to 150 GWh/year.

BC Hydro stopped taking any applications under the SOP in August 2017, since the volume for 2017, 2018 and 2019 was fully subscribed. In March 2018, BC Hydro announced it would not issue any EPAs under the SOP pending the outcome of the Comprehensive Review of BC Hydro, with the exception of five specific projects that are part of Impact Benefit Agreements for First Nations and/or that have significant First Nations involvement.

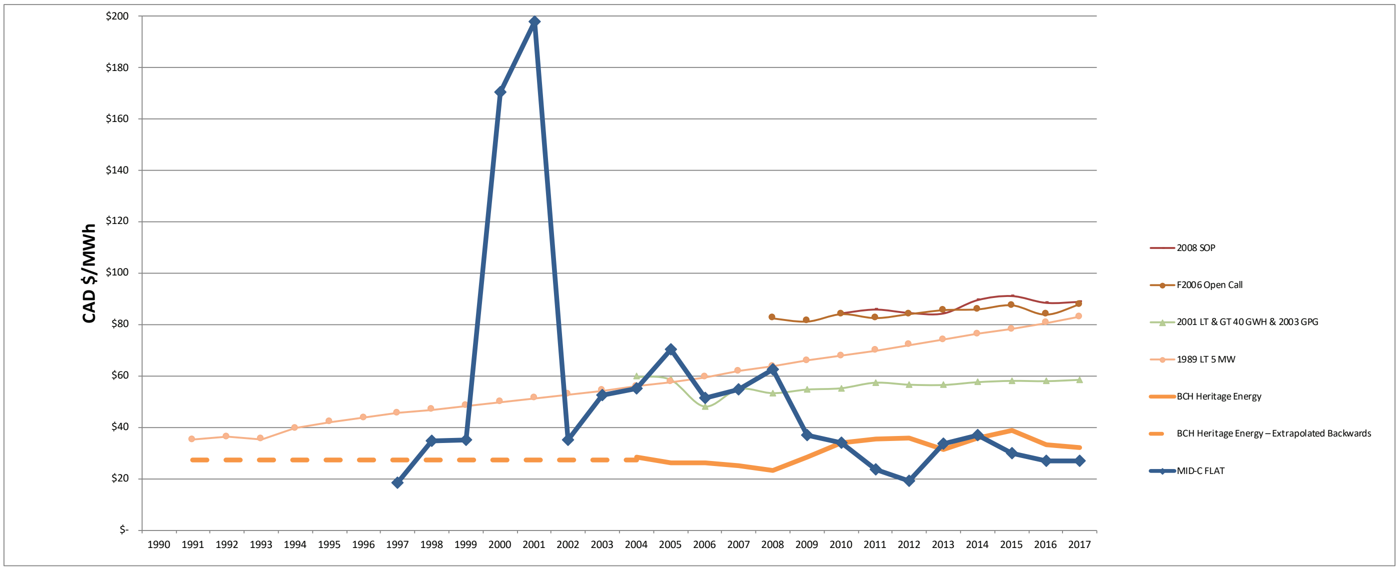


Figure 5: BC Hydro IPP Portfolio History Graph #4–2008 SOP

20) BCUC Special Direction No. 10 June 26, 2007

In support of the 2007 Energy Plan, Government issued Special Direction #10 to BCUC in 2007 directing that it approve BC Hydro plans and activities required to achieve energy self-sufficiency by 2016, with "insurance" capacity above the level of self-sufficiency of at least 3,000 GWh to be achieved by 2026.

Special Direction #10 also directed the BCUC that the generating capacity necessary to meet the self-sufficiency mandate must be "solely from electrical generating facilities within the Province."

Special Direction #10 constrained the BCUC with the following condition:

> "In Considering a biomass contract under section 71 (2) of the Act, that commission may not find that a biomass contract is not in the public interest solely by reason of the factor described in section 71 (2) (d) of the Act, ..."

The *Utilities Commission Act* states in part in Article 71 (2) that

> "The commission may make an order under subsection (3) if the commission, after a hearing, determines that an energy supply contract to which subsection (1) applies is not in the public interest."

and in (2.1) (d) that

> "In determining under subsection (2) whether an energy supply contract filed by a public utility other than the authority is in the public interest, the commission must consider....(d) the interests of persons in British Columbia who receive or may receive service from the public utility..."

Article 4 continues with a direction that the BCUC be guided in its consideration of biomass projects by the fact that these projects will reduce greenhouse gases, will contribute to diversity of BC Hydro's energy supply, and will assist BC Hydro in meeting its capacity targets.

In sum, Government effectively directed that the BCUC could not find that Bioenergy Phase 2 Call EPAs were not in the public interest. Government was certainly concerned that the Bioenergy Phase 2 Call EPAs would not be approved by the BCUC on their own merit. Government was not clear as to which attribute typical of biomass projects it was concerned would lead to rejection of the contracts by the BCUC.

Special Direction 10 also illustrates the economic impact of the self-sufficiency mandate. It provided direction that all new capacity must be "solely from electrical generating facilities within the Province". The unwritten corollary is that BC Hydro is specifically directed on a planning basis not to rely on power imported through the Mid-C Hub to meet projected load. At the time, it was projected that importing power at the Mid-C price would have been less expensive that the prices paid to biomass producers and other IPP producers.

BC Hydro, a Commercial Crown, had been told by the Government not to incorporate the cheaper power into its plans. Given its options had been limited by Government, BC Hydro procured the most cost-effective projects available from this call. 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." True, after eliminating the more cost-effective options, a competitive market-based process should, in most circumstances, be accepted as persuasive evidence of the cost-effectiveness of the resultant successful bid (from within the options Government left available for BC Hydro to choose from).

21) 2008 BIOENERGY PHASE I Call, 2010 BIOENERGY PHASE 2 Call RFPs and Integrated Power Offer

The Bioenergy Phase I Call and Phase 2 Call supported the Province's 2007 Energy Plan and 2008 Bioenergy Strategy to help mitigate impacts from the provincial mountain pine beetle infestation.

The Bioenergy Phase I Call RFP process, launched in 2008, approved EPAs for slightly less than 15% of the energy in the responding proposals. In June 2008, BC Hydro received 20 proposals, representing 4,100 GWh/year of Firm energy.

The Phase 2 Call focused on stand-alone biomass projects and intended to help mitigate impacts from the provincial mountain pine beetle infestation. It was launched on May 31, 2010 and resulted in the award of four EPAs in August 2011.

The RFP for Phase 1 offered contract term and COD flexibility (both initial COD and the opportunity for phased COD) and hourly and seasonally Firm energy options. BC Hydro utilized the discretion inherent in an RFP process to negotiate price as well as both essential variations and value variations with proponents. The Bioenergy Phase 2 Call RFP process was modified from previous acquisition processes (including the Clean Power Call and Bioenergy Phase 1 Call) in order to make improvements, including to reduce submission costs incurred by unsuccessful proponents to the call.

The RFP stated that BC Hydro would not award EPAs for projects with a final levelized energy price (reflecting inflation and other adjustments) above the $150/MWh ceiling price.

The cost-effectiveness of the awarded EPAs for the Bioenergy Phase 2 RFP was demonstrated by the following three benchmarks:

- Competitive nature of the RFP process;
- Comparison to other recent BC Hydro power calls; and
- Comparison to energy prices in other North American jurisdictions.

Presumably, BC Hydro did not compare the cost-effectiveness of the awarded EPAs to the value of energy in the Mid-C market as Government direction had eliminated a reference to value from the procurement strategy. It is also likely that BC Hydro anticipated that any reference to the Mid-C market price would produce an unfavourable result.

BC Hydro Call Process	Completion of EPA Awards	Lowest Levelized AFEP ($/MWh)	Highest Levelized AFEP ($/MWh)	Weighted Average Levelized AFEP ($/MWh)
(All prices adjusted to January 2010 dollars)				
Bioenergy Phase 1 RFP	December 2008	112	119	116
Clean Power Call RFP	July 2010	108	137	127
Bioenergy Phase 2 RFP	August 2011	112	121	115

Table 5-1: Comparison to Recent BC Hydro Calls

The Integrated Power Offer (IPO) was designed to support the delivery of integrated offers to industrial customers that optimize all cost effective electricity-related opportunities at a customer site. On June 17, 2009, Natural Resources Canada (NRCan) announced the "Pulp and Paper Green Transformation Program" (GTP) aimed at supporting innovation and environmentally friendly investment in areas such as energy efficiency and renewable energy production. Up to $1 billion was set aside to assist Canadian pulp and paper producers, creating an estimated $300 to $500 million in potential capital investment in B.C.

As a result, BC Hydro fast-tracked the introduction of the "IPO for its pulp and paper customers affected by the GTP so that it could influence project selection and ideally have agreements in place in advance of pulp and paper companies submitting their proposals to the federal government.

Through the IPO, BC Hydro entered into seven EPAs with pulp and paper customers, all of which are still in operation.

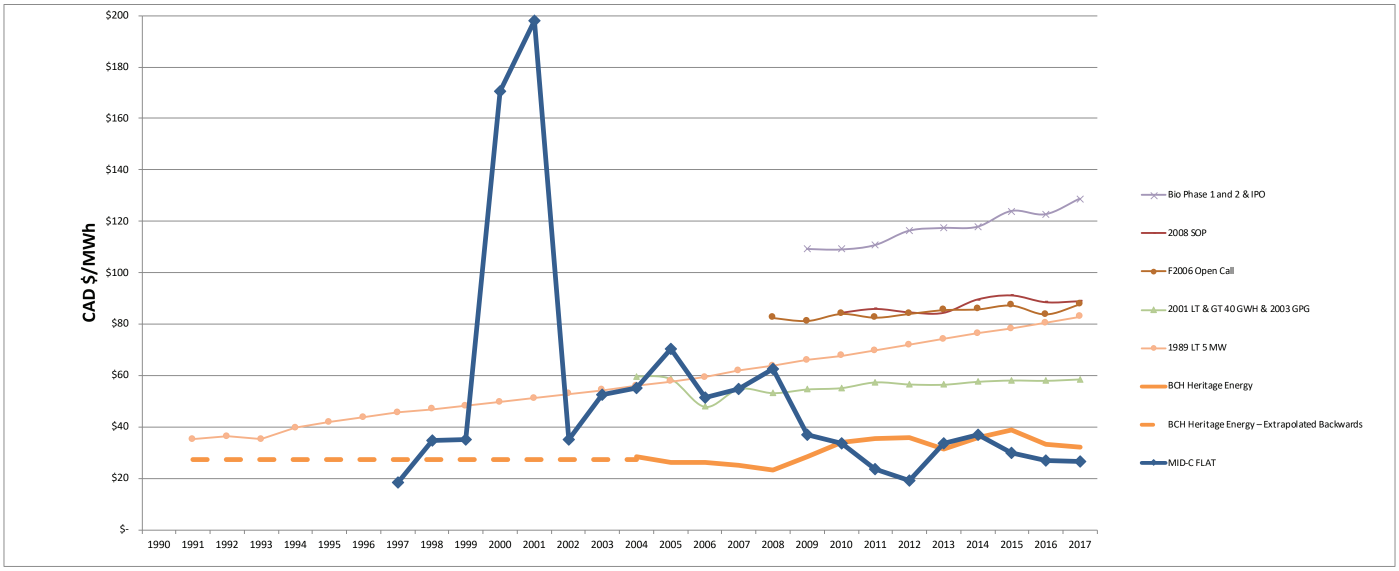


Figure 6: BC Hydro IPP Portfolio History Graph #5–Bio Phase 1 and 2 & IPO

Figure 6 includes the indicative cost of delivered energy for EPAs from the following calls:

- Bioenergy Phase 1 Call
- Bioenergy Phase 2 Call
- Integrated Power Offer

In Figure 6, it should be noted that the increasing average cost for delivered energy is due to: new projects coming on line with higher prices; escalation in contract prices; and increased use of turndown provisions (which saves costs but increases the average cost of delivered energy).

It should be noted that biomass generation provides a higher quality of energy to BC Hydro because it can be dispatched off when not required (e.g., during freshet), it provides firm energy during winter months (when BC Hydro needs the energy the most), it is not an Intermittent energy resource (i.e., is not dependent on weather or other factors) and it can provide system reliability benefits.

22) Market Movement

With speed comes risk. The energy market has volatility that correlates to the price of natural gas. Further, the major investments in green energy technology made post-2000 were starting to lead to breakthroughs that improved the cost/energy profile of wind and solar implementations.

In June 2008, the 10-year natural gas price at Henry Hub was at a significant high of US$11/mmbtu and annual price of Mid-C was in the C$60-65/MWh range. By June of the following year, the long-term price of natural gas had fallen to US$7.50/mmbtu and annual Mid-C into the C$40/MWh range. By 2010 the annual Mid-C fell into the C$25/MWh range. By late 2018, the long-term price of natural gas at Henry Hub Nymex had fallen to roughly US$3/mmbtu.

Since 2009, Mid-C has moved in the C$20-$40/MWh range and after 2014 settled in slightly lower than C$30/MWh, with natural gas at US$3/mmbtu.

The Ministry of Energy, Mines and Petroleum Resources confirms its analysts knew in early 2009 that new production volumes from shale gas and fracking were coming into the market and gas prices should be expected to settle, bringing the Mid-C price down with them. Ministry staff advise this knowledge was passed on to Government on a number of occasions, but supporting documentation was not located. BC Hydro staff confirm they also provided similar information to the Government, but again documentation was not located.

Subtler, but still important, are the changes in the demand from industry in B.C., following the financial crisis of 2008. Large industrial customers closed their doors, including the Methanex petrochemical plant and four pulp mills: Catalyst (Elk Falls), Western Pulp (Squamish), Abitibi, and Eurocan Pulp. Load losses aggregated to about 3,500 GWh or 6.4% of system load. About 60% of the total decline in load was due to the closure of the Catalyst (Elk Falls) pulp mill.

These sorts of changes are likely visible only after they aggregate and it becomes apparent that alternate industrial customers are not entering the market to take up the available energy.

In the face of an energy market correction and with declining industrial load, the Government held to its vision. On November 3, 2009, the Premier spoke to the annual conference of the Independent Power Producers Association of BC to announce a sweeping, fundamental review of energy policy in British Columbia. The stated intention was to make B.C. an international leader in clean power development–both for this province and for export to markets including the United States and Alberta–to attract and strengthen the independent power sector in B.C.

The Premier noted in that same speech that IPPs had been frustrated at times by protracted power sales contract negotiations with BC Hydro, which made it challenging to attract investor support for projects. They had also been a target for some environmental and public policy based non-Government organizations–and even by BC Hydro's large-scale industrial customers–for allegedly driving up the cost of electricity supply.

The Premier made it clear that Government was steadfast in its support for expansion of independent power supply.

> "We have enormous resources in British Columbia and those resources allow us to provide not just the people that live in this province with green and clean, low-carbon power, it allows us to expand our horizons to build an economy based on green, clean low-carbon power–and we have to do that together, and that means we have to do that with the independent power producers of British Columbia"

The Premier confirmed the green energy advisory body announced in the August 2009 Throne Speech would review the regulation of BC Hydro, expanded electricity export opportunities, community engagement in the development of new, private sector power and BC Hydro's procurement regime to enhance clarity, certainty and competitiveness in promoting clean and cost-effective power generation. The advisory body would report out by January 2010.

This is an important point in the chronology. Sections 31 and 32 quantify the impact that Government's directions had on BC Hydro's energy planning process. Those sections conclude that BC Hydro was ultimately directed to buy an incremental 8,500 GWh/year of energy to fill a projected energy shortfall that only appeared to exist due to the Government's direction as to the parameters BC Hydro should use in its energy planning processes. From the records available, it is not possible to confirm where in relation to the 8,500 GWh target BC Hydro landed. However, what is clear is that BC Hydro operated with the intent to purchase the additional energy it had been directed to buy.

The aggregate contracted energy of all continuing EPAs executed after December 21, 2009 is approximately equal to 8,500 GWh/year. While we cannot be certain that each of these particular EPAs were part of the response to the direction to buy, it is clear that BC Hydro is currently in an energy surplus situation which will continue into the 2030s.

By this time, Government had been advised by both Ministry and BC Hydro analysts that the market had changed; Government did not heed the warning. Government could have and should have stopped the IPP procurements. If they had stopped, the total impact to BC Hydro ratepayers would have been avoided.

The green energy advisory body included four task force committees that reported to the Cabinet Committee on Climate Action and Clean Energy. That Cabinet Committee, which included the Premier, the Environment Minister and the Energy Minister, was exempt from disclosure under the Freedom of Information and Protection of Privacy Act by Regulation 311/2010. This made the recommendations and advice from the four task force committees to Cabinet also exempt.

An industry spokesperson was quoted as saying,

> "The short timeline shows that they are committed to sending the right signals to the investment community, which is incredibly important because other jurisdictions are beating us to the punch. I was also really relieved to see that the Government is committed to reviewing the environmental guidelines around approval and acceptance [of IPP power projects] and to strengthening the criteria for ensuring what projects happen and what don't."

Government did not react until 2013, when BC Hydro's Integrated Resource Plan reversed some of the parameters that Government had introduced for the BC Hydro energy planning processes. This action reduced the appearance of an energy shortfall and would be cited by Government as its reaction to the advice from the Ministry and from BC Hydro it had received four years earlier. Though this appears to be a response to that advice, Section 28 below highlights that while Government was attempting to undo the direction it had provided for the energy planning process, it was also increasing project size limits and aggregate quotas for the Standing Offer Program to allow more projects and much larger projects into the program. It is important to note that it typically takes about four years to permit, construct and bring an IPP to commercial operation, so the impact of increasing the number and size of projects would have impacts in the years ahead.

As late as December 2015, Government still continued to pursue a stronger relationship with the industry association, directing BC Hydro and the Ministry to enter into a Memorandum of Understanding with the Clean Energy Association of BC (see Appendix D). As is discussed further in Section 28, this memorandum required BC Hydro to coordinate communications with the industry association and provide the association with information on its policy for EPA renewals and supply forecasts. Furthermore, the memorandum committed BC Hydro to participate in a continuous process of evaluation and improvement of its procurement processes for the acquisition of independent power resources.

Taken as a whole, it would be incorrect to characterize the 2013 response as a real reaction to the dire predictions that Government had received from both the Ministry and from BC Hydro. Rather, actions were taken that had the effect of worsening the problem.

23) 2010 Clean Energy Act

To understand the *Clean Energy Act*, one needs to look back to the 2008 LTAP (Long Term Acquisition Plan).

The 2008 LTAP that BC Hydro presented for BCUC approval dealt with energy acquisitions in the upcoming period, including the development of IPPs and the award of the associated EPAs. One thing considered in the 2008 LTAP was the future Burrard Thermal should play in BC Hydro's capacity plan.

Burrard Thermal was a huge asset capable of generating 900 MW of capacity and 6,000 GWh of energy, or ~10% of the capacity in the whole BC Hydro system. Burrard Thermal is positioned adjacent to the largest load in the system (Lower Mainland). Burrard Thermal is also highly dispatchable (can be easily turned on and off). Burrard Thermal had been upgraded in the 1990s with new catalytic converters; it was never cited by the environmental regulators at the time as a greenhouse gas issue.

Burrard Thermal was used to meet peak winter demand and to smooth load. It was seldom operated for any extended periods and in the time of the BCUC decision, its power generation was in the range of 100-300 GWh/year. Notwithstanding the low generation output of the facility at the time, Burrard was still vital to BC Hydro's planning as it served as a reliable source of emergency power to protect the Vancouver load from disrupted service. At the time of the 2008 LTAP, Burrard Thermal was projected to remain as insurance until the new Interior-to-Lower Mainland (ILM) transmission line came online, which was projected for completion in 2015. ILM would connect the load in Vancouver and Victoria to the generating resources in the Interior.

BC Hydro proposed to the BCUC that Burrard Thermal should be relied on for planning purposes at 900 MW of capacity and 3,000 GWh of energy. Interveners in the regulatory proceeding opposed to IPPs proposed that Burrard Thermal should be included in the energy forecast as running at full capacity producing 6,000 GWh of energy. The BCUC ruled in favour of the interveners on the 2008 LTAP and directed that Burrard Thermal be included in the capacity plan at its full energy potential of 6,000 GWh/year.

The BCUC's role is to protect the ratepayer and to consider the public interest. The BCUC reviewed in detail BC Hydro's IPP portfolio to that point in time and understood the cost pressures BC Hydro would face in the future due to the high prices to be paid to IPPs.

The BCUC would also understand the impact that the self-sufficiency mandate would have on BC Hydro and its procurement of IPP energy. Self-sufficiency eliminated the option of planning to acquire energy from neighbouring markets, which for planning purposes had previously been assumed to provide 2,500 GWh of energy per year in the resource plan. Self-sufficiency also created a new requirement for BC Hydro to provide 3,000 GWh of "insurance" energy per year, in addition to projected demand.

In sum, the self-sufficiency mandate would create an apparent need for an additional 5,500 GWh of energy per year. BC Hydro would then be directed to fill that energy demand with new IPP projects, thereby exacerbating the growing cost pressures at BC Hydro.

The BCUC moved to protect ratepayers by making its own decisions on BC Hydro's energy planning process. Just as Government had changed the basis of energy planning with self-sufficiency to create an apparent need for more IPP energy, the BCUC ruled that BC Hydro should rely on Burrard Thermal in the energy planning process for 6,000 GWh of energy per year. Having Burrard Thermal as a 6,000 GWh/year energy asset eliminated the supply-side gap of 5,500 GWh/year BC Hydro was projecting to meet directives in Government's self-sufficiency mandate. The BCUC declined to support BC Hydro's proposed IPP acquisition targets for the Clean Power Call, since there was no longer a projected need for additional capacity or energy.

The BCUC's response would have eliminated the projected energy deficit and the need for future IPP energy, effectively curtailing the program. Changes to the Energy Planning process are discussed in detail in a Section 31–Direction to Change Energy Planning.

However, the Province made it clear to BC Hydro that it was not to generate power using Burrard Thermal. When interviewed for this report, a BC Hydro staff member with direct knowledge of the situation stated that in response to the instruction received from Government, the CEO of BC Hydro directed the Vice President of Power Generation to personally supervise all activities at Burrard Thermal, including the monthly start-up and test required under the operating permit.

The BC Hydro executive team understood the impact that an immediate closure of Burrard Thermal would have on BC Hydro and ratepayers. The executive drafted a response to Government which the CEO transmitted to Government on September 21, 2009. The email noted BC Hydro's testimony before the BCUC that showed reliance on Burrard for 3,000 GWh would generate $900 million in savings, compared to Burrard Thermal generating at much lower levels. Further if BC Hydro acted as directed and relied on Burrard Thermal for 900 MW of capacity but no energy, it would still need to complete improvements to Burrard to maintain the operating license. These improvements would cost $200-$300 million, with no offsetting revenue.

The CEO was terminated November 4, 2009.

In the typical situation a Minister makes a pronouncement, which is then clarified and amplified by political staff working for the Minister's office. In this case, Government's direction in the 2010 *Clean Energy Act* was clear and detailed, and was announced repeatedly in public forums. While the political staff of the Minister's Office and the senior staff of the Ministry repeated the message, and in some cases supported the development of BC Hydro's response and actions, the review did not encounter any indication that the vision and message was either altered or amplified by those staff. The political operatives and Ministry staff appear to have simply adhered to the vision, as directed by Government.

The 2010 *Clean Energy Act* was passed shortly thereafter, providing in Section 7 that the BCUC would have no further role in the approval of a number of capital projects and initiatives, including the Northwest Transmission Line, Site C, the Bioenergy Phase 2 Call, the Clean Power Call, the Integrated Power Offer, and the Standing Offer Program.

Section 8 directed the BCUC to ensure that BC Hydro's rates allow it to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the overwhelming majority of the IPPs and all other actions BC Hydro was instructed to undertake.

It is worth restating that the BCUC is the regulatory body charged with the task of protecting the ratepayer. In the past, it has approved BC Hydro's Resource Plans, applications on capital projects and rate applications for recovery of BC Hydro's costs from its ratepayers. The *Clean Energy Act* removed the BCUC's project approval role for a long list of significant projects. Given BC Hydro is required to adhere to the mandate and directions it receives from Government, the effect of this change was to move the approval of all the projects into the unfettered control of the Government, without the independent oversight and protection for ratepayers typically provided by BCUC.

The *Clean Energy Act* left the BCUC with the ability to approve BC Hydro's rate proposals, but Section 8 of the Act severely limited that ability. Section 8 required the BCUC to approve rates sufficient to allow BC Hydro to recover all of the costs of many of its energy acquisitions from IPPs that were driven by Government policy–including Bioenergy Phase 2, the Clean Power Call and the SOP–without the ability of the BCUC to approve the EPAs themselves.

The *Clean Energy Act* has an aggressive feel to it that is not typical of legislation. While it deals with many topics, there is certainly a focus on the future role–or lack thereof–of the BCUC in approving Electricity Purchase Agreements with IPPs.

One EPA and one capital project (with three associated EPAs) were approved by Government without BCUC oversight warrant further discussion in the sections below on the Waneta Expansion EPA and NTL.

a. Waneta Expansion EPA

BC Hydro purchased first one-third and then the remaining two-thirds of the Waneta Dam and Generating Station from Teck in two transactions reviewed and approved by the BCUC.

The Waneta Expansion project is related to the Waneta Dam project only in that it has a similar name and is located immediately downstream from the Waneta Dam: the two projects are totally distinct. In contrast to the purchase of the Waneta Dam and Generating Station, the Waneta Expansion project was directed by the Province, despite resistance from BC Hydro.

BC Hydro confirmed in writing the energy output from the proposed Waneta Expansion would be primarily during the spring freshet period, a time when BC Hydro's system could not incorporate a lot more energy without spilling or selling energy into a low price market. BC Hydro also raised concern that Columbia Power Corporation (CPC) was proposing direct negotiations of the EPA with BC Hydro as the best option, notwithstanding that direct negotiations could be perceived as not following a competitive or transparent process by the IPP community or the public. BC Hydro recommended that CPC apply under the 2010 Clean Power Call.

However, the Minister approved direct negotiation with CPC and Columbia Basin Trust (CBT). Fortis Inc. formed a Limited Partnership with CPC and CBT to construct the Waneta Expansion project, with Fortis holding 51%, CPC 32.5%, and CBT 16.5%.

The Waneta Expansion is a run-of-river project. It has a rated capacity of 335 MW but projected energy of only 630 GWh: therein lies the issue. A 335 MW facility with a 100% capacity factor would generate 3,810 GWh of power. The rated power, 630 GWh, indicates the project has a capacity factor of 21.5%, low relative to other run-of-river facilities. As can be seen in the chart below, the power profile for Waneta Expansion is materially worse than that of a typical run-of-river project. Waneta Expansion generates all of its power at freshet and effectively nothing at any other time of the year. If there was one thing BC Hydro didn't need at the time, and still doesn't need today, it is more freshet energy.

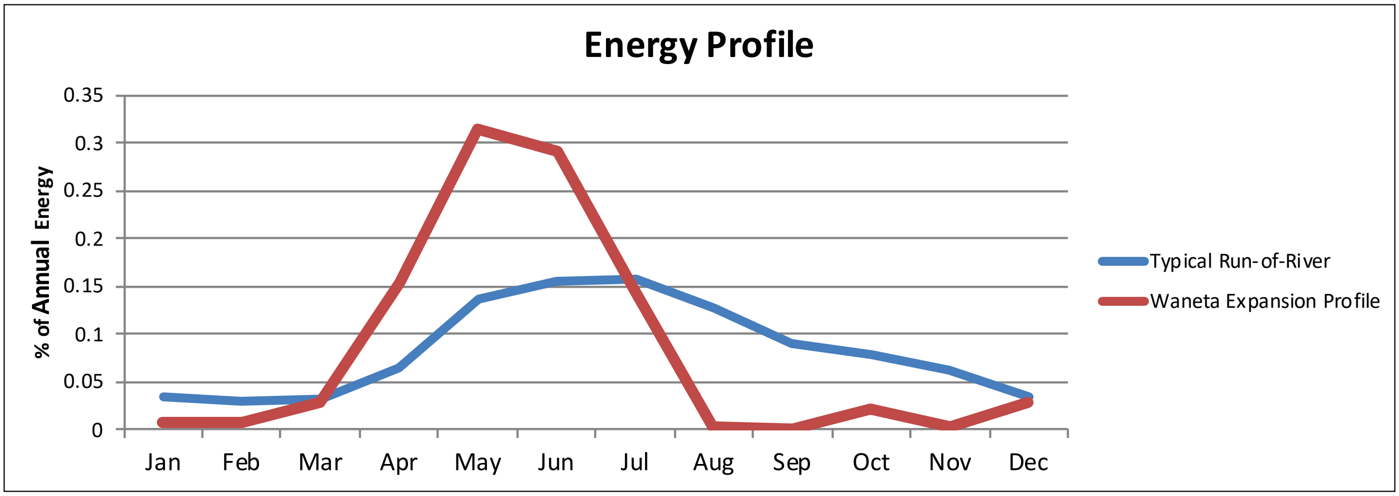


Figure 7: Comparison of Energy Profiles–Waneta Expansion Project vs Typical Run-of-River Hydro

In a typical limited partnership, the partners are isolated from the project risks; the general partner (often a shell corporation) is created specifically for the project and carries all risks. Notwithstanding the financial strength of the limited partners in this case (Fortis, CPC and CBT), the general partner was not able to obtain financing for construction (presumably because the limited partners would not guarantee the obligations of the limited partner). The solution was to direct BC Hydro to adjust the payment schedule in the EPA to enhance the cash flow available for debt service by offering a levelized price for Firm energy, to meet conditions set by the bank.

At the time, the EPA was described as being comparable to other 2010 Clean Power Call deals accepted by BC Hydro. It appears the BCUC reviewed and approved the Fortis side of the transaction, as that deal clearly benefits Fortis ratepayers. The underlying EPA held by CPC and CBT was not reviewed by the BCUC as those entities were exempt for BCUC oversight.

Two sides of the story have emerged regarding the Waneta Expansion project. According to BC Hydro it has the worst profile of all of the run-of-river projects in its portfolio. The Ministry speaks in support of the project, noting the water management benefits it delivers, primarily benefits to winter water.

Ultimately, this review was not able to determine why or to whom the Waneta Expansion project was important or why BC Hydro was directed to accept the EPA.

On Jan. 28, 2019, Fortis announced that it will be selling its 51% interest in the Waneta Expansion project to CPC and CBT for $991 million. Fortis reported that the original cost of the project was $900-million and that COD was achieved in 2015.

The sale demonstrates the profitability embedded in the BC Hydro EPA. Fortis enjoyed 51% of the energy payments for five years and then sold its $459 million (51% of $900 million) original investment for $991 million generating a gain of $532 million in five years. It is certainly unfortunate for the BC Hydro ratepayers that this EPA was not subject to BCUC review.

b. Northwest Transmission Line

Northwest Transmission Line (NTL) is a 287 kV transmission line that came into service in 2014. It follows roughly the Stewart-Cassiar Highway (Highway 37) for 335 kilometres from near Terrace to Bob Quinn Lake.

NTL is a greenfield project that was designed to extend BC Hydro's transmission grid further north into an area rich in mining potential and to provide clean power to the community of Iskut. It also served as an interconnection point for IPP projects.

The project was announced with a cost of $404 million. The transmission line was extended, increasing projected cost to about $600 million. On completion in July 2014, the cost had increased to $704 million. The key drivers of the increased costs were project complexity, challenging conditions and actions taken to ensure the project was in-service on time.

We understand the Federal Government was first to announce its support for NTL, committing to a contribution of $130 million from its Green Infrastructure Fund, subject to the NTL offering a grid connection to the community of Iskut.

When the NTL was announced by the province, Galore Creek (NovaGold/Teck) was identified as the first project that would be serve by the NTL. The province confirmed that Galore had committed to contribute $158 million to the project, with the province to fund the $246 million balance (projected at the time).

Days later, NovaGold and Teck announced that the Galore Creek mine was to be put on hold, leaving the NTL without a local energy source or a load customer. Ultimately the province would add three AltaGas Run-of-River hydro projects (Forest Kerr, Volcano, and McLymont Creek) as the anchor tenants on the NTL.

When the NTL was announced, the Province stated that "the province will invest." Very soon that became, "the Province will tell BC Hydro to invest." When the Province committed to NTL, it was purely an economic development project; there was no business case that would support BC Hydro making an independent decision to invest, especially given that most of the transmission line's capacity is still not being used. The Government had BC Hydro take a risk that did not pay off. (the discussion of the NTL continues in Section 28).

24) Modernizing BCUC

With the announcement of the *Clean Energy Act* on April 28, 2010, Government issued a backgrounder on "Modernizing the British Columbia Utilities Commission." In the context, "modernization" is an interesting euphemism.

The BCUC's role is defined in legislation. It is to ensure customers receive safe, reliable energy at fair rates while ensuring the service providers can earn a fair return on their investments. These rates fund ongoing operations and infrastructure for the energy utilities.

In this announcement of the *Clean Energy Act*, "modernize" meant eliminating the independent oversight of the BCUC's for approval of certain material projects BC Hydro was directed by Government to undertake, including:

- Northwest Transmission Line
- Mica units 5 and 6
- Revelstoke unit 6
- Site C

- Bioenergy Phase 2 Call for Power
- BC Hydro's Integrated Power Offer
- Clean Power Call
- Standing Offer Program
- Feed-in Tariff
- BC Hydro's Smart Metering and Smart Grid program

The *Clean Energy Act* moved oversight of BC Hydro's long-term planning from the BCUC to Government, with the requirement that BC Hydro submit an IRP to Government, not to the BCUC as had been common practice previously with the IEP and the LTAP for example. The initial plan would consider B.C.'s electricity needs over the next 30 years and would set out how BC Hydro intended to implement the energy objectives that were set out in the *Clean Energy Act*. Once Government approved that plan, the BCUC would be required to be guided by the plan in its future decisions.

Such a move would certainly achieve the goal of the "modernization" set out in the announcement, which was "to ensure that there is alignment between the Government's policy priorities, how BC Hydro delivers on those priorities, and how the BCUC provides regulatory oversight." Removing BCUC from the approval process on key expenditures and projects was clearly intended to ensure "alignment."

In this "modernized" role, the BCUC would continue to regulate BC Hydro rates, safety and reliability, and operating costs. But in regulating BC Hydro's rates, the BCUC would need to accept large costs for IPPs and capital projects that the BCUC now had no ability to approve or reject.

The table starting on page 48 lists IPP EPAs showing whether or not the projects were subject to BCUC scrutiny and approval.

25) 2010 Clean Power Call

BC Hydro issued the Clean Power Call RFP on June 11, 2008, structuring it to accommodate larger projects requiring additional development time. (There is a date confusion in the naming of the various BC Hydro calls; they are typically named to reference the period EPAs were signed, rather than the date the call was issued.)

BC Hydro staff were clearly aware of Government's vision for self-sufficiency and understood that undersupply would not be acceptable. In November 2008, BC Hydro received 68 proposals and ultimately awarded 25 EPAs for 27 projects (three projects were combined into a single EPA) by August 2010, representing 3,266 GWh per year of Firm energy and 1,168 MW of capacity. The 27 projects included 19 run-of-river projects, six wind projects, one storage hydro project and one waste heat project.

BC Hydro judged the cost effectiveness of the proposals and the call itself based on comparisons to other BC Hydro processes and similar processes undertaken by other jurisdictions, and the projections outlined in the 2008 LTAP.

BC Hydro considered the Clean Power Call to be aligned 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% of total generation. The Call was also seen as supporting other 2007 Energy Plan Policy Actions:

- **Policy Action No.10**–ensure self-sufficiency to meet electricity needs by 2016.

- **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.
- **Policy Action No. 22**–replace the Firm energy supply from Burrard Thermal Generating Station (Burrard) with other resources. On October 28, 2009, the Government 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

In addition to the Firm energy acquired under the 2010 Clean Power Call, BC Hydro would be purchasing approximately 800 GWh/year of non-Firm energy which represents about 20% of the total energy deliveries. The need for energy from the 2010 Clean Power Call EPAs appears to be based on capacity and energy estimates applying factors including:

- Burrard Thermal having a 900 MW capacity but 0 GWh of Firm energy as a result of the direction to the BCUC;
- 865 GWh/year of Firm energy from BC Hydro's purchase of one-third interest in the Waneta Dam and Generating Station, assuming that the transaction would be approved by the BCUC (which occurred in February 2010);
- None of the 3,000 GWh/year insurance called for in the 2007 Energy Plan or in Section 3 of Special Direction #10 to the *Utilities Commission Act* (now repealed) is included. If the insurance requirement is added to the load/resource energy gap would increase by that amount.

The financial risk assessment undertaken during the evaluation considered the financial strength of proponents and their partners in relation to the capital required to develop the projects, notably whether there was a risk of the project not being developed due to a lack of debt or equity financing. It does not appear this assessment strategy considered the risk to BC Hydro and to the ratepayers from EPAs committing to a purchase price well in excess of the value of the energy at market.

Three observations should be made at this point in the chronology.

In Section 24, we discussed how the market at Mid-C responded to the economic downturn and the appearance of large volumes of inexpensive natural gas; energy rates were forced down. The discussion of Anomaly Co. in Section 36 demonstrates that prior to this market change, Run-of-River projects could be successfully developed at the Mid-C rate. Post 2009 the reduced rates at Mid-C would likely not support new construction of generating facilities.

The form of energy that was now dominating the Mid-C rate was natural gas fired and by definition not clean energy. Post 2009, a rate above Mid-C would need to be offered to attract new clean energy construction. That being said, in Section 35 there is a discussion of how BC Hydro signalled its tolerance to higher rates as a tool to generate the construction volumes demanded by the Government. Section 39 estimates the profits and capital gains made by the project developers as a result to the rate premiums offered by BC Hydro. There is today, no way of knowing the real premium above Mid-C that BC Hydro should have offered the market post 2009 to generate new energy projects. What is clear is that the rates offered to buy the construction volumes demanded by Government were far in excess of the premium above Mid-C that would have been sufficient to generate financially viable clean energy projects.

Section 44 discusses a strategy for the renewal of the EPAs upon their maturity and notes that the excessive rates currently being paid by BC Hydro during the first term of the EPAs have been sufficient to retire the construction cost base of the projects.

The current Mid-C rates are low due to inexpensive natural gas fired energy. Notwithstanding, the current Mid-C rate is likely sufficient to support IPPs going forward; there is likely no commercial reason for BC Hydro to pay a premium above Mid-C upon the renewal of the EPAs, especially when it does not require the energy.

The 2010 Clean Power Call met BC Hydro's pricing expectation. In August 2010, BC Hydro announced EPA awards with a weighted average adjusted Firm energy price of $124/MWh ($2009).

BC Hydro estimated the cost of new long-term Firm energy supply in the 2008 LTAP proceeding as $124/MWh in 2008 constant dollars. 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.

The chart of historic Mid-C prices indicates the market would have valued this power at about $38 /MWh.

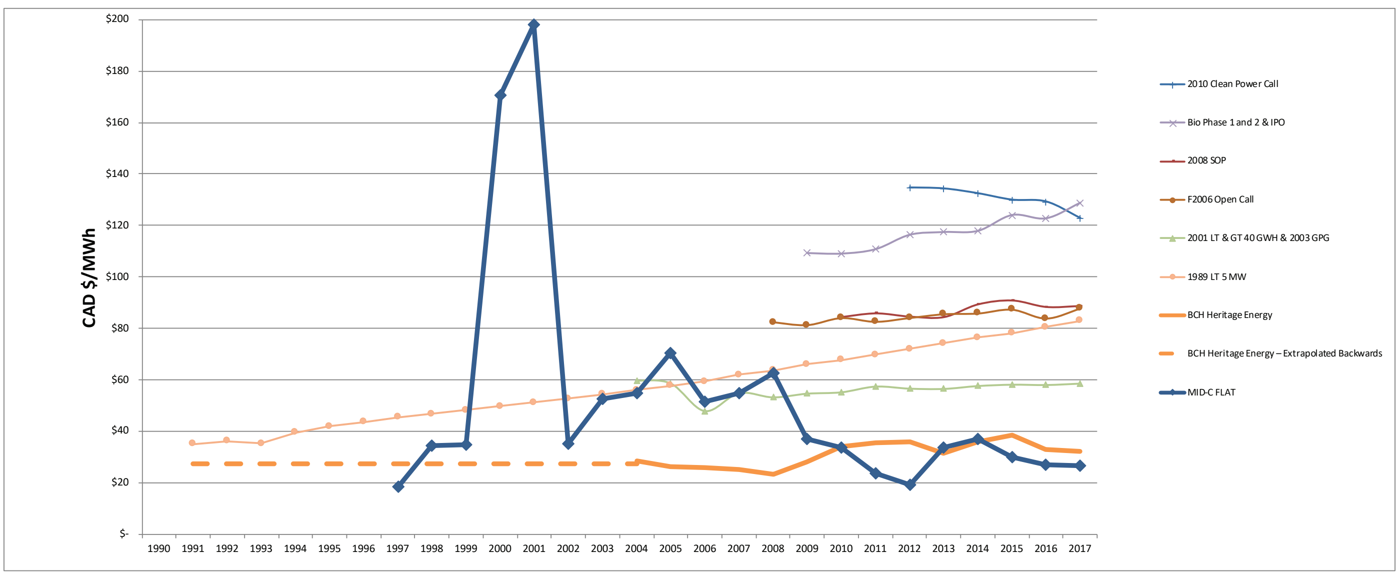


Figure 8: BC Hydro IPP Portfolio History Graph #6–2010 Clean Power Call

In interviews it was reported that the Board was concerned with the volumes of IPP projects not reaching COD. In the 2006 Open Call for Tenders, 56% of approved projects failed to reach COD.

Reacting to the Premier's November 2009 speech wherein he validated IPP concerns with protracted negotiations, the Board sought to reduce the rate of EPA termination: a lower rate of termination would serve as a proxy indicator that BC Hydro was cooperating with the Government's vision. At one point, a protracted Board meeting received updates on the progress each individual project was making towards COD and the supportive actions of BC Hydro staff for each project. The EPA termination rate fell to 20% with the 2010 Clean Power Call.

Looking back, the high EPA termination rates were likely due to permitting delays, a lack of due diligence on the part of the proponents that was compounded with the economic downturn, and potentially the option to move the project into a subsequent call that was offering better rates and terms.

Government's demand for IPP project volumes created a "feeding frenzy" when BC Hydro issued calls, with parties taking water licenses on potentially viable rivers to ensure they had a seat at the table. Faced with the engineering reality of a project, once due diligence was completed, a number of proponents withdrew, generally prior to the start of construction.

The IPP industry association publicly complained that BC Hydro staff and staff in the environmental regulation process were being "difficult." In interviews, BC Hydro staff indicated they believed industry's concerns arose because BC Hydro refused to improve the terms of the EPA after it was signed. BC Hydro staff also note that the increasing trend in EPA rates from one call to the next call did result in some proponents that chose to withdraw from the fully executed EPAs so they could seek the same opportunity at a higher price under a future call.

26) Northwest Transmission Line and direct negotiations

Having committed BC Hydro to the construction of the NTL, the Province took steps to energize the line with new capacity from the Northwest, and set about finding local load customers for that capacity.

The 2010 Clean Power Call was underway at this time. Three projects were among the group of IPPs qualified under that Call; Forrest Kerr Hydroelectric, McLymont Creek and Volcano Creek. These projects were all owned by AltaGas and located near the terminus of the NTL.

Forest Kerr first appeared as a signed EPA under the 2003 GPG call. The investor terminated that EPA and the same project reappeared as meeting the eligibility requirements for the 2010 Clean Power Call. EPAs awarded under the 2003 GPG were generally for 15-20 year terms, with a levelized adjusted ceiling price of $55/MWh. The call allowed for 50% of the price to escalate with CPI.

As this group of projects had the potential to be the anchor tenant on the NTL with locally generated power, they were pulled out of the Clean Power Call and brought into direct negotiation process. Negotiations were led by the province (represented by a senior representative of EMPR), with BC Hydro, BCTC and AltaGas all at the table.

With respect to NTL, the Federal Government offered a contribution of $130 million, AltaGas offered a contribution of $180 million (based on the cost avoided on a connection to the existing grid), and the Province (BC Hydro) was to fund the balance.

The deal package, including the three EPAs, proved difficult to negotiate. EMPR continued to lead the negotiations. There were quadrilateral meetings interspersed with bilateral meetings between EMPR and AltaGas and EMPR and the Tahltan First Nation. The Tahltan First Nation did not participate in the negotiation of the EPA, but rather in respect of connecting the community of Iskut to replace the use of diesel generated power (presumably to meet the condition of the Federal Green Infrastructure Fund).

Ultimately, the EPA negotiations moved to an open-book review, where AltaGas allowed the parties to inspect their projections for the IPP. This open-book review was an attempt by EMPR to ensure excess profits could not be negotiated by AltaGas. Ultimately the deal between AltaGas and EMPR produced an energy price that reflected the recovery of costs and a target percentage return, net after tax.

Due to commercial confidentiality, BC Hydro does not make public the specific terms of individual EPAs. Accordingly, this review could not comment on the exact financial details of these three EPAs. That said, there is no reason to expect that the Province and AltaGas went through the trouble of an open-book review to negotiate a price less than that automatically available to all other EPAs awarded under the 2010 Clean Power Call, which had a 20-40-year term, a maximum permitted 50% CPI escalation, and a weighted average bid price for Firm energy of $140/MWh.[3]

AltaGas reported on May 28, 2010 that it held a 60-year Consumer Price Index-tied EPA on the 195 MW Forrest Kerr IPP and that the project has a capital cost in the range of $700 million. On November 2, 2015, AltaGas announced that its 66 MW McLymont Creek IPP had reached COD, marking "the final stage of our $1 Billion Northwest Projects…other facilities include …16 MW Volcano Creek.

> [BC Hydro's treatment of inflation in NTL EPAs is discussed in detail in Section 34. Of note here is that while it was negotiating with Alta Gas, the Ministry was facing an urgent need for tenants on the NTL. In the face of that need, the Ministry agreed to adjust the EPA rates at full CPI for the 60-year term of these three EPAs. The typical EPA under the 2010 Clean Power Call had a term of 30 years and was offered 50% CPI escalation.]

Even if AltaGas negotiated only the weighted average bid price for Firm energy of $140/MWh, (or the $101 /MWh ($2009) EPA levelized plant gate total energy price used to evaluate the call), awarded under the 2010 Clean Power Call and an inflation protected 60-year term, such an agreement would still represent a material improvement from the EPA Forrest Kerr held previously under the 2003 GPG Call that typically offered a 15-20-year term and a levelized adjusted price less than $55 /MWh in 2003.

On June 13, 2018, AltaGas reported that it had sold a 35% interest in these projects for $922 million, implying a value of $2.6 billion for the group of three projects. An analysis completed by CIBC indicates the sale price was 27 X 2017 EBITDA, which materially exceeded the predictions CIBC had offered its clients.

AltaGas has given an indication of original construction cost in the range of $1 billion on these projects. The confirmed market value points to a capital gain of perhaps $1.6 billion–a generous quid pro quo for the $180 million contribution negotiated by the Province to justify the commercial viability of the NTL project.

The first load customer for the NTL was the Red Chris Mine. Red Chris is owned by Imperial Metals. Imperial built the 93 km Iskut extension to the NTL and sold that transmission line to BC Hydro for $52 million. That extended the NTL from Bob Quinn Substation to a new substation at Tatogga Lake. BC Hydro's purchase of the Iskut extension was exempted from BCUC review.

Red Chris/Imperial was then charged for the connection from the NTL to the Red Chris mine, in accordance with a BCUC approved tariff. The amount of the connection charge is commercially confidential information.

3 BC Hydro reports Levelized prices to ensure comparability. The 2010 Clean Power Call was reported as delivering a levelized price of approximately $101/MWh for total energy ($2009) and $124/MWh for Firm energy

27) EVOLUTION OF THE STANDING OFFER PROGRAM 2010

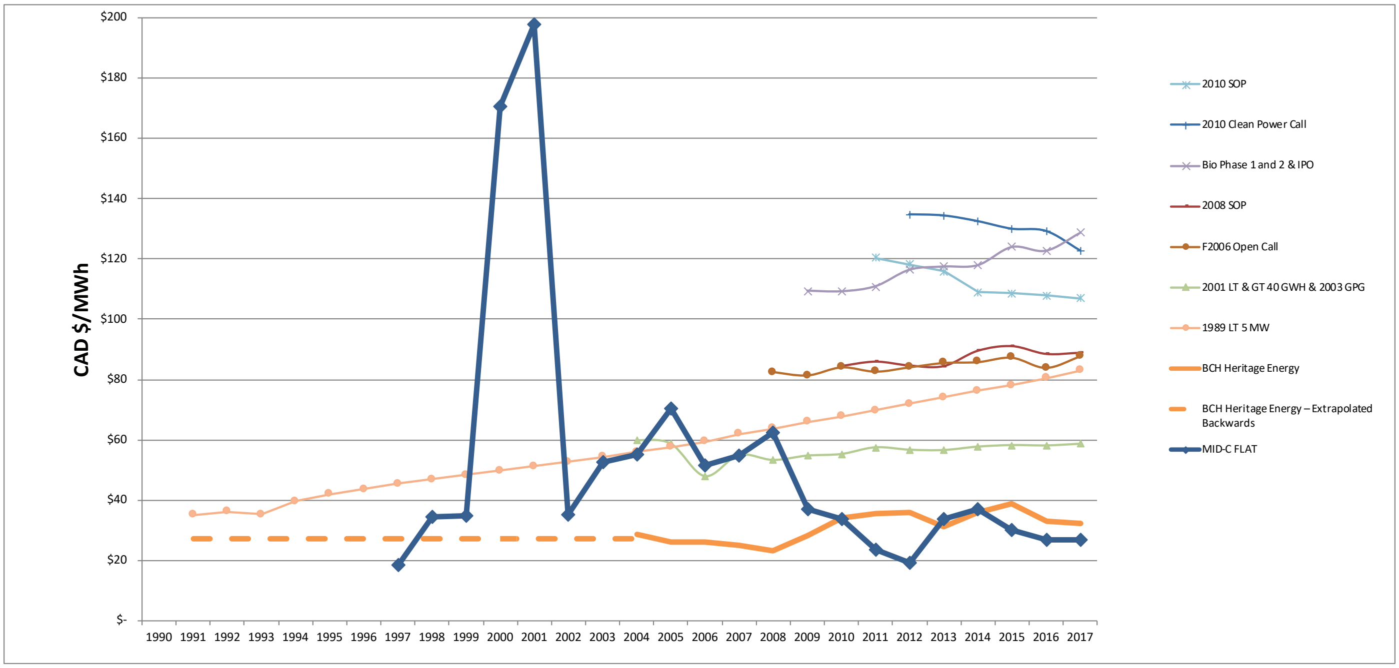


Figure 9: BC Hydro IPP Portfolio History Graph #7–2010 SOP

The 2010 **SOP** is an exceptional category of energy acquisitions as it is a legislated requirement pursuant to the *Clean Energy Act*. The Act sets out in subsection 15(2) that BC Hydro must establish and maintain a standing offer program to acquire electricity from eligible facilities. Eligible facilities are generation facilities with a maximum nameplate capacity (or some other capacity prescribed for the purposes of this section). Subsection 15(3) provides that BC Hydro may establish the terms and conditions of the offers under the SOP.

In 2013, BC Hydro's IRP recommended that the annual target for the SOP be raised from 50 GWh/year to 150 GWh/year. The initial draft of the IRP that BC Hydro delivered to Government in August 2013 did not include an increase in the annual target, and this recommended action was added in the final draft approved by Government in November 2013. Within the final draft, BC Hydro explained a set of recommended actions, including the increase in SOP target volume, as ensuring that "the IRP aligns with and supports the Province's long-term vision for clean energy in B.C." Given the conflict between the recommended increase in the SOP annual target and BC Hydro's focus on reducing cost commitments for EPAs elsewhere within the IRP, it was clear to BC Hydro staff that changes to the SOP were driven by Government.

Chapter 9 of that same November 2013 IRP speaks to portfolio optimization, which is in direct conflict with expanded SOP limits:

> **9.2.4 Recommended Action 4: Optimize existing portfolio of IPP resources**
>
> **Optimize the current portfolio of IPP resources according to the key principle of reducing near-term costs while maintaining cost-effective options for long-term need.**
>
> The combined Independent Power Producer (IPP) supply and targeted DSM results in BC Hydro having an adequate energy supply until F2028 and adequate capacity supply until F2019, as shown in section 4.2.6. BC Hydro is

> undertaking time-critical actions over the next few months to prudently manage the costs of the energy resources that it has acquired, committed to or planned to target over the next five years. These actions include negotiating agreements to defer commercial operation date (COD), downsize or terminate pre-COD EPAs. Based on the EPA actions, BC Hydro expects to achieve an energy supply reduction of contracted energy by F2021 of roughly 1,800 GWh/year, translating into a reduction in attrition-adjusted forecasted Firm energy supply of about 160 GWh/year by F2021.

While Government was raising project size limits and SOP aggregate quotas dramatically to permit more projects and much larger projects into the SOP, BC Hydro was at the same time trying to defer IPPs coming on line and terminating, where possible, those that hadn't reached COD. Management at BC Hydro understood the looming problem but was still obligated to meet the direction mandated by Government. While it was trying to respond to Government direction for more IPPs, BC Hydro was trying to moderate the impact the IPPs were having and were predicted to have.

On June 12, 2015 in the Mandate Letter from the Premier to the Minister of Energy and Mines, the Premier directed the Minister to continue working with BC Hydro and Clean Energy BC to identify further opportunities for private clean energy producers in British Columbia. In October 2015, the Minister of Energy and Mines admitted that the relationship between BC Hydro and IPPs had been strained in recent years. BC Hydro staff advise that in their opinion, this "strain" resulted from BC Hydro applying the terms of the RFPs and EPAs in what they saw as a consistent manner and in the interests of the ratepayers, while industry believed BC Hydro should have shown "flexibility."

The solution directed by Government to fix this strained relationship was for BC Hydro, Clean Energy BC and the Ministry to enter into a Memorandum of Understanding (appearing as Appendix D), whereby the parties committed to coordinating communications to promote an understanding of the benefits of the sector's current operations and future growth, including the value to the ratepayer and cost competitiveness.

The Memorandum of Understanding provides an agreement among the parties to engage transparency on BC Hydro's policy for electricity purchase agreement renewals and into load, demand side measures and supply forecasts developed by BC Hydro, including the various factors that impact those forecasts. The Memorandum of Understanding also agreed to participation in a continuous process of evaluation and improvement of BC Hydro's procurement processes for acquiring independent power resources.

Clean Energy BC is reported in the media saying "This agreement opens up clear channels of communication so that we can continue to deliver clean power to British Columbians, while providing more certainty for investors and our member clean power companies." The MOU expired in December 2017 and was not renewed.

Of note, the SOP continues to exist today, but in March 2018 BC Hydro announced that it would not issue new EPAs under the program, pending the completion of the Comprehensive Review of the corporation. BC Hydro has no ability to terminate the SOP. Under Section 15(2) of the *Clean Energy Act*, BC Hydro must establish and maintain the SOP in accordance with its rules unless Government establishes prescribed circumstances under which the SOP does not need to be maintained and established pursuant to regulation. Alternatively, Government can terminate, or enable BC Hydro to terminate, by repealing subsection 15 (2) of the *Clean Energy Act*.

28) Too Much Energy

In July 2016, BC Hydro filed a rate application with the BCUC that indicated the decline in the rate of industrial customer load growth posed a new and significant impediment to achieving the 2013 10 Year Rates Plan. The reduction of industrial load wasn't new. It actually started in 2009 but was only acknowledged in this 2013 submission. Section 24 discussed the market changes in the 2008/9 period, including the loss of significant industrial load.

What was "new and significant" was the recognition that the financial impacts of Government's directions could no longer be contained within BC Hydro. BC Hydro was forced to publicly acknowledge these financial issues.

By 2016, the impact of Government's direction of the energy planning processes at BC Hydro couldn't be ignored. During Estimate Debates in the Legislature, it was reported that in 2015, BC Hydro paid approximately $17.5 million to select biomass IPPs, to avoid buying approximately $26 million in power that was not needed, thereby saving BC Hydro a net of $8.6 million. This likely represents BC Hydro's commercial response to an oversupply situation and a situation of imbalance between Firm and Intermittent power.

Consider the simplistic trading example in Section 7 and the discussion of dispatchability in Section 8. Run-of-River can't be stored and is based on take or pay contracts, so BC Hydro must use (or at least pay) for all the run-of-river power, as it is delivered. In freshet, BC Hydro uses its reservoirs to make room in the system for the run-of-river power. If more run-of-river energy is generated than can be stored, BC Hydro must either spill water, trade or find some other dispatchable source of Firm power it can "turn down" to make room. Next in line for "dispatchability" are the biomass IPPs. BC Hydro can turn them down and pay standby charges (as opposed to buying the power), which appears to be what happened in this scenario.

This scenario demonstrates that BC Hydro has a disproportionate level of Intermittent power from run-of-river and wind compared to dispatchable Firm power from Heritage Assets and Biomass IPPs that can balance and firm the supply to the grid.

Excess power at freshet is worth very little on the market. Typically, it could be worth $5-10 /MWh at peak time of day and likely zero in the low demand periods in the middle of the night. The example cited in the Legislature illustrates the extent of the power imbalance at freshet. At freshet, BC Hydro was forced to turn off the water in its dams and then turn off the dispatchable biomass IPPs at a cost of $17.5 million, all so that it could accept the IPP run-of-river power it committed to buy at ~$120 /MWh, at a time that power is worth perhaps $5 /MWh.

Obviously, this is not an optimal situation. It is also a situation due solely to Government requiring BC Hydro to deliver on its policy directives.

Government influenced the energy planning process to create the appearance of an energy shortfall. Government then directed BC Hydro to accelerate engagement with IPPs. The only option BC Hydro had to accelerate IPP contracts was to commit to long-term EPAs at rates that were clearly in excess of the market value of the power at that time.

This imbalance represents a material inefficiency that will persist until demand increases. The cost of this imbalance, while material, is difficult to estimate.

BC Hydro must now manage run-of-river IPPs on take or pay contracts, Firm dispatchable biomass IPPs and Firm dispatchable Heritage Asset storage dams. There is a logical sequence. When there is surplus power (like at freshet), BC Hydro should accept the run-of-river power, because it is under take or pay contracts, and displace the dispatchable power. In this situation, BC Hydro should turn down generation at the storage dams, because the energy represented by the stored water can be sold into a more favourable market later. If BC Hydro still has excess power, it should turn down the dispatchable biomass IPPs, as the price of biomass IPP energy is in the same range as run-of river IPP energy and turning down the biomass projects saves the price of fuel.

This review agrees with the comments made by the Minister in the Legislature: turning down biomass projects in times of surplus, so that BC Hydro pays only the capital component of the rate instead of the full price of power, is the commercially correct decision.

29) Energy Procurement Processes

BC Hydro procures energy in a manner that is compliant with provincial policy direction in all material respects. BC Hydro commissioned independent reviews of its procurement practices by Merrimack Energy Group, Inc. and of the template EPA for the 2010 Clean Power Call by Navigant Consulting, Inc. The issues identified by these two reports would generally be considered to be minor. It isn't the procurement processes that have got BC Hydro into trouble. BC Hydro was told to buy too much energy and to meet its shareholder's direction, paid too much for that energy.

30) Direction to Change Energy Planning

Interviews conducted for this review support the conclusion that the 2007 Energy Plan and Special Direction #10 (provided as Appendix E) amounted to direct Government interference with the energy planning process at BC Hydro, with the intent to create the appearance of an energy shortfall. The resulting energy shortfall was then used to justify an expansion of the IPP portfolio and gave rise to the calls for power issued since 2007, including the 2010 SOP, which was directed by legislation.

Special Direction #10 gave effect to the 2007 Energy Plan, directing:

- energy self-sufficiency, which eliminated the ability to plan for market purchases to meet load. Previously, BC Hydro had relied on trading for 2,500 GWh in its energy plan.
- 3,000 GWh of "insurance" capacity above the level of self-sufficiency
- effectively directed BCUC to approve all Biomass projects presented.

Creating a 5,500 GWh projected energy deficit

In Recommendation 19 of the 2007 Energy Plan Government directed that the province would achieve zero net greenhouse gas emissions from existing thermal generation plants by 2016. This was effectively a direction that BC Hydro must close Burrard Thermal by 2016.

In the development of the 2007 Energy Plan there were discussions with BC Hydro pertaining to the closure of Burrard Thermal. BC Hydro proposed that it meet the Government's direction to close Burrard Thermal by systematically phasing it out. BC Hydro proposed an initial reduction of 50% to planned generation, with full closure to occur by 2014. In Recommendation 22 of the 2007 Energy Plan Government supported BC Hydro's plan.

BC Hydro operated on the basis the directed closure of Burrard Thermal could be achieved through its recommended phase out plan. It operated on the basis the planning assumption for energy coming from Burrard Thermal should be reduced from 6,000 GWh to 3,000 GWh.

Increasing the projected energy deficit from 5,500 GWh to 8,500 GWh

In the normal course, BC Hydro presented the understanding respecting the staged phase out of Burrard Thermal to BCUC for formal approval as part of its 2008 LTAP submission.

In response to Governments direction BC Hydro moved immediately to acquire 8,500 GWh of incremental Firm energy. BC Hydro issued:

- February 2008–Bioenergy Phase I Call
- April 2008–Standing Offer Program
- June 2008–2010 Clean Power Call
- September 2009–Integrated Power Offer
- May 2010–Bioenergy Phase 2 Call

As described in Section 23, the BCUC rejected the 2008 LTAP submission and with it, the 3,000 GWh reduction in capacity associated with the phase out of Burrard Thermal.

Reducing the projected energy deficit from 8,500 GWh back to 5,500 GWh

Government reacted to BCUC's decision by bringing in the 2010 *Clean Energy Act*, which resulted in the "modernization of BCUC" (Section 25) and Policy Action No. 22 directing BC Hydro to replace the Firm energy supply from Burrard Thermal Generating Station with other resources. On October 28, 2009, the Government 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."

Increasing the projected energy deficit from 5,500 GWh to 11,500 GWh

In 2013, Government eliminated the requirement for 3,000 GWh of "insurance" energy.

Reducing the projected energy deficit from 11,500 GWh to 8,500 GWh

Also in 2013, Government changed the basis of energy planning for storage dams from a "critical water" assumption to an "average water" assumption. The impact of this change is that for planning purposes the storage dams are assumed to be fuller and hence to have more water for energy generation. The impact of this change to assumptions was to create the appearance of more water and 4,100 GWh in new generation capacity.

Reducing the projected energy deficit from 8,500 GWh to 4,400 GWh

After 2007, BC Hydro operated with the intent that it needed to buy 8,500 GWh of incremental Firm Energy. While it certainly increased its target buy to 11,500 GWh in response to the elimination of Burrard Thermal that change likely had little impact. BC Hydro was already buying as much Intermittent IPP energy as it could and as fast as it could. BC Hydro likely had no capacity to accelerate its procurements and its response to Government direction further.

Government changed the parameters that drive energy planning at BC Hydro. The new parameters drove the prediction that BC Hydro would need 8,500 GWh/year of new, Firm energy to meet projected load (and finally to 11,500 GWh/year, though that last change had little actual impact). BC Hydro's mandate requires it meet demand with Firm power, so the appearance of an energy shortfall required BC Hydro to react by obtaining incremental Firm energy.

The self-sufficiency direction from Government eliminated both the option for BC Hydro to build the new capacity itself and the option to buy the energy on the open market. The only option Government left available to BC Hydro was for it to procure energy from additional IPP projects. Run-of-River, Wind and Solar IPPs produce non-Firm energy in addition to the Firm energy BC Hydro needed to buy; the EPAs create a take or pay obligation under which BC Hydro was forced to buy the non-Firm energy in addition to the Firm energy it needed.

From 2007 forward, BC Hydro worked to achieve Government's directions. By the time the IRP was submitted in November 2013, BC Hydro was concerned with the overbuying and the rates being paid; staff was directed to terminate IPPs that were not following the terms of their EPAs. At the same time, other staff was still trying to sign new EPAs under the SOP to deliver on Government's directions.

BC Hydro clearly acted with the intent to meet government's policies and directions by working to procure the incremental 8,500 GWh of Firm energy (or the updated target of 11,500 GWh of Firm Energy). We will likely never know exactly where in relation to that target BC Hydro landed. Given Government's direction and BC Hydro's intent to comply, the estimate of the impact of the policy direction could be based on 8,500 GWh of incremental Firm energy.

Government expects its Crown Corporation to comply with its policy directions, hence for BC Hydro to purchase 8,500 GWh in incremental Firm energy Government knew BC Hydro did not need. Government knew its directions would create a cost to BC Hydro ratepayers. This report is not aware of Government inquiry as to the probable impact of its actions.

31) Government Could Have Told BC Hydro to Stop

The change in the energy market was apparent in January 2009 and the reducing levels of industrial load (6.4% of total system load) were apparent soon after.

Even recognizing there is a lag between signing an EPA and delivery of energy, the following graph of annual energy from IPPs is stark.

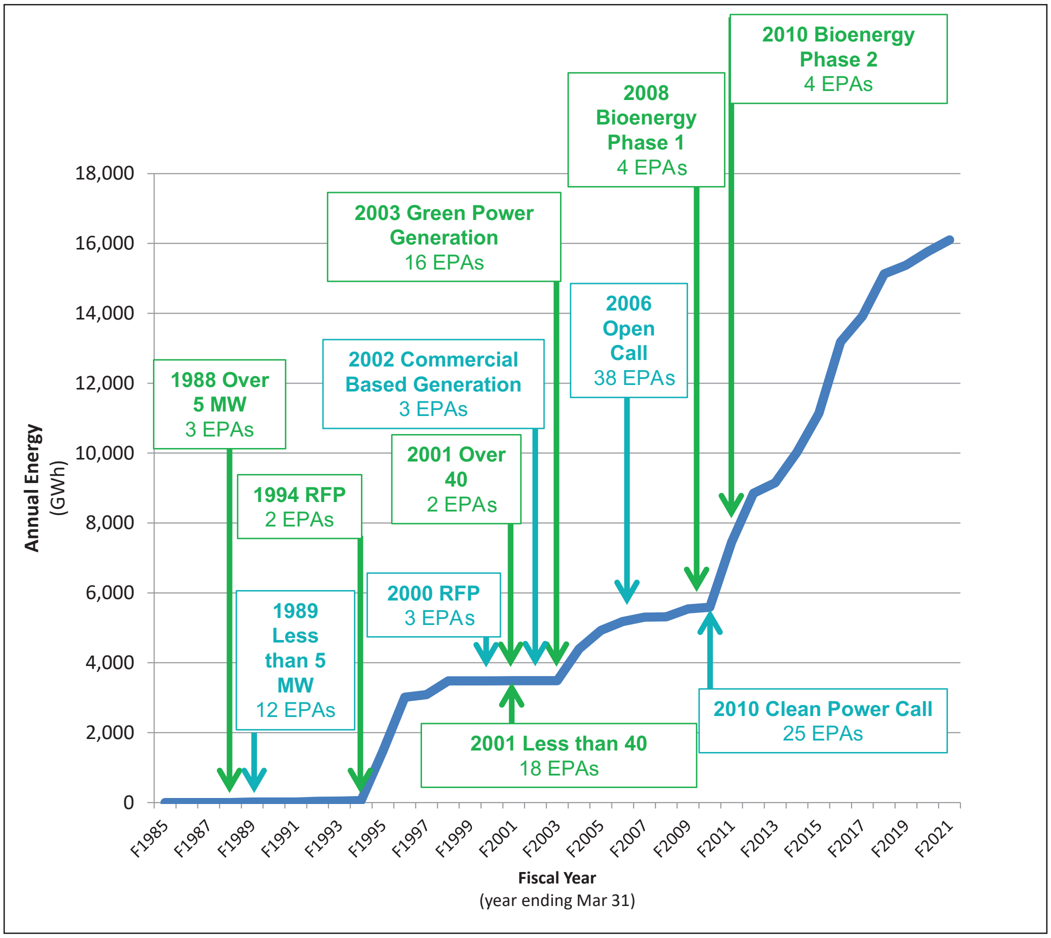


Figure 10: History of BC Hydro Procurement Processes and Related Contractual Energy (GWh/y)

Note:

- The number of EPAs represents the number of EPAs awarded in each call (as opposed to the number of EPAs that remain active from each call).
- Volume represents the estimated contractual volume in BC Hydro's portfolio over time.
- Forecast volumes are from the November 2018 IPP Forecast.

In interviews, both the Ministry and BC Hydro cite examples where staff tried to alert the Government to the changes in the market. An IPP project can typically take about four years to permit, construct and bring to commercial operation, so there is a long lead time between when the EPA is signed and when the project meets its COD. Government failed to respond to the changing market until 2012-13, by which point BC Hydro was committed to energy that wouldn't come online until 2016, meaning the impact of the directions and the changes to planning parameters would continue to grow at least to that point.

The estimate of impact is a moving target. While BC Hydro took actions with the intent of delivering the 8,500 GWh of new Firm energy demanded by Government's policy directives, BC Hydro has not assessed where in relation to that target it ended up. However, it is clear that BC Hydro is currently in an energy surplus which will continue into the 2030s.

The conclusion drawn is that Government gave directions to BC Hydro that Government intended to:

- direct the energy planning process to the end that BC Hydro would be forced to acquire Firm energy it did not need, and
- manage policy to eliminate BC Hydro's option to build capacity or to rely on market trading to acquire Firm energy, thereby leaving BC Hydro with only the option of buying new energy from IPPs.

Run-of-River, Wind and Solar IPPs generate Intermittent energy. It is unlikely that BC Hydro managed to buy 8,500 GWh of new Firm IPP energy (which would equate to approximately 10,000 GWh of blended IPP energy. The five calls for new energy issued by BC Hydro as its response to Government's directive to buy have ultimately resulted in EPAs delivering a contracted 9,500 GWh of incremental IPP energy. This is likely the amount of energy BC Hydro managed to acquire in response to Government's directions. BC Hydro would intend to Firm that Intermittent energy using its existing Dispatchable assets. As seen in Section 29, the level of non-Firm IPP energy now under EPA has overpowered BC Hydro's Dispatchable assets. BC Hydro has too much power and a lot of it is of the wrong type (Intermittent).

This report found no information to indicate Government considered the financial impact its policy directives would have on BC Hydro. This report found the BC Hydro acted with clear intent to meet the directives set for it by its shareholder.

The impact of the policy directives given by Government should be considered from two perspectives. First, an estimate of the impact expected from the Government directives at the time they were issued. Second, the actual impact BC Hydro is experiencing, based on the EPAs that likely resulted from BC Hydro's response to government's directions.

To estimate the financial impact Government should have expected its policy directives to create, this report assumes that the policy directive caused BC Hydro to acquire exactly the 8,500 GWh of incremental Firm energy.

Estimate of the impact of the policy directive from Government that BC Hydro must acquire 8,500 GWh per year of incremental Firm energy:

Average cost of 8,500 GWh of Firm energy acquired in 2009 is assumed to be $125/MWh[4]

Estimated market value of this surplus energy, if sold at Mid-C is assumed to be $25 /MWh[5]
(ignoring time of delivery, the cost of BC Hydro firming the Intermittent energy, line losses, transmission costs, etc.)

The incremental cost of the energy overbuy would then be

($125-$25) / MWh x 8500 GWh/year = **$850 million per year**

The average EPA in the period is assumed to carry a 30-year term.

Total impact of the policy directive can be estimated as:

($850 million * 30 years[6]) = **$25.5 billion over 30 years.**

4 The rate used in the impact calculation is the average rate for Firm energy for the 2010 Clean Power Call, which was initiated as part of BC Hydro's response to Government's directives. The weighted average bid price for Firm energy under the 2010 Clean Power Call was $139.9 /MWh. In this impact calculation, C$125 /MWh is used to be conservative.

5 Most of the surplus Run-of-River energy is produced at Freshet when the Mid-C rate is much lower than the annual average Mid-C reflected in the impact calculation. Again, the rate used in the impact calculation, C$25 /MWh, is believed to be conservative.

6 Assume each underlying EPA had the typical 30-year term and each has 20 years left to run.

Notwithstanding the energy was not needed when Government told BC Hydro to buy, at some point load growth will catch up and the energy will no longer be surplus. BC Hydro expects to be in energy surplus into the 2030s, so this report expects the annual impact of the over-buy will be felt for some 20 years and the impact of the policy directives would be estimated as:

($850 million * 20 years) = **$17 billion over 20 years.**

In interviews, both the Ministry and BC Hydro advise that Government was made aware of the risks inherent in its directives (Section 23). Government was purposeful in the selection of the parameters it directed BC Hydro to use in its planning process and must have understood those parameters would create the appearance of a capacity shortfall, which BC Hydro would then be forced to fill with incremental Firm energy. Government was also purposeful when the only option it left BC Hydro was to buy that energy from IPPs.

Over purchasing 8,500 GWh/year does not mean BC Hydro would sell that amount into the Mid-C market. IPPs are subject to variations in water and wind conditions and often the actual power presented is less than the contracted amount. Also, BC Hydro tries to manage its dispatchable resources to reduce the surplus so it can avoid selling expensive IPP energy into a Mid-C market that is depressed during Freshet.

At the end of 2009, the world was feeling the consequences of the 2008 financial downturn, and shale gas and fracking had depressed the natural gas market and market prices for energy with it. The B.C. forest industry had seen major closures, which impacted industrial demands for electricity and overall BC Hydro load by 6.4%.

If Government had reacted to the market events, changes in load/demand, or the advice of staff, direction to BC Hydro could have changed and BC Hydro could have avoided buying 8,500 GWh of energy it didn't need.

The list following shows the existing IPPs sorted by EPA signing date, with the newest EPAs at the top. The government direction impacting BC Hydro's energy planning occurred in 2007. BC Hydro attempted to comply by issuing five calls over two years, including the 2010 Clean Power Call and the Standing Offer Program. Logically, BC Hydro's response to Government's directions would be the IPP projects from those five calls. Accordingly, there is an illustrative break in the listing showing the EPAs from those five calls. While there is no way to prove direct causation, it appears reasonable to assume these EPAs represent BC Hydro's response to government's directions (the "**Response EPAs**").

Current Electricity Purchase Agreements with BC Hydro

Exemptions from BCUC review are highlighted yellow

Project Name	Call	Project Status	EPA Effective Date	Resource Type	Annual Energy (GWh)	Cumulative Annual Energy (GWh/y)	BCUC Review (post Minister's Order M-22-9801-A1) or Existing Exemption
Tsilhqot'in Solar Farm	2016 Micro-SOP	Pre-COD	8-Aug-18	Solar	2	2	Exempt: Clean Energy Act, s. 7 (1)(h)
Lorenzetta Creek Hydroelectric Project	2010 SOP	Post-COD	28-Sep-16	Non-Storage Hydro	10	12	Exempt: Clean Energy Act, s. 7 (1)(h)
Silversmith Power & Light	2016 NEPA	Post-COD	22-Jul-16	Non-Storage Hydro	1	13	Exempt: B.C. Reg 204/2016
Serpentine Creek Hydro	2010 SOP	Pre-COD	13-Jun-16	Non-Storage Hydro	31	44	Exempt: Clean Energy Act, s. 7 (1)(h)

Project Name	Call	Project Status	EPA Effective Date	Resource Type	Annual Energy (GWh)	Cumulative Annual Energy (GWh/y)	BCUC Review (post Minister's Order M-22-9801-A1) or Existing Exemption
Clemina Creek Hydro	2010 SOP	Pre-COD	18-Apr-16	Non-Storage Hydro	36	80	Exempt: Clean Energy Act, s. 7 (1)(h)
Hunter Creek Run-of-River Hydroelectric Project	2010 SOP	Post-COD	31-Mar-16	Non-Storage Hydro	37	117	Exempt: Clean Energy Act, s. 7 (1)(h)
Winchie Creek Hydro	2010 SOP	Post-COD	24-Feb-16	Non-Storage Hydro	11	128	Exempt: Clean Energy Act, s. 7 (1)(h)
Moose Lake Wind Project	2010 SOP	Pre-COD	22-Dec-15	Wind	56	184	Exempt: Clean Energy Act, s. 7 (1)(h)
Houweling Nurseries (Delta) Cogeneration	2014 NEPA	Post-COD	28-Apr-15	Gas Fired Thermal	65	249	Exempt: B.C. Reg 182/2014
Pennask Wind Farm	2010 SOP	Post-COD	7-Apr-15	Wind	50	299	Exempt: Clean Energy Act, s. 7 (1)(h)
Shinish Creek Wind Farm	2010 SOP	Post-COD	7-Apr-15	Wind	55	353	Exempt: Clean Energy Act, s. 7 (1)(h)
Wedgemount Creek IPP	2010 SOP	Pre-COD	6-Mar-15	Non-Storage Hydro	20	373	Exempt: Clean Energy Act, s. 7 (1)(h)
Tolko Kelowna Cogeneration	2010 SOP	Post-COD	24-Nov-14	Biomass	11	384	Exempt: Clean Energy Act, s. 7 (1)(h)
SunMine	2010 SOP	Post-COD	2-Jul-14	Solar	2	386	Exempt: Clean Energy Act, s. 7 (1)(h)
McIntosh Creek Waterpower Project	2010 SOP	Post-COD	8-Apr-14	Non-Storage Hydro	4	390	Exempt: Clean Energy Act, s. 7 (1)(h)
Nanaimo Reservoir #1 Energy Recovery	2010 SOP	Post-COD	6-Feb-14	ERG	1	391	Exempt: Clean Energy Act, s. 7 (1)(h)
Cache Creek Landfill Gas Utilization Plant	2010 SOP	Post-COD	5-Dec-13	Biogas	36	427	Exempt: Clean Energy Act, s. 7 (1)(h)
Intercon Green Power	2010 IPO	Post-COD	10-Apr-13	Biomass	73	500	Exempt: Clean Energy Act, s. 7 (1)(f)
Haa-ak-suuk Creek Hydro	2010 SOP	Post-COD	27-Feb-13	Non-Storage Hydro	21	520	Exempt: Clean Energy Act, s. 7 (1)(h)
Northwood Green Power	2010 IPO	Post-COD	19-Dec-12	Biomass	91	611	Exempt: Clean Energy Act, s. 7 (1)(f)
Squamish Power Project	2010 SOP	Post-COD	16-Oct-12	Storage Hydro	11	622	Exempt: Clean Energy Act, s. 7 (1)(h)
Fraser Richmond Soil and Fibre	2010 CBB	Post-COD	14-Feb-12	Biogas	8	630	Exempt: B.C. Reg. 45/2012
Harmac Biomass	2010 IPO	Post-COD	7-Dec-11	Biomass	209	839	Exempt: Clean Energy Act, s. 7 (1)(f)
Fort St. James Green Energy	2010 Bio Energy Ph 2	Post-COD	1-Dec-11	Biomass	304	1,143	Exempt: Clean Energy Act, s. 7 (1)(e)
Merritt Green Energy	2010 Bio Energy Ph 2	Post-COD	1-Dec-11	Biomass	304	1,446	Exempt: Clean Energy Act, s. 7 (1)(e)
McLymont Creek	2010 NEPA	Post-COD	2-Nov-11	Non-Storage Hydro	244	1,691	Exempt: Clean Energy Act, s. 7 (1)(a)
Volcano Creek	2010 NEPA	Post-COD	2-Nov-11	Non-Storage Hydro	51	1,741	Exempt: Clean Energy Act, s. 7 (1)(a)
East Twin Creek Hydro	2011 NEPA	Post-COD	1-Nov-11	Non-Storage Hydro	6	1,747	Reviewed: BCUC Order No. E-20-07
Chetwynd Biomass	2010 Bio Energy Ph 2	Post-COD	29-Sep-11	Biomass	96	1,844	Exempt: Clean Energy Act, s. 7 (1)(e)
Fraser Lake Biomass	2010 Bio Energy Ph 2	Post-COD	29-Sep-11	Biomass	96	1,940	Exempt: Clean Energy Act, s. 7 (1)(e)

Project Name	Call	Project Status	EPA Effective Date	Resource Type	Annual Energy (GWh)	Cumulative Annual Energy (GWh/y)	BCUC Review (post Minister's Order M-22-9801-A1) or Existing Exemption
South Cranberry Creek - R	2010 SOP	Post-COD	29-Sep-11	Non-Storage Hydro	6	1,946	Exempt: Clean Energy Act, s. 7 (1)(h)
Greater Nanaimo PCC Cogeneration	2010 SOP	Post-COD	16-Jun-11	Biogas	2	1,948	Exempt: Clean Energy Act, s. 7 (1)(h)
Conifex Green Energy	2011 NEPA	Post-COD	10-Jun-11	Biomass	220	2,168	Reviewed: BCUC Order No. G-40-12
Kamloops Green Energy	2010 IPO	Post-COD	6-Jun-11	Biomass	288	2,456	Exempt: Clean Energy Act, s. 7 (1)(f)
LP Golden Biomass	2010 SOP	Post-COD	6-May-11	Biomass	4	2,460	Exempt: Clean Energy Act, s. 7 (1)(h)
Powell River Generation	2010 IPO	Post-COD	18-Feb-11	Biomass	158	2,617	Exempt: Clean Energy Act, s. 7 (1)(f)
Cariboo Pulp and Paper	2010 IPO	Post-COD	13-Dec-10	Biomass	172	2,789	Exempt: Clean Energy Act, s. 7 (1)(f)
Waneta Expansion	2010 NEPA	Post-COD	1-Oct-10	Non-Storage Hydro	627	3,417	Exempt: B.C. Reg 254/2010 (M-230)
Howe Sound Green Energy	2010 IPO	Post-COD	7-Sep-10	Biomass	400	3,817	Exempt: Clean Energy Act, s. 7 (1)(f)
Box Canyon	2010 CPC	Post-COD	13-Aug-10	Non-Storage Hydro	47	3,864	Exempt: Clean Energy Act, s. 7 (1)(g)
Castle Creek (formerly Benjamin Creek)	2010 CPC	Post-COD	13-Jul-10	Non-Storage Hydro	34	3,898	Exempt: Clean Energy Act, s. 7 (1)(g)
Bremner - Trio	2010 CPC	Pre-COD	25-Jun-10	Non-Storage Hydro	168	4,066	Exempt: Clean Energy Act, s. 7 (1)(g)
Crowsnest Pass	2010 CPC	Post-COD	25-Jun-10	ERG	65	4,131	Exempt: Clean Energy Act, s. 7 (1)(g)
Long Lake Hydro	2010 CPC	Post-COD	25-Jun-10	Storage Hydro	153	4,284	Exempt: Clean Energy Act, s. 7 (1)(g)
Forrest Kerr Hydroelectric	2010 NEPA	Post-COD	28-May-10	Non-Storage Hydro	935	5,219	Exempt: Clean Energy Act, s. 7 (1)(a)
Culliton Creek	2010 CPC	Post-COD	3-May-10	Non-Storage Hydro	74	5,293	Exempt: Clean Energy Act, s. 7 (1)(g)
Cape Scott (formerly Knob Hill Wind)	2010 CPC	Post-COD	30-Apr-10	Wind	316	5,609	Exempt: Clean Energy Act, s. 7 (1)(g)
Skookum Power (aka Mamquam Skookum)	2010 CPC	Post-COD	30-Apr-10	Non-Storage Hydro	102	5,711	Exempt: Clean Energy Act, s. 7 (1)(g)
Boulder Creek	2010 CPC	Post-COD	22-Apr-10	Non-Storage Hydro	92	5,803	Exempt: Clean Energy Act, s. 7 (1)(g)
Big Silver - Shovel Creek	2010 CPC	Post-COD	22-Apr-10	Non-Storage Hydro	159	5,962	Exempt: Clean Energy Act, s. 7 (1)(g)
Dasque - Middle	2010 CPC	Post-COD	22-Apr-10	Non-Storage Hydro	81	6,043	Exempt: Clean Energy Act, s. 7 (1)(g)
Jamie Creek	2010 CPC	Post-COD	22-Apr-10	Non-Storage Hydro	74	6,117	Exempt: Clean Energy Act, s. 7 (1)(g)
Kokish River	2010 CPC	Post-COD	22-Apr-10	Non-Storage Hydro	175	6,292	Exempt: Clean Energy Act, s. 7 (1)(g)
Meikle Wind	2010 CPC	Post-COD	22-Apr-10	Wind	541	6,833	Exempt: Clean Energy Act, s. 7 (1)(g)
Northwest Stave River	2010 CPC	Post-COD	22-Apr-10	Non-Storage Hydro	65	6,898	Exempt: Clean Energy Act, s. 7 (1)(g)
Quality Wind	2010 CPC	Post-COD	22-Apr-10	Wind	477	7,375	Exempt: Clean Energy Act, s. 7 (1)(g)

Project Name	Call	Project Status	EPA Effective Date	Resource Type	Annual Energy (GWh)	Cumulative Annual Energy (GWh/y)	BCUC Review (post Minister's Order M-22-9801-A1) or Existing Exemption
Narrows Inlet	2010 CPC	Pre-COD	22-Apr-10	Non-Storage Hydro	148	7,522	Exempt: Clean Energy Act, s. 7 (1)(g)
Tretheway Creek	2010 CPC	Post-COD	22-Apr-10	Non-Storage Hydro	81	7,603	Exempt: Clean Energy Act, s. 7 (1)(g)
Upper Lillooet River	2010 CPC	Post-COD	22-Apr-10	Non-Storage Hydro	334	7,937	Exempt: Clean Energy Act, s. 7 (1)(g)
Jimmie Creek (Upper Toba Valley)	2010 CPC	Post-COD	22-Apr-10	Non-Storage Hydro	174	8,111	Exempt: Clean Energy Act, s. 7 (1)(g)
Lower Bear Hydro	2008 SOP	Post-COD	21-Dec-09	Non-Storage Hydro	46	8,157	Exempt: Clean Energy Act, s. 7 (1)(h); EPA originally reviewed BCUC Order E-19-10
Upper Bear Hydro	2008 SOP	Post-COD	21-Dec-09	Non-Storage Hydro	73	8,230	Exempt: Clean Energy Act, s. 7 (1)(h); EPA originally reviewed BCUC Order E-19-10
Cedar Road LFG	2008 SOP	Post-COD	9-Sep-09	Biogas	11	8,241	Exempt: Clean Energy Act, s. 7 (1)(h); EPA originally reviewed BCUC Order E-19-09
Skookumchuck Power Project	2009 NEPA	Post-COD	13-Aug-09	Biomass	267	8,508	Reviewed: BCUC Order No. E-16-09
Armstrong Wood Waste Co-Gen (RVG)	2009 NEPA	Post-COD	13-Aug-09	Biomass	163	8,671	Section 71 application currently before BCUC for short-term extension; original EPA reviewed BCUC Order No. E-17-09
Canoe Creek Hydro	2008 SOP	Post-COD	7-Aug-09	Non-Storage Hydro	16	8,687	Exempt: Clean Energy Act, s. 7 (1)(h); EPA originally reviewed BCUC Order E-6-10
Fitzsimmons Creek	2008 SOP	Post-COD	18-Jun-09	Non-Storage Hydro	36	8,723	Exempt: Clean Energy Act, s. 7 (1)(h); EPA originally reviewed BCUC Order E-11-09
PGP Bio Energy Project	2008 Bio Energy	Post-COD	4-Feb-09	Biomass	123	8,846	Reviewed: BCUC Order No. E-8-09
Celgar Green Energy	2008 Bio Energy	Post-COD	27-Jan-09	Biomass	242	9,088	Reviewed: BCUC Order No. E-8-09
Cypress Creek	2008 SOP	Post-COD	21-Jan-09	Non-Storage Hydro	12	9,100	Exempt: Clean Energy Act, s. 7 (1)(h)
Dokie Wind	2009 NEPA	Post-COD	31-Aug-06	Wind	375	9,475	Reviewed: BCUC Order No. E-14-09

Kemano	2007 NEPA	Post-COD	13-Aug-07	Storage Hydro	3,307	12,782	Reviewed: BCUC Order No. E-3-08
Barr Creek	2006 Call	Post-COD	31-Aug-06	Non-Storage Hydro	16	12,798	Reviewed: BCUC Order No. E-7-06
Bear Mountain Wind Park	2006 Call	Post-COD	31-Aug-06	Wind	197	12,995	Reviewed: BCUC Order No. E-7-06
Bone Creek Hydro	2006 Call	Post-COD	31-Aug-06	Non-Storage Hydro	81	13,076	Reviewed: BCUC Order No. E-7-06
Brilliant Expansion 2	2006 Call	Post-COD	31-Aug-06	Storage Hydro	226	13,302	Exempt: B.C. Reg 254/2010 (M-230)

Project Name	Call	Project Status	EPA Effective Date	Resource Type	Annual Energy (GWh)	Cumulative Annual Energy (GWh/y)	BCUC Review (post Minister's Order M-22-9801-A1) or Existing Exemption
Eldorado Reservoir	2006 Call	Post-COD	31-Aug-06	Storage Hydro	4	13,306	Reviewed: BCUC Order No. E-7-06
East Toba and Montrose	2006 Call	Post-COD	31-Aug-06	Non-Storage Hydro	715	14,021	Reviewed: BCUC Order No. E-7-06
150 Mile House ERG	2006 Call	Post-COD	31-Aug-06	ERG	34	14,055	Reviewed: BCUC Order No. E-7-06
Kwoiek Creek Hydroelectric	2006 Call	Post-COD	31-Aug-06	Non-Storage Hydro	223	14,278	Reviewed: BCUC Order No. E-7-06
Kwalsa Energy	2006 Call	Post-COD	31-Aug-06	Non-Storage Hydro	384	14,662	Reviewed: BCUC Order No. E-7-06
Lower Clowhom	2006 Call	Post-COD	31-Aug-06	Non-Storage Hydro	48	14,710	Reviewed: BCUC Order No. E-7-06
Raging River 2	2006 Call	Post-COD	31-Aug-06	Storage Hydro	30	14,740	Reviewed: BCUC Order No. E-7-06
Cranberry Creek Power	2006 Call	Post-COD	31-Aug-06	Non-Storage Hydro	9	14,749	Reviewed: BCUC Order No. E-7-06
Sakwi Creek Run of River	2006 Call	Post-COD	31-Aug-06	Non-Storage Hydro	21	14,770	Reviewed: BCUC Order No. E-7-06
Savona ERG	2006 Call	Post-COD	31-Aug-06	ERG	41	14,811	Reviewed: BCUC Order No. E-7-06
Tyson Creek Hydro	2006 Call	Post-COD	31-Aug-06	Storage Hydro	54	14,865	Reviewed: BCUC Order No. E-7-06
Upper Clowhom	2006 Call	Post-COD	31-Aug-06	Non-Storage Hydro	48	14,913	Reviewed: BCUC Order No. E-7-06
Upper Stave Energy	2006 Call	Post-COD	31-Aug-06	Non-Storage Hydro	264	15,177	Reviewed: BCUC Order No. E-7-06
Ashlu Creek Water Power	2003 GPG	Post-COD	5-Nov-03	Non-Storage Hydro	269	15,446	Reviewed: BCUC Order No. E-2-04
Brilliant Expansion 1	2003 GPG	Post-COD	5-Nov-03	Storage Hydro	203	15,648	Exempt: B.C. Reg 254/2010 (M-230)
China Creek Small Hydroelectric	2003 GPG	Post-COD	5-Nov-03	Non-Storage Hydro	25	15,673	Reviewed: BCUC Order No. E-2-04
South Cranberry Creek	2003 GPG	Post-COD	5-Nov-03	Non-Storage Hydro	26	15,699	Reviewed: BCUC Order No. E-2-04
Vancouver Landfill Gas Utilization - Ph 2	2003 GPG	Post-COD	5-Nov-03	Biogas	15	15,715	Reviewed: BCUC Order No. E-2-04
Zeballos Lake	2003 GPG	Post-COD	5-Nov-03	Storage Hydro	93	15,807	Reviewed: BCUC Order No. E-2-04
Hartland Landfill Gas Utilization	2000 RFP	Post-COD	1-May-03	Biogas	15	15,822	Exempt: Minister's Order M-22-9801-A1
Upper Mamquam Hydro	2001 GT 40 GWh	Post-COD	27-Sep-02	Non-Storage Hydro	108	15,930	Reviewed: BCUC Order No. E-1-04
Rutherford Creek Hydro	2001 GT 40 GWh	Post-COD	12-Jun-02	Non-Storage Hydro	172	16,102	Reviewed: BCUC Order No. E-1-04
Pingston Creek	2001 GT 40 GWh	Post-COD	10-May-02	Non-Storage Hydro	193	16,295	Reviewed: BCUC Order No. E-10-03
Brandywine Creek Small Hydro	2001 LT 40 GWh	Post-COD	4-Jan-02	Non-Storage Hydro	34	16,329	Reviewed: BCUC Order No. E-10-03
Furry Creek	2001 LT 40 GWh	Post-COD	21-Dec-01	Non-Storage Hydro	40	16,369	Reviewed: BCUC Order No. E-10-03
Hauer Creek (aka Tete)	2001 LT 40 GWh	Post-COD	21-Dec-01	Non-Storage Hydro	13	16,381	Reviewed: BCUC Order No. E-2-04
Marion 3 Creek	2001 LT 40 GWh	Post-COD	21-Dec-01	Non-Storage Hydro	18	16,399	Reviewed: BCUC Order No. E-2-04

Project Name	Call	Project Status	EPA Effective Date	Resource Type	Annual Energy (GWh)	Cumulative Annual Energy (GWh/y)	BCUC Review (post Minister's Order M-22-9801-A1) or Existing Exemption
Eagle Lake C2 Micro Hydro	2001 LT 40 GWh	Post-COD	21-Dec-01	Non-Storage Hydro	1	16,400	Reviewed: BCUC Order No. E-11-18; EPA originally reviewed BCUC Order E-10-03
South Sutton Creek	2001 LT 40 GWh	Post-COD	21-Dec-01	Non-Storage Hydro	26	16,426	Reviewed: BCUC Order No. E-2-04
Vancouver Landfill Gas Utilization - Ph 1	2001 LT 40 GWh	Post-COD	21-Dec-01	Biogas	40	16,466	Reviewed: BCUC Order No. E-10-03
Mears Creek	2001 LT 40 GWh	Post-COD	19-Dec-01	Non-Storage Hydro	20	16,485	Reviewed: BCUC Order No. E-1-04
McNair Creek Hydro	2001 LT 40 GWh	Post-COD	18-Dec-01	Non-Storage Hydro	38	16,523	Reviewed: BCUC Order No. E-1-04
Hystad Creek Hydro	2000 RFP	Post-COD	3-Aug-01	Non-Storage Hydro	20	16,543	Reviewed: BCUC Order No. E-20-07
Miller Creek Power	2000 RFP	Post-COD	28-Mar-01	Non-Storage Hydro	118	16,661	Exempt: Minister's Order M-22-9801-A1
Arrow Lakes Hydro	1998 NEPA	Post-COD	16-Dec-98	Storage Hydro	767	17,428	Exempt: B.C. Reg 254/2010 (M-230)
Island Generation	1994 RFP	Post-COD	29-Sep-98	Gas Fired Thermal	2,300	19,728	Exempt: Minister's Order M-22-9801-A1
Robson Valley (Ptarmigan Creek)	1989 LT 5 MW	Post-COD	18-Oct-91	Non-Storage Hydro	26	19,755	Exempt: Minister's Order M-22-9801-A1
Mamquam Hydro	1988 GT 5 MW	Post-COD	29-Aug-90	Non-Storage Hydro	250	20,005	Exempt: Minister's Order M-22-9801-A1
Walden North	1989 LT 5 MW	Post-COD	16-Aug-90	Non-Storage Hydro	54	20,059	Exempt: Minister's Order M-22-9801-A1; Section 71 application currently before BCUC for new replacement EPA
NWE Williams Lake WW	1988 GT 5 MW	Post-COD	30-Jun-90	Biomass	545	20,604	Section 71 application currently before BCUC; original EPA reviewed but superseded by Minister's Order M-22-9801-A1
McMahon Generating	1988 GT 5 MW	Post-COD	10-Apr-90	Gas Fired Thermal	840	21,444	Exempt: Minister's Order M-22-9801-A1
Coats IPP	1985 NEPA	Post-COD	10-May-85	Non-Storage Hydro	1	21,444	Exempt: Minister's Order M-22-9801-A1

The right-hand column confirms whether or not the decision to enter into the EPA was subject to BCUC review or exempted from BCUC oversight. This table clearly shows the impact of Government's decision to "modernize" BCUC as discussed in Section 25.

The Response EPAs represent approximately 9,500 GWh of additional contracted energy. These EPAs act as a proxy for the impact. Of note, total energy contracted for under the Response EPAs includes both Firm and non-Firm energy, whereas the policy directive demanded BC Hydro deliver 8,500 GWh in Firm energy. BC Hydro was trying to buy 8,500 GWh of Firm energy, but likely managed to buy only 9,500 GWh of blended energy, equivalent to approximately 8,075[7] GWh of Firm energy.

7 based on a BC Hydro planning assumption that the IPP portfolio is 85% Firm

Considering that ~25% of the energy coming from the Response EPAs is Firm energy from Bioenergy projects, a typical blended energy rate (Firm and non-Firm) at the time could have been approximately $110/MWh.[8]

Estimate of the impact of Government's policy directives based on the Response EPAs

Average cost of 9,500 GWh of blended energy acquired in 2009 is assumed to be $110/MWh

Estimated market value of this surplus energy, if sold at Mid-C is assumed to be $25 /MWh
(ignoring time of delivery, the cost of BC Hydro firming the Intermittent energy, line losses, transmission costs, etc.)

The incremental cost of the energy overbuy would then be

($110-$25) / MWh x 9,500 GWh/y = **$808 million per year**

The average EPA in the period is assumed to carry a 30-year term.

Total impact of the policy directive can be estimated as:

($808 million * 30 years) = **$24.2 billion over 30 years.**

Assuming the annual impact of the over-buy will be felt for some 20 years and the impact of the policy directives would be estimated as:

($808 million * 20 years) = **$16.2 billion over 20 years.**

Assuming the Response EPAs act as a proxy for BC Hydro's response to Government's policy directions, an impact of $16.2 billion over 20 years would be indicated.

The primary issue identified in this report is that government gave BC Hydro directions as to the parameters it should use in energy planning, understanding that when BC Hydro applied those parameters, the planning process would indicate an energy deficit of 8,500 GWh (later 11,500 GWh). Government understood BC Hydro would then immediately procure that new energy, as its mandate dictates that BC Hydro must have Firm energy available to meet load, before the load appears.

Accordingly, this report estimates the cost of this over-buy of energy BC Hydro did not need at the time of Government's directions from two directions.

The predicted impact of Government's policy directives over 20 years based on the assumption that policy changes resulted in the purchase of 8,500 GWh of Firm energy is estimated as $17 billion.

The predicted impact of Government's policy directives over 20 years based on the cost of the Response EPAs (9,500 GWh of blended energy or approximately 8,076 GWh of Firm energy) is estimated as $16.2 billion.

This report considers the estimate based on the Response EPAs to be more solid as it is based on fewer impactful assumptions. The broad estimate of the cost of the policy directions supports the reasonableness of the estimate based on the Response EPAs

8 Slightly higher than the levelized price of approximately $101/MWh for total energy reported for the 2010 Clean Power Call ($2009) to account for the high proportion of Firm energy.

This report estimates the impact of government's direction that BC Hydro should over-buy energy to be $16.2 billion (the "Estimate").

To be clear, this Estimate is the cost to ratepayers resulting from BC Hydro being told to buy energy it did not need, calculated over the period during which we expect that energy to be surplus to load.

In Fiscal 2018, the total cost of IPP energy to BC Hydro was $1.4 billion. The over-buy accounts for an estimated $808 million per year, which is a cost now borne by ratepayers. Revenue from residential customers accounts for 43% of total revenue for BC Hydro. If 43% of $808 million were divided equally among BC Hydro's approximately 1.8 million residential customers, that means each residential account is paying about $200 for the over-buy this year, and will pay in excess of $4,000 over 20 years.

This Estimate is conservative for two reasons: it does not reflect that BC Hydro paid far above the market value to acquire this energy and it does not reflect the impact of the inflation provisions set in the EPAs.

Underlying the Estimate is an assumption that the energy associated with the Response EPAs will be surplus for 20 years. After that point, BC Hydro is assumed to have load to use 9,500 GWh of energy over the remaining ten years of the term of the EPAs. BC Hydro then has an aggregate of 95,000 GWh (being 10 years * 9,500 GWh). It is paying about $110 /MWh to buy the energy. It is selling this energy to ratepayers at perhaps $60 /MWh (a loss of $4.8 billion). It could have bought the same energy at Mid-C for about $25 /MWh and sold it to ratepayers at $60 /MWh (a profit of $3.3 billion). We should not lose sight of the three NTL EPAs that have 60-year terms. These three EPAs commit BC Hydro to 1,230 GWh of energy for an additional 30 years and increase to future loss by $1.8 billion.

The impact of Government's direction to over-buy will continue until the EPAs reach term, even if BC Hydro has load and is able to use the energy.

After the 20 years during which the assumption is that all energy is surplus, it is assumed that BC Hydro will have 9,500 GWh for 10 years and then 1,230 GWh from the NTL EPAs for an additional 30 years, all of which can be sold to ratepayers, but at a loss. The estimated impact over and above the $16.2 billion is $6.6 billion:

9,500 GWh over 10 years	$4.8 billion
1,230 GWh NTL EPAs over 30 years	$1.8 billion
Estimated impact of excess energy rates	**$6.6 billion**

Inflation impacts are discussed in Section 35.

Following are two graphs showing actual and projected IPP payments. These graphs reflect all IPP EPAs, not just the Response EPAs. Figure 11 depicts the annual payment commitment BC Hydro has under the EPAs. Figure 12 depicts the aggregate cost of those EPA payments. Effectively all the financial impact followed the pronouncement of the 2002 Energy Plan. Annual IPP payments are shown as $1.4 billion in 2018 and are projected to peak in about 2030 at just under $1.7 billion. Figure 13 shows the aggregate cost approaching $66 billion in 2075 (when the 3 NTL EPAs finally reach their end of term).

Today, BC Hydro's EPA portfolio includes 105 contracts signed since 2002, representing a forecast financial commitment of over $47 billion. The portfolio also includes 25 EPAs signed before 2002, representing a future financial commitment of $4 billion. Clearly, the point of financial impact was the pronouncement of the 2002 Energy Plan.

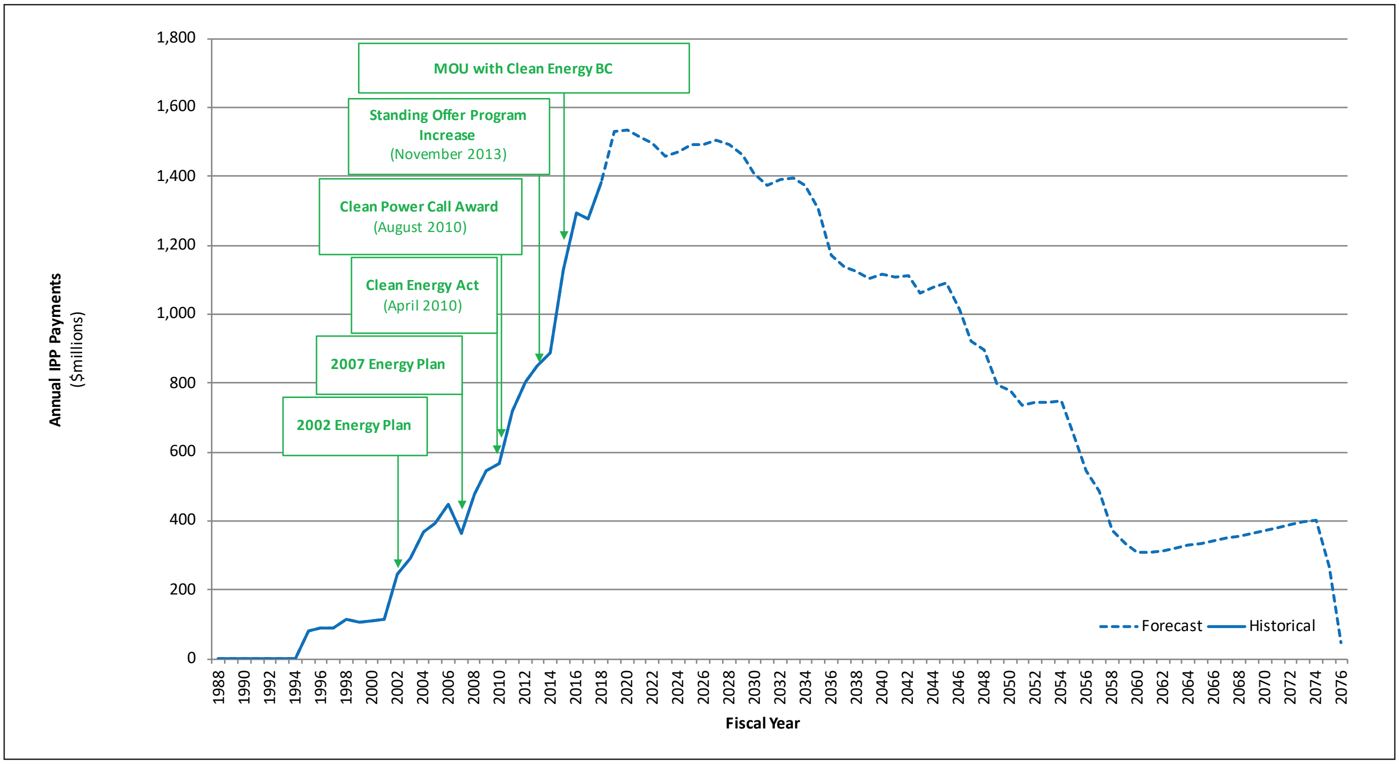


Figure 11: BC Hydro Annual IPP Payments–Actual and Projected

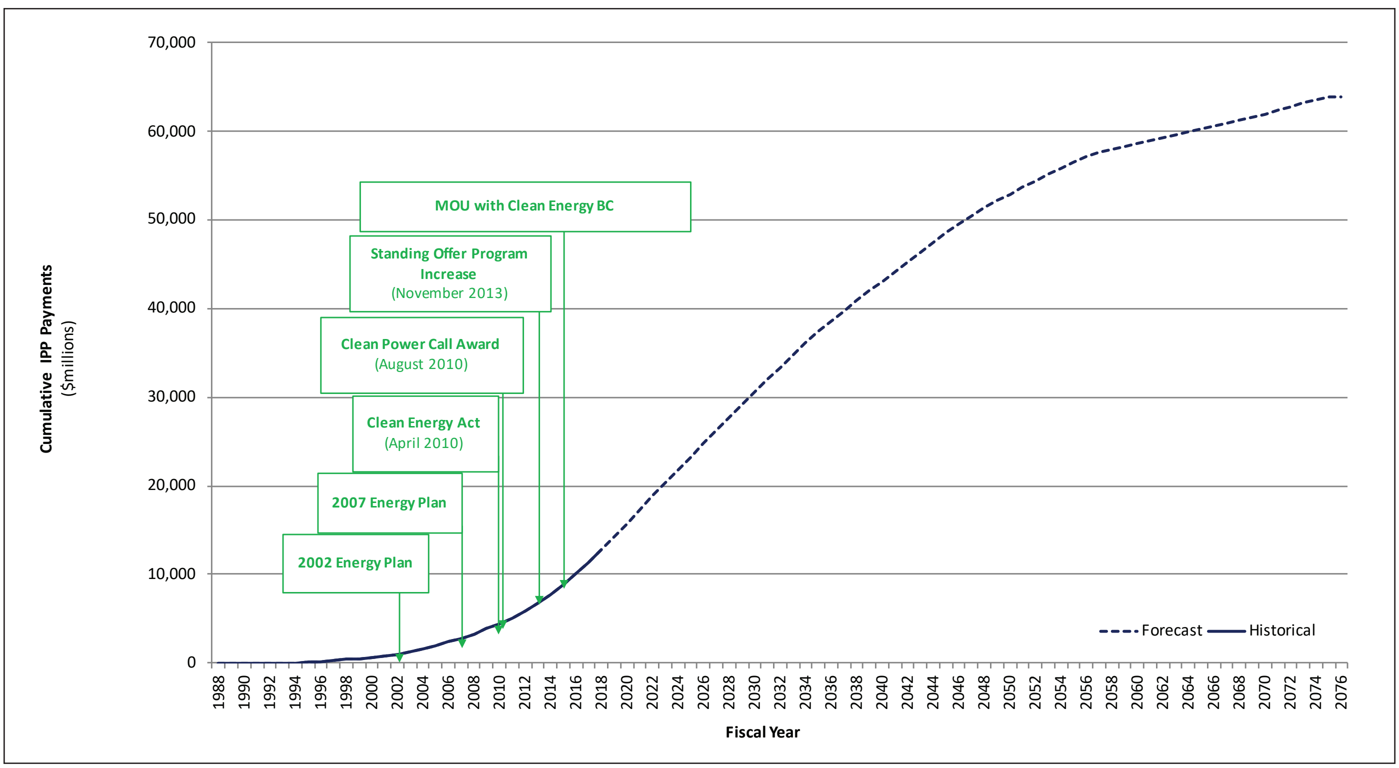


Figure 12: BC Hydro Cumulative IPP Payments–Actual and Projected

The Response EPAs will likely cost ratepayers an Estimated $16.2 billion over 20 years. BC Hydro reports that $3.2 billion of that total has been incurred to March 31, 2018. The Response EPAs, including the three NTL EPAs with sixty-year terms commit BC Hydro to energy purchases (2019 and beyond) of another $38.7 billion, or $41.9 billion in total. Once

BC Hydro is no longer in energy surplus (in the 2030s), this energy can to sold to ratepayers and the EPA contract payment obligations shown here will be moderated by the payments from ratepayers. As shown above, once BC Hydro is no longer in energy surplus, approximately half of the cost of buying this energy is recovered from ratepayers and the excess price BC Hydro is paying for this energy is revealed.

32) Price Competition and the Signals to the Market

The analysis demonstrates that Government directions impacted BC Hydro's energy planning to give the appearance of an energy shortfall of 8,500 GWh/year, with a resulting financial impact well in excess of $17 billion.

The real question is why did the energy cost so much more than what it was worth in the market at Mid-C? The answer is that Government demanded BC Hydro accelerate its IPP purchases.

Following each energy procurement, BC Hydro published a summary report with a section on cost effectiveness. In this section BC Hydro compares the results of the current call to the results of the last BC Hydro call; the current call is typically found to be "in line."

BC Hydro does not compare call results to either the value of the energy at Mid-C rates or at the costs for energy from the Heritage Assets. Pricing the calls at market value or at historic costs ceased to be an option following the 2007 Energy Plan. As such, any comparison would only serve to cast the calls in an unfavourable light.

BC Hydro reported consistency of results as if it were a proxy for good value, but consistency is not equal to good value for money. For example, the 2010 Clean Power Call RFP provided a term sheet that carried the concepts of seasonality and time of day pricing, first seen in the 2006 calls. Proponents were instructed to propose a fixed price for Firm energy and given the option of pricing non-Firm energy either at market value (Mid-C) or at the fixed price set in the term sheet.

The term sheet would be read by the market as an indication of BC Hydro's receptivity to prices on Firm energy; Firm energy is worth more than non-Firm, hence the term sheet prices for non-Firm energy would be read as a "floor" for Firm energy and an invitation for proponents to bid more than that "floor" for that Firm energy.

Signalling to the market took two forms.

As noted, the treatment of non-Firm power signalled BC Hydro was comfortable with rates for Firm energy higher than the quoted rates for non-Firm energy. Proponents which follow BC Hydro's applications to BCUC would also draw insight from BC Hydro's submissions for the 2008 LTAP which provided BC Hydro's cost estimates for long-term Firm energy supply as $124/MWh in 2008 constant dollars. It would be hard for the market to ignore that signal.

The calls also signalled the volume of the purchases that BC Hydro needed to make. If a marketplace has a huge number of participants, announcing to the market how much you need to buy has little effect on the prices offered. Proponents know there will be many proposals and to win, they need to put their best price forward.

However, if the market is limited (as is the case in the BC IPP market), price responds to an announcement of the size of the opportunity. Potential proponents know each other, either directly or through the industry association. They know who has a project advanced to the point it could bid. They all understand construction costs. When a proponent proposes a price in this situation, they don't propose the lowest price at which they can be profitable. They know there can be only a limited number of proposals, let's say 20. They know BC Hydro must select 15 of the potential 20 proposals if it is going to buy the amount of power it has announced it needs.

In this situation when you have signals as to the price BC Hydro is willing to pay and that a large volume of purchases is needed, proponents don't bid their lowest price: they bid a price they believe will place them into the group of 15 who will receive EPAs.

These signals to the market were likely required if BC Hydro was to achieve the speed of IPP uptake demanded by Government. It should therefore be no surprise that a demand for speed would increase prices.

The graph below shows the Firm energy pricing for IPP energy from different calls (with the exception of the 2003 GPG).

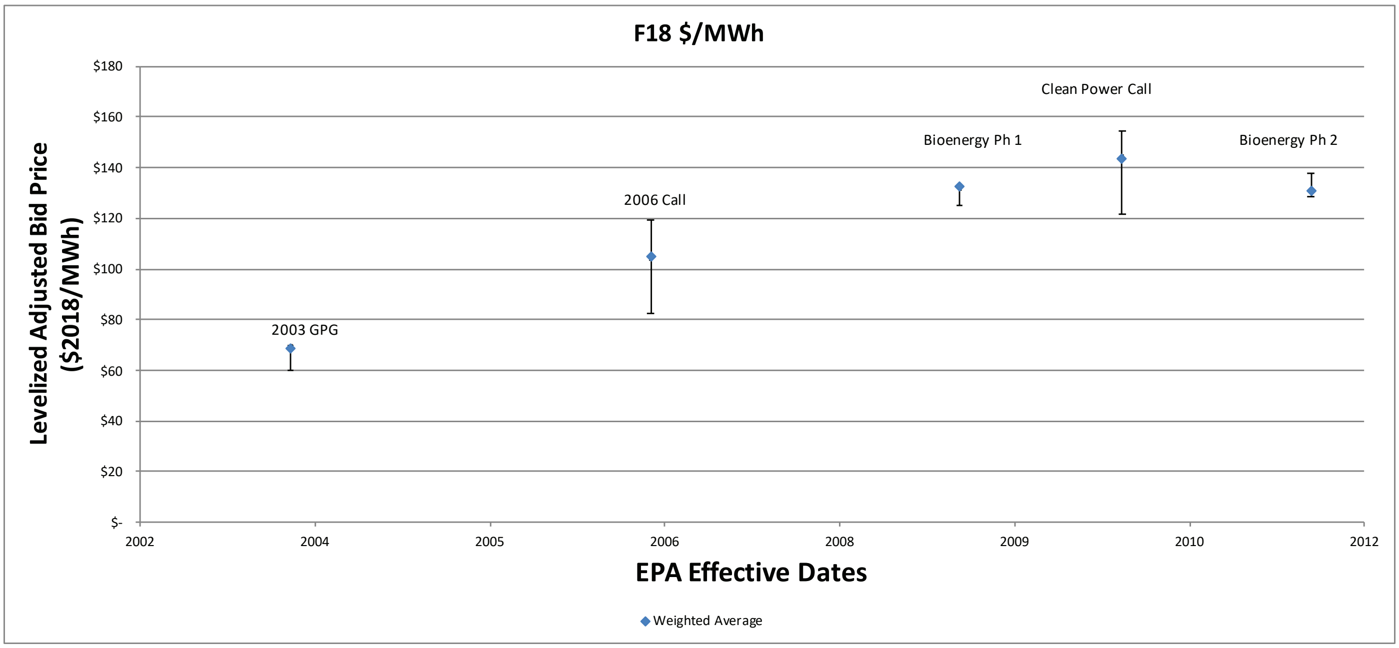


Figure 13: Range of Levelized Adjusted Bid Prices for Recent BC Hydro Calls

The graph presented in the section above shows how the Firm energy prices for IPP energy have increased over time and that the blended power rates on the recent calls came in at a range aligned with expectations BC Hydro had signalled to the market.

The graphs show prices rising over time and support the proposition that in a constrained market, with signals of price and volume, prices would be expected to show upward pressure as the market tests price tolerance; prices rise until the buyer is not prepared to continue to pay the "speed of uptake premium."

There is one important outlier; a project from the 2000 RFP we have named Anomaly Co. Anomaly Co. demonstrates that if Government hadn't tried to dictate the speed of IPP program uptake, BC Hydro could likely have negotiated many of the EPAs at a rate based directly on the Mid-C price and the financial issues of today would not have occurred. That said, IPP volumes would have been limited and would likely not have met Government's direction to BC Hydro to purchase large volumes of energy from IPPs.

33) Anomaly Co.

There is one anomalous IPP, which we will call Anomaly Co. to protect commercial confidentiality. Anomaly Co. responded to a call that was open during the period of record high Mid-C prices in the early 2000s. Anomaly Co. had the option to accept the general offer under the call (a rate in the $30-35 /MWh), but chose instead to base its EPA upon the Mid-C rate, believing as did the Government of the day, that rates during the energy crisis would hold and even trend upward. The California Energy Crisis ended and energy prices crashed, catching both the Government and Anomaly Co. off guard.

Despite the crash in the Mid-C market rate following the energy crisis, Anomaly Co. was constructed and has operated successfully from its COD through to today, over 15 years.

Anomaly Co. was sold to an investor in 2012, confirming it was still a viable proposition and an interesting investment opportunity at that time. Information respecting IPP construction costs and operating costs is difficult to locate in the public domain. That said, from the information that is available, it appears likely that the sale price in 2012 was similar to the construction cost invested by 2003. It appears the original owner of Anomaly Co. has recovered its construction costs from the sale and pocketed as revenue, the $32 million received under its EPA prior to the 2012 sale. So far, the new owner has been paid revenue in the range of $23 million since the sale.

The example of Anomaly Co. demonstrates that prior to the market change in 2009, there was likely an opportunity for BC Hydro to buy IPP power by simply putting out a call for proposals, with BC Hydro only offering to buy energy at its market value, the Mid-C rate. It also demonstrates that even the depressed Mid-C rates seen post-2009 are still sufficient to sustain the project and attract a new investor.

The Mid-C rates seen post 2009 (depressed by a glut of natural gas) would likely not generate new IPP projects. Rates in the range of the pre-2009 Mid-C rates would have supported an amount of IPP construction. Rates as high as those offered by BC Hydro were not necessary to generate construction; they were only necessary to meet the project volumes and project timing demanded by Government. Volume and speed costs money.

34) Electricity Purchase Agreements

For BC Hydro to meet the procurement targets directed by Government, it needed call processes that were easy for proponents to respond to and to qualify for. The procurements after 2007 delivered those attributes and succeeded in getting the proponents through the door.

The EPAs had five key features:

a. a fixed term,

b. a fixed commitment to buy on a take or pay basis,

c. no ability for BC Hydro to terminate except in the case of default of the proponent,

d. inflation protection, and

e. a rate structure influenced by cost of production, which is not tied to the market value of energy as represented by the Mid-C rate.

Features a. through d. and some form of clear pricing structure are required to make the EPA bankable.

The pricing structure has the impact of shifting the balance of risk towards or away from the proponent. Any pricing structure based on the Mid-C value of energy may shift the market risk to the proponent. This could lead to banks requesting increased equity/capital injections, to reduce the possible impact of market variability on the profitability of the project. That would reduce the speed of project uptake, as proponents would have more difficulty with financing.

Provincial directions made it clear the province wanted speed of approval and project initiation. To deliver on that direction, BC Hydro offered fixed price EPAs, with no reference to market value and signalled it was prepared to pay higher energy prices to achieve speed and volume. As previously discussed, the market responded with alacrity.

Previous independent legal reviews have confirmed BC Hydro cannot avoid the obligations created in the EPAs without a risk of breaching the contracts. Therefore, the scope of this review did not include repeating that analysis.

But there is hope. Even long-term EPAs ultimately expire. A few biomass projects have renewal provisions in their EPAs, with those provisions set as an option available to the biomass producer. BC Hydro staff confirm the vast majority of other EPAs are silent on the issue of renewal or extension. Government's practice is to offer to the existing lessee, a renewal of maturing crown leases on the commercial terms prevailing at the time.

Similarly, where the EPA is silent on renewal, an IPP would likely have an expectation that BC Hydro will offer an extension on some "commercial" basis. However, without a contractual obligation defining the basis of the renewal, BC Hydro would not be expected or compelled to offer renewal that is non-commercial or detrimental to BC Hydro.

EPA renewals are discussed in Section 44.

35) Inflation Provisions in the EPAs

Under the 1989 Less Than 5 MW RFP, BC Hydro offered to buy all energy generated at a set price of $30/MWh, with the offered price set to escalate at a fixed 3% (CPI in 1989 was above 4%). Figure 15 appearing below (which shows a start price of ~$35 for the average EPA in this call) indicates that the actual terms in each EPA may have varied from the terms of the original RFP, depending on when the EPA was signed.

While the Mid-C hub didn't exist in 1989, we understand that a ~$35/MWh price would have reflected market value on the day.

There is no corporate memory as to how this inflation adjustment/escalation strategy was set but given overt Government influence in BC Hydro's energy planning started after 2001, the design of this inflation adjustment should be considered a BC Hydro mistake.

Once the project is built, typically construction costs are sunk and not subject to inflation pressures. Only operating costs are subject to inflation. The limited market information available seems to indicate that operating costs typically average approximately 20% of the energy rate. Assuming 20% is a reasonable estimate, an offer to escalate the whole rate at a fixed 3% to provide for inflation would be equivalent to an offer to inflate the operating costs significantly more than the actual escalation experienced (five times more if the 20% assumption is valid).

The offer of an escalation clause in the 1989 LT 5 MW call could have been an expensive decision for BC Hydro, but luckily, the 1989 LT 5 MW call was relatively small, impacting only 390 MWh/yr.

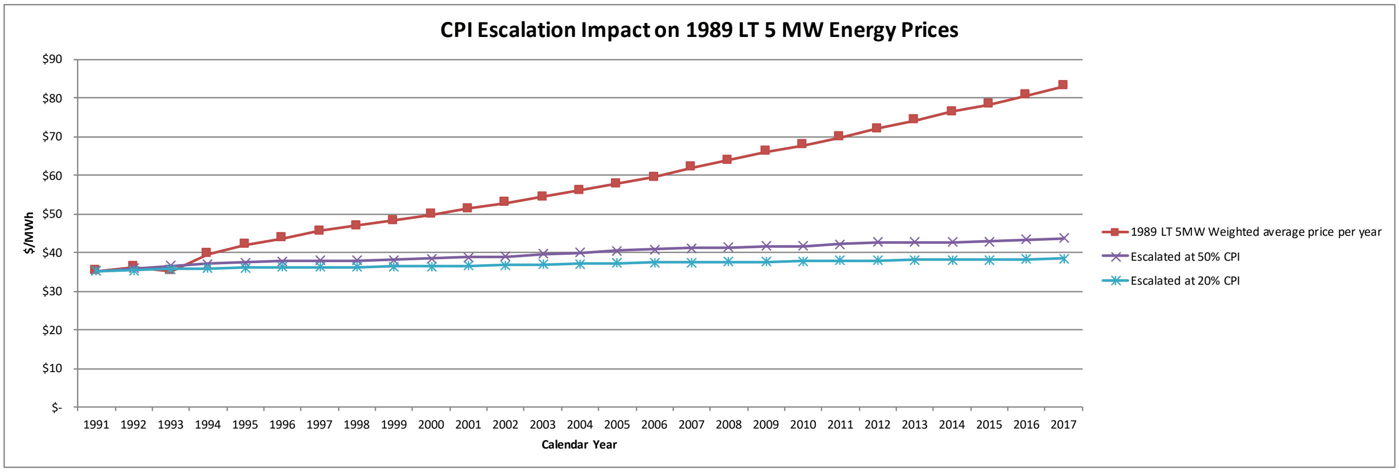


Figure 14: Indicative Pricing for 1989 LT 5 MW Call vs CPI Escalation Scenarios

This chart shows indicative pricing for EPAs from the 1989 call. Awards under this RFP were for small projects in the range of less than 100 KW to almost 17 MW. The energy price started at a price of ~$35/MWh depending upon when commercial operations started but has now grown with the 3% escalation provision to ~$80/MWh. BC Hydro is now at the point where it has negotiated renewals on several projects from this call.

If only the operating costs are subject to inflation and we assume they represent in this scenario 20% of the energy rate, offering full inflation coverage on only the operating costs would be the same as offering 20% inflation coverage on the whole rate. The "escalated at 20% of CPI" line shows the scenario where operating costs are assumed to be 20% of the energy rate, and the "escalated at 50% of CPI" line shows the scenario where operating costs are assumed to be 50% of the energy rate. The top line shows how the prices would have escalated at the fixed rate of 3%, as offered in the RFP.

In later procurements this inflation issue was addressed to a degree, with BC Hydro offering inflation that applies to a maximum 50% of the energy rate in the EPA. Given Scotia Capital suggests operating costs represent about 15-20% of the price paid, this inflation adjustment is still generous. Given only ~20% of the costs that underlie the rate are subject to inflation pressures, an offer to adjust the 50% of the rate at CPI is actually equivalent to an offer to inflate the operating costs at 2.5 times the CPI rate. Of note, if EPAs were priced at the Mid-C market rate, the inflation risk passes back to the producer and is no longer a BC Hydro concern.

Interviews confirmed that both the Ministry and BC Hydro were aware of the inflation issue revealed through the 1989 LT 5 MW call and the compromise position that more current EPAs would have a 50% CPI adjustment.

In its June 23, 2018 press release announcing the sale of a 35% interest in its NTL projects, AltaGas confirmed, "The Facilities had a total capital cost of approximately $1 billion, and are underpinned by three separate 60-year, fully indexed electricity purchase agreements with BC Hydro."

To deliver the anchor tenant that Government needed for the NTL, the Ministry ignored the lessons of history and agreed to adjust the energy rates on a 60-year EPA by full CPI, apparently without placing a cap on the CPI rate. This offered five times the inflation adjustment required to meet the exposure (given cost equivalent to only 20% of the rate is subject to inflation).

The unusually long 60-year term granted allows time for the compounding effect of inflation to create a material risk to BC Hydro. The risk can be estimated.

The three NTL EPAs commit BC Hydro to purchase 1,230 GWh of energy (to the extent AltaGas is able to deliver it; based on water conditions, at times Run-of-River projects don't deliver the full committed energy). As the EPAs are business confidential information this report has not reviewed the exact contractual terms.

Assumptions:

Delivered energy–**assume 1,230 GWh**–AltaGas intends to deliver the contract maximum.

Ratio of Firm energy: Non-Firm energy–**assume 70% Firm : 30% non-Firm**. The proportion of non-Firm energy varies broadly between IPPs, and the ratio for the three NTL projects is confidential. As Freshet happens at different times across the projects, considered as a portfolio of projects, the level of non-Firm energy on average across the portfolio is less than the level for each individual project. In its planning, BC Hydro assumes 15% non-Firm energy across the portfolio. In this example we assume 30% non-Firm energy to respect that individual projects have higher non-Firm energy than the portfolio taken as a whole.

Firm energy rate–**assume $125 /MWh**–the average Firm energy rate for the 2010 CPC

Non-Firm energy rate–**assume $100 /MWh**–80% of Firm energy rate. The average non-Firm rate for the 2010 Clean Power Call is not knows, but typically the price for non-Firm energy is lower than for Firm energy.

Term–**assume 56 years**–60-term typically runs from COD, so EPAs should have 56 years left to run.

Long-Term CPI–**Assume 2**%–BC Hydro uses a 2% CPI factor in its long-term planning

Given these assumptions, the inflation risk associated with the cost of Firm and Variable energy in the three NTL EPAs, over the remaining 56-year term of those contracts could be in the range of $7 billion. Over the first 20 years[9], $730 million of this risk could be experienced.

This estimate is sensitive to the CPI rate used. For example, if it were assumed the CPI rate over the next 56 years will be 4%, the estimated inflation risk on these three NTL contracts could grow into the range of $23 billion.

BC Hydro typically uses a long-term CPI rate of 2% in its planning. From 1980 to 1990, actual inflation averaged 5.95%. The long-term nature of the three NTL EPAs creates an exposure, which is real and potentially material.

Section 31 describes how the province changed the parameters that drive energy planning, which created the appearance that BC Hydro had an urgent need to buy 8,500 GWh. The commitment to EPAs for energy BC Hydro did not need, exposed ratepayers to an Estimated cost of approximately $16.2 billion. The Estimate does not reflect the inflation risk.

The three NTL EPAs represent 1,230 GWh of the 9,500 GWh over-buy. While the NTL EPAs carry 60-year terms and full CPI escalation, the more typical EPAs representing the 8,270 GWh balance of the over-buy had terms of 30 years, part of which has been consumed. If we apply the same assumptions used to calculate the Estimate, and assume the 50% of CPI inflation provision, an average 2% CPI over the term, the inflation risk associated with the 8,270 GWh balance of the over-buy over 20 years would be approximately $364 million. It follows that inflation on the EPAs resulting from the over-buy would carry an exposure of approximately $1 billion over the 20-year term ($370 million plus $730 million for the NTL), in addition to the $16.2 billion Estimate of the direct cost of the over-buy.

9 20 years is the estimated term used in the calculation of the Estimate

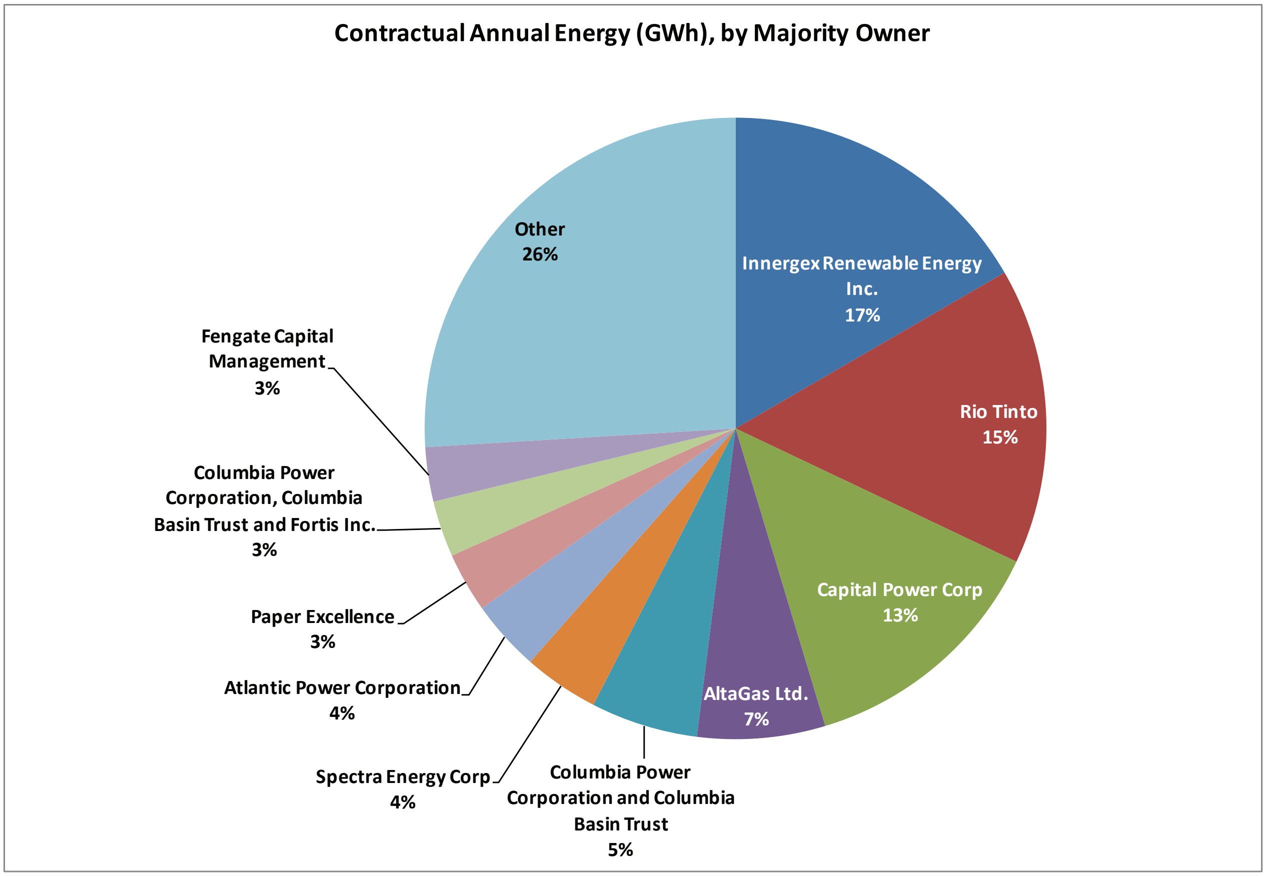
As noted, the inflation risk on the three NTL EPAs would continue for a further 36 years (after the 20-year period used to calculate the Estimate) and carry an additional inflation exposure of approximately $7 billion ($7.3 billion–$730 million) during that period.

The estimate of inflation risk introduces an additional variable, being the CPI. While the assumption of a 2% CPI (used as a planning assumption by BC Hydro) is considered reasonable, the impact calculation is sensitive to this variable. To retain the conservative nature of the $16.2 billion Estimate, the inflation risk during the next 20 years (approximately $1 billion) and the inflation risk during the last 36 years of the three NTL EPAs (approximately $7 billion) is referenced but not added to the base Estimate.

The NTL transaction does not appear to be a mistake by the Ministry negotiators. The Ministry and BC Hydro both understood the inflation issue that was identified through the 1989 LT 5 MW Call and the resolution where BC Hydro would moderate the impact with an offer of a 50% CPI escalation on more recent EPAs. No records were located that confirm why this decision was taken, but it appears to have been a conscious decision, considered necessary at the time, to obtain the customer for the NTL that the province needed.

36) Where Did the Money Go?

The simple answer is that most of money has left and continues to leave the province. The EPAs require BC Hydro consent for any proposed transfers of ownership. There has been a consolidation of ownership with control of a large portion of the portfolio moving to large energy and industrial companies, most of which are headquartered outside of B.C.



- This represents the share of the overall portfolio of EPAs, representing over 21,459 GWh
- The amounts are based on the contractual annual energy, rather than actual deliveries

Figure 15: Distribution of Contractual Annual Energy, by Majority Owner

Of those energy companies that are named in the diagram, only CPC (Columbia Power Corporation) and CBT (Columbia Basin Trust) are resident in B.C.

There are currently 120 EPAs in operation on BC Hydro's integrated system. The majority owner of 46% of these EPAs is based in BC. However, the B.C.-owned EPAs tend to be smaller projects, representing less than 20% of the contracted annual energy within the IPP portfolio.

Home Region for Majority Owner	Number of EPAs	Contracted Annual Energy (GWh)	Plant Capacity	% of Total Annual Energy	%of Total Plant Capacity
BC	55	4,067	1,236	19%	24%
Canada, Excluding BC	52	11,022	2,359	51%	45%
International	13	6,370	1,663	30%	32%
Grand Total	**120**	**21,459**	**5,258**	**100%**	**100%**

In Fiscal 2018, BC Hydro paid the existing IPP investors $1.4 billion for the energy delivered under the EPAs. Net of a small portion that remains in BC through taxes, wages and services, pro-rating on the basis of contracted energy, an estimated 81% of the $1.4 billion in payments would now flow to companies controlled from outside of BC.

37) Commercial Crown

BC Hydro is a Commercial Crown corporation, described on the province's website as follows:

> *"Commercial Crown corporations are separate legal entities that deliver goods and services on a commercial, for profit basis. They fully fund their operations and debt from revenue generated in a market environment, selling their services and products at commercial rates."*

As a Commercial Crown, BC Hydro is supposed to make commercially based decisions and to sell its service at commercial rates, and in that process to generate profits to pay for its debts and other obligations.

However, Commercial Crowns serve a "balance sheet dressing" purpose for the Province. When the Government moves commercial activities, and the associated debt, into a Crown corporation, bond rating agencies consider that debt as the responsibility of that Crown corporation. For bond rating purposes, the debt carried by the Province is thus reduced, improving the Province's balance sheet, improving the Province's bond rating and hence reducing the rate at which the Province is able to borrow.

The Province certainly has the authority to direct BC Hydro to take on non-commercial activities. However, if this happens too often, there is a risk that bond rating agencies may no longer view the debt of the Crown corporation as commercially supported and would then reverse the "balance sheet dressing", creating downward pressure on the Province's bond rating.

When Government tells BC Hydro to take on a non-commercial transaction, the cost is lost in BC Hydro's expenses. The BCUC approves rate increases based on these increased levels of expenditure, and BC Hydro allocates what should have been a provincial expenditure, to the BC Hydro ratepayers. Without transparency, provincial expenses can be "buried" in BC Hydro and passed on/embedded in the next rate increase, never to be seen again.

As BC Hydro moves forward it should consider how transparency can be added to this form of debt or expense transfer by its shareholder.

Many examples of non-commercial transactions were identified by this review, all without transparency:

- the NTL is a non-commercial project, as is its debt.

- the EPAs with IPPs (other than Anomaly Co.) are non-commercial in that the price paid for the energy under the EPA is excessive when compared to the market value of the energy. In the absence of provincial direction, BC Hydro would not have overbought energy and would not have paid above market prices for that energy.
- the creation and dissolution of BCTC was a Government decision that cost BC Hydro ratepayers an estimated $250 million.
- The immediate elimination of Burrard Thermal's energy generation was a non-commercial decision that cost ratepayers in the range of $1.2 billion.
- When individual ratepayers fall into payment arrears, service is typically terminated. There are examples where service is maintained to commercial clients that are in payment default, as terminating service could result in job losses. While this is likely required to meet Government's economic development objectives, it is still a non-commercial action and its impact should be made transparent.

In August 2018, the B.C. Auditor General reported concerns about BC Hydro arising from actions taken in Fiscal 2017 and earlier periods. She found Government did not allow unfettered oversight of BCUC but rather used cabinet orders since 2012 to override the BCUC and to set BC Hydro's rates directly. The Auditor General noted that the Government had largely ignored concerns raised by successive Auditors General on this issue. If BC Hydro were required to disclose the non-commercial aspects of all transactions, it is likely that Government would be more selective in its requests.

38) Wind and Solar

BC currently has seven IPP wind projects in operation with a combined nameplate capacity of 702 MW. Published data indicates they have an aggregate contracted annual energy of 2,010 GWh with a projected Capacity Factor of 33%. We understand in most cases, actual performance has not met original expectations and the projected Capacity Factor has not been achieved.

B.C. wind is more Intermittent than the wind in the neighbouring jurisdictions, placing BC at a material disadvantage to any party B.C. might trade with. Pacific Northwest reports a Capacity Factor for wind power around 33% and Alberta reports capacity factors for wind power in the range of 35%.

If the implementation costs were identical in all jurisdictions (which they are not), to generate a contribution to cost of $1.00, Alberta needs a power rate of $2.86, the Pacific Northwest needs a power rate of $3.03, and B.C. needs a power rate of $5.00.

Beyond the unreliability of wind, B.C. also has higher costs of construction due to mountainous terrain, requiring mobilization of installation equipment (often using helicopters), and the construction of extensive and expensive transmission lines.

B.C. currently has only one solar facility in operation so this report cannot speak in detail of it, but the same disadvantages seen for wind in B.C. exist for solar. B.C. has more cloud than Alberta or the dry areas of the Pacific Northwest or California. The aspect of the sun improves further south, placing B.C. and Alberta at a disadvantage when compared to any southern jurisdictions, and notably when compared to California.

There is little prospect of B.C. being market competitive with solar or wind. B.C. should delay such project until there is a change in that market.

B.C.'s strength is hydroelectric generation. At present B.C.'s advantage is to utilize the BC Hydro system to capture renewable oversupply in the west either for its own benefit or to sell that energy back to the market when the sun goes down or the wind stops blowing.

The difference between 'clean' and 'green' appears to be based in the certification program applied. As noted earlier, California and most jurisdictions set their green programs to both achieve clean energy (no GHG and minimized environmental disruption) but also to defend local suppliers from competition from outside the jurisdiction. BC Hydro apparently has sufficient green certified energy to meet current demand for green energy within B.C.

39) Energy Procurement and Policy Considerations

There are two categories of energy procurement where there are further policy considerations: Biomass Generation and Impact Benefit Agreements.

Biomass Generation

Biomass generation provides reliable, Firm, non-Intermittent energy that is dispatchable. On the integrated system, BC Hydro has biomass EPAs with one standalone facility, and 18 cogeneration facilities associated with either a pulp mill or sawmill. These projects support the forest sector and communities, as well as use wood waste that would otherwise need to be disposed. These benefits would be nullified if the price paid for energy moves immediately to market upon renewal and the projects were to fail as a result.

The Ministry is in discussions with these EPA holders and their industry association. There will a need for some pragmatism in the renewal of these IPP that will likely feature a renewal rate above Mid-C but less than the first term rate. The renewal needs a firm understanding that no rate above Mid-C will persist beyond the renewal term. The portion of the new rate in excess of Mid-C should be subject to the transparency recommendations that follow in this report.

Impact Benefit Agreements

The Mandate Letter from the Minister to BC Hydro emphasizes that Government is fully adopting and implementing the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) and the Calls to Action of the Truth and Reconciliation Commission (TRC). The Mandate Letter asks BC Hydro to ensure to incorporate the UNDRIP and TRC, given the mandate and context of the organization.

BC Hydro has a commitment to connect with and build lasting relationships with First Nations and Indigenous communities in B.C. BC Hydro's statement of Indigenous Principles commits to seeking opportunities for meaningful benefit with First Nation communities as BC Hydro refurbishes existing facilities and assets, builds new infrastructure or undertakes work. In some cases, BC Hydro enters into an Impact Benefit Agreement, which is an agreement between BC Hydro and a First Nation to address adverse impacts arising from the construction of BC Hydro's projects that cannot be avoided, mitigated or otherwise accommodated. If procurement of energy factors into any of these agreements, it is the recommendation of this report that both Government and BC Hydro provide transparent information about the rationale for that procurement.

40) EPA Renewals

BC Hydro has one opportunity to correct its financial situation, and that opportunity occurs at the point EPAs renew. Early projects are now coming up for renewal, and those renewals are subject to BCUC approval. BC Hydro is negotiating renewals with IPPs, taking into consideration issues including the IPP's cost of service, including the rate of return available to the investor.

The IPPs are represented by an effective industry association. Any renewal strategy that features bilateral negotiations of prices designed to reflect cost of service and future rate of return will be subject to upward pressure and ultimately fail to fully correct the cost issues BC Hydro is facing.

It is recommended that BC Hydro settle on one commercial proposal it is prepared to present to all EPA investors. While the IPP program has produced facilities that BC Hydro may not need today, it will likely need this energy to meet future demand. BC Hydro should renew every EPA if it can ensure the future energy price aligns with market value of the energy, Mid-C, and if it can rely on Powerex to trade excess power in the interim, at that same Mid-C rate.

When considering the basis upon which IPPs should be renewed by BC Hydro, one should consider four points:

1. The IPP industry has benefitted immensely from the EPAs, including the energy rates offered and the $17 billion Estimate of the impact resulting from the policy direction to buy 8,500 GWh in Firm power BC Hydro never needed,
2. Currently, 81% of the energy delivered through the EPAs is owned by energy and industrial companies, not headquartered in B.C.
3. The assets created through IPP purchases are located in BC and have only two potential customers for the energy they generate; BC Hydro or the export market, assuming BC Hydro is willing to firm, shape, and transmit their power.
4. Energy has only one price and that is the price it can be bought or sold at in the market. In the case of BC Hydro, the market value of all energy is the Mid-C rate.

The original vision was to create export capacity, with BC Hydro supporting by firming, shaping, and transmitting the energy to the Mid-C hub, where it could be sold profitably by the developer. The program collapsed back to the comfort of a BC Hydro covenant and the take-or-pay EPA with its transfer of market and inflation risks to BC Hydro, when it became apparent that the energy crisis was actually based on fraud and the trading market collapsed.

The analysis in this report indicates that while Anomaly Co. is likely the least profitable IPP, it has still proven to be a solid investment for the original developer. The simple fact is that Anomaly Co., has likely repaid its construction cost base, funded sustaining capital, been sold apparently at a material capital gain, and continues to generate contributions beyond its operating costs, all with revenues based on the Mid-C rate. If Anomaly Co. remains profitable, there is reason to expect other run-of-river projects of similar size or larger could be viable upon renewal on the same basis.

In the specific case of Anomaly Co., the original developer has sold the project to an investor. The investor who bought Anomaly Co. was betting that BC Hydro's largesse would continue into the future. The investor cashed out the original developer, creating an investment cost base, which is not the same as the construction cost base of the original developer.

BC Hydro has no obligation to this investor and certainly no obligation to pay more than the power is worth to ensure the future viability of the investment. The current renewal strategy (that has been used on the first set of renewals) considers an IPP's cost of service, including rate of return. This approach will not deliver energy to ratepayers at its real market value.

BC Hydro is a Commercial Crown corporation and should do nothing more or less than act in a commercial manner. Any offer of a renewal rate that is negotiated based on the IPPs cost of service and a rate of return, rather than the market value of the energy produced, is a non-commercial act; it is somewhat equivalent to a guarantee of future profit for the out of province investor who now owns the project. BC Hydro should establish one reasonable commercial proposition, define that proposition in appropriate detail and present it as the only commercial offer BC Hydro will make to investors holding a maturing IPP generating Intermittent energy.

The reasonable commercial proposal should acknowledge that if any Intermittent generation facility cannot make a profit being paid the full market value of the energy it produces, it is by definition not viable and should cease operations.

The commercial proposal (Commercial Proposal) for the renewal of IPPs generating Intermittent energy should be along the following lines:

> The IPP energy is in the BC Hydro system, so transmission costs within BC are moot. BC Hydro should offer to buy the Firm energy at the appropriate Mid-C price for Firm energy (can consider a term price providing the term is no longer than the term of the EPA), and the Intermittent and non-Firm energy at the Mid-C spot price.
>
> Term of the EPA should be in the range of 5-10 years. All of this would need to consider how the resources would fit into BC Hydro long-term Resource Plan.

There is no need for 30 to 60 year terms as the payback of construction costs is no longer an issue. Any financing the investor has is not related to the cost of construction–that was paid long ago through the excess prices BC Hydro paid in the original EPA. Existing financing secured by the IPP project is an issue between the investor and its bank, and shouldn't be of concern to BC Hydro.

If this Commercial Proposal is not acceptable to the investor or its bank, the investor already has the option to transmit the IPP energy to the Mid-C hub through the Open Access Transmission Tariff, with the cost of transmission and any ancillary services to be borne by the investor. The investor is then free to trade the energy on the open market as it sees fit.

It is likely that the IPPs and industry association would oppose this proposal, notwithstanding it is commercially reasonable: BC Hydro is offering to buy the energy at its full market value. If the investor believes the energy is worth a higher price, BC Hydro is offering to deliver the energy to the market, at which point the investor is free to negotiate a superior rate.

If the Government and BC Hydro endure the opposition, one of two things will happen; either the IPP will meet its costs and generate a contribution under the Commercial Proposal, or it will not. If it can meet its operating costs and generate a contribution, the investor will accept the Commercial Proposal and the project will continue. Ultimately, the investor may suffer a loss and the project may move to a new investor with a lower purchase cost base, but the IPP will continue to run generating energy at its Mid-C market value.

If an IPP cannot meet its operating costs, the project will cease operations, which is the proper fate for any enterprise that is not commercially viable. When the project can't meet its costs, operations will cease and the facility will go into realization. The nature of the realization process will depend on the security interests held. Suffice to say, it will take time, the facility will deteriorate, and many lawyers will be paid.

When operations cease, site reclamation issues will arise and typically flow to the last owner. It appears that site remediation or reclamation bonds were not required when these EPAs were finalized. While a full legal review on reclamation is beyond the scope of this review, typically the reclamation liability will impact asset sales and give the province a role and some say in the liquidation.

The Commercial Proposal should accommodate security realization. If the realization results in a proposed sale to a third-party intent on operating the facility, BC Hydro should offer the Commercial Proposal to that party. If the realization doesn't lead to a sale, BC Hydro should offer to buy the assets and undertakings so it can control the remediation and ensure it is completed in a safe and sensitive manner. At this point, the investor has confirmed no commercial buyer is available and the facility has no commercial value. Any offer the Province/BC Hydro makes stops the accruing legal costs and is "found money." The Commercial Proposal should include a set "offer amount", likely something nominal, in the range of 5% of original cost.

To be clear, this is not a low-ball offer; the asset has no commercial value and any cash offer is generous. Again, this must be a standard offer and not subject to negotiation. If the offer is not accepted, the Province should enforce its position on site remediation, to the extent it can.

This sets out the primary terms of a Commercial Proposal and a liquidation scenario, where the investor doesn't believe the Commercial Proposal is viable. BC Hydro needs to consider how often it will find itself in the liquidation scenario.

The 2008 report published by Scotia Capital, suggests operating costs for a larger Run-of-River project would fall in a range of $8-$16/MWh in 2008 or $12-$20/MWh today. This Scotia Capital cost analysis suggests most if not all run-of-river projects would cover operating costs and generate a contribution at a blend of Mid-C Firm and Mid-C spot rates. Based on this, BC Hydro can likely expect the liquidation scenario to be a relatively rare event.

The adoption of a proposal similar to the Commercial Proposal, will require a detailed legal review of each impacted EPA to confirm there are no conditions for renewal of which staff interviewed for this report are unaware.

Renewal of the EPAs associated with IPPs generating Firm energy is a separate case. The price of energy from these projects can be referenced to the value of energy in the market, but must also reflect the cost of fuel consumed in the production of the energy (an ongoing cost not incurred with Wind, Solar, and Run-of-River).

Conclusions and Recommendations

41) Conclusions

The chronology and the analysis set out in this report describes how the Province of British Columbia set a direction towards energy self-sufficiency and green/clean power generation and then enacted that direction through the 2002 Energy Plan, the 2007 Energy Plan–Vision for Clean Energy Leadership, and the 2010 *Clean Energy Act*. Government provided clear direction to BC Hydro that resulted in BC Hydro not increasing its own generating capacity and not importing power to meet demand. Government then adjusted the parameters that drive the energy planning process at BC Hydro, to create the appearance of an urgent need for more Firm energy.

This need for Firm energy forced BC Hydro to elicit IPP proposals. BC Hydro responded to Government's direction and went to market with requests for large volumes of energy and signalling on the price it was willing to pay. Together these two factors drove EPA prices higher.

Both the Ministry and BC Hydro tried to alert Government that a material shift in the energy market was occurring in 2009. Government responded with the 2010 *Clean Energy Act*, which accelerated the program.

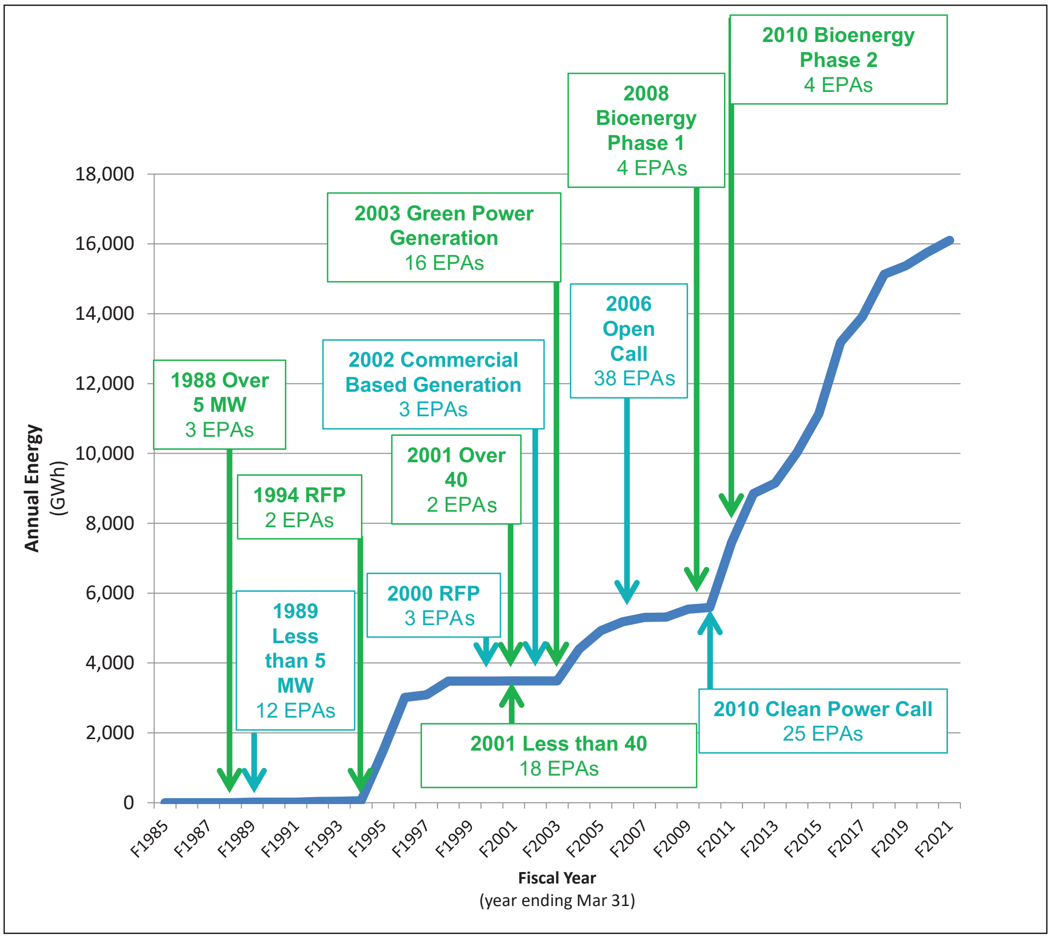


Figure 16: History of BC Hydro Procurement Processes and Related Contractual Energy (GWh/y)

The Government started to relax its direction in 2013, but by then the damage had been done. At the direction of Government, BC Hydro had committed to overbuying IPP energy.

This report draws three conclusions with respect to IPPs:

- BC Hydro bought too much energy and energy with the wrong profile,
- BC Hydro paid too much for the energy it bought, and
- BC Hydro undertook these actions at the direction of Government.

Government directed BC Hydro to purchase 8,500 GWh/year of Firm energy BC Hydro did not need. This direction of BC Hydro's actions is manifest in the Response EPAs through which BC Hydro managed to acquire 9,500 GWh of blended energy, which is equivalent to 8,075 GWh of Firm energy. The Response EPAs cost ratepayers an Estimated $16.2 billion over 20 years, the estimated period during which BC Hydro will likely not need the energy Government told it to buy. The annual impact of this surplus energy to BC Hydro ratepayers is estimated as $808 million per year or ~$200 per year per residential ratepayer, which is equivalent to $4,000 per residential ratepayer over 20 years. The $16.2 billion Estimate is believed to be conservative.

The Estimate is associated with the cost of buying energy from the Response EPAs, during the period BC Hydro likely will not need the energy. Even if load grows to the point BC Hydro needs this energy, it will be faced with the issue that it is paying too much for it.

As demonstrated in Section 31, over the balance of the term of the Response EPAs, BC Hydro will lose an additional ~$6.8 billion selling energy to ratepayers for rates less than BC Hydro is buying it from IPPs.

The EPAs offer various forms of inflation protection to the contractors; in some cases, full CPI protection. Given the contract terms of the EPAs and the quantity of energy covered, the estimated impact of the inflation risk (assuming a 2% CPI that is often used by BC Hydro for its planning) could potentially add another $1 billion to the cost Estimate over the next 20 years. The three NTL EPAs extend for 36 years beyond the 20-year period of the Estimate and carry an incremental inflation risk over this extended period in the range of $7 billion.

To facilitate the approval of IPPs contracts, Government eliminated the regulatory oversight designed to protect ratepayers. Government passed legislation to "modernize" the BCUC, which removed BCUC oversight from BC Hydro capital projects and IPP energy purchases, while leaving the BCUC with the responsibility of approving the rate increases needed to pay for the projects the Government directed.

Government direction has also led to a situation where BC Hydro now has an imbalance in its energy mix, with disproportionate amounts of non-Dispatchable, Intermittent power from IPPs on take or pay contracts. Section 29 highlights that BC Hydro can no longer shape and firm effectively. These IPPs now dominate the management of BC Hydro's Dispatchable power sources and have largely eliminated the trading advantage BC Hydro had held previously. This introduces a significant inefficiency into BC Hydro's operation, the cost of which is difficult to quantify.

There is a need for more transparency respecting non-commercial transactions BC Hydro is directed by Government to undertake. These projects have now aggregated to the point that the financial stability of BC Hydro has been impacted.

Wind and solar power IPPs have been implemented in B.C. Both experiences support the available science: B.C. has poor solar and wind conditions and is at a commercial disadvantage compared to the neighbouring jurisdictions. It is unlikely that wind and solar generation can be done in a competitive manner in B.C., at least until there is a material change in the market environment and BC Hydro has the additional capacity (e.g. as will be provided by Site C) it needs to Firm the incremental Intermittent power that would result.

Lastly, there are projects, like biomass energy projects, with broader benefits that continue to be important to the Province. When these agreements reach maturity and are considered for renewal provincial program benefits should be a consideration.

The only available solution to the financial impacts described comes when the EPAs associated with IPP projects generating Intermittent energy mature and BC Hydro has an opportunity to renew them. Energy has only one value and that is the market rate it can be traded at, the Mid-C rate. The financial issues described in this report will continue if

BC Hydro adopts an EPA renewal strategy for IPP projects generating Intermittent energy at any price other than the existing Mid-C market rate.

42) Recommendations

A. EPA Renewals

BC Hydro should offer the Commercial Proposal (or some variation thereto), as the only offer it will make to IPP investors. The Commercial Proposal should feature an offer to either:

a. buy all energy at the appropriate Mid-C market rate, or

b. have the investor trade its energy directly in the market, which is currently an option. Cost of shaping, firming and line losses are to the account of the investor.

If the investor believes the project is not commercially viable, BC Hydro should offer to buy the assets for a small fraction of their original cost.

If the project is not commercially viable and the asset sale offer is not acceptable to the investor, BC Hydro should allow the project to fail and the province should enforce remediation obligations.

B. Residual Transactions

Section 43 of this report speaks to the renewal of Biomass IPPs. To ensure the program benefits being generated from these investments are realized, Government could offer direction to BC Hydro to pursue these transactions if they cannot be justified on a commercial basis but are subject to considerations that are a matter of Government policy.

BC Hydro should follow the direction of the shareholder to continue these projects if that is the direction provided. In this case, BC Hydro should reflect the non-commercial nature of the transactions in a transparent way.

C. BCUC and Transparency

The 2010 *Clean Energy Act* introduced changes to BCUC that were euphemistically described as the 'modernization' of BCUC. All changes made through the *Clean Energy Act* should be reversed and BCUC's full oversight role should be re-established.

The establishment of the historic role will need to accommodate the regularization of the residual transactions described in Section 43, with a short-term exemption from BCUC oversight for those matters.

Government is the sole shareholder of BC Hydro and will provide direction to the Crown corporation. The following guidelines will enable transparency on energy procurement:

- If BC Hydro is told to buy energy at rates above Mid-C, the differential (non-commercial) value of the energy should be recorded separately, identifying "Government direction" as the rationale for the purchase amount.
- BC Hydro must disclose in BCUC submissions, all instances where energy purchases are not at Mid-C and all instances where the business case supporting procurement of energy is not, in its opinion, a commercial proposition. In such cases, the value of the non-commercial aspects of the project would be recorded in a separate category that

identifies the source of that amount as "Government direction." This takes a step further the current process whereby BC Hydro provides information on costs, including its opportunity cost over the term of the EPA, for BCUC review.

D. Standing Offer Program

BC Hydro has purchased too much Intermittent IPP energy and should not have a procurement process that remains open. The SOP is currently on hold, but ideally, should be terminated.

As the SOP is prescribed in legislation, BC Hydro has no ability to permanently impact the future of the SOP. If the SOP is to be terminated, Government would need to make a legislative change to terminate the program.

E. Self-Sufficiency Mandate

The self-sufficiency mandate should be eliminated. Energy planning should be permitted to rely on a reasonable level of Powerex trading and not reflect the need for "insurance" energy.

F. Green/Clean Power

BC Hydro currently holds sufficient green certified energy for demands within B.C. and to meet the limited trading options with California.

Despite the fact that BC Hydro and Powerex have been able to recover some of the sunk costs associated with existing "Green Certified" IPP purchases (typically wind plants) by trading with the California market, the experience is that B.C. IPP's have not been competitive for export on a standalone basis. While BC Hydro should insist on retaining the rights to apply for Green Certification for any energy that it procures, any business case for the build of new IPP's based on green certification in export markets should be carefully reviewed.

BC Hydro should continue its focus on the generation of clean energy with no carbon or GHG impacts, in support of the Province's climate targets and policies.

Appendix A: Select Sources Consulted

- BC Laws. *Clean Energy Act*. (Act is current to November 21, 2018)
- British Columbia Utilities Commission. F2017 to F2019 Revenue Requirements Application Decision and Order G-47-18 (March 1, 2018).
- British Columbia Utilities Commission. Inquiry Respecting Site C Preliminary Report (September 20, 2017). BC Hydro. Briefing Note: Columbia Power Corporations Waneta Expansion Project (November 30, 2006).
- BC Hydro. Contracted Generator Baseline Guidelines (November 2015).
- BC Hydro. Energy Procurement Review: Summary of Merrimack's Recommendations and BC Hydro's Response (September 23, 2011).
- BC Hydro. Estimates Note: Independent Power Producers (April 27, 2018).
- BC Hydro. Estimates Note: Standing Offer and Micro Standing Offer Programs (26 April 2018).
- BC Hydro. CEC Information Request No. 2.135.3, Fiscal 2017–Fiscal 2019 Revenue Requirements Application, Historical and Actual Forecasts of Total Gross Requirements from BC Hydro 2006 Integrated Electricity Plan and LTAP (December 16, 2016).
- BC Hydro. Independent Power Projects (website).
- BC Hydro. Independent Power Producers (IPPs) currently supplying power to BC Hydro (As of April 1, 2018).
- BC Hydro. Independent Power Producers (IPPs) with projects currently in development (As of April 1, 2018).
- BC Hydro. IPP Supply Map (As of April 1, 2018).
- BC Hydro. Overview of BC Hydro's Energy Procurement Practices (November 2013).
- BC Hydro. Transmission Service and General Service Self-Generation in the BC Hydro Service Area (date not listed).
- CIBC Earnings Update. AltaGas Ltd.: B.C. Hydro Sale Improves Funding Picture; Increasing Target (June 13, 2018).
- Merrimack Energy Group, Inc. Final Report on BC Hydro's Energy Procurement Practices (February 2011).
- Province of British Columbia. Backgrounder on the *Clean Energy Act*: Clean and Renewable Electricity Development (April 28, 2010).
- Province of British Columbia. The BC Energy Plan: A Vision for Clean Energy Leadership (February 27, 2007)
- Province of British Columbia. Energy for our Future: A Plan for BC (November 2002).
- Scotia Capital–Alternative and Renewable Energy, August 2008

Appendix B: BC Hydro Heritage Assets

Heritage Asset	Dependable Capacity (MW) for F2020, based on F17-F19 RRA LRB	Comments
Aberfeldie	5	
Alouette	0	Not currently generating electricity
Ash River	27	
Bridge River	416	
Buntzen/Coquitlam	60	
Burrard Thermal	n/a	No longer used for power generation
Cheakamus	158	
Clowhom	30	
Duncan	n/a	Has no power generation facility
Elko	0	Not currently generating electricity
Falls River	5	
Fort Nelson	n/a	Excluded because facility is not connected to integrated system
GMS	2,770	
Hugh Keenleyside Dam (Arrow Reservoir)	n/a	Generation facility belongs to Columbia Power
John Hart	127	
Jordan	167	
Kootenay Canal	570	
La Joie	22	
Ladore	47	
Mica (Units 1 to 6)	2,580	
Peace Canyon	660	
Prince Rupert	46	
Puntledge	18	
Revelstoke (Units 1 to 5)	2,440	Unit 6 would add another 488 MW of dependable capacity
Ruskin	114	
Site C	n/a	Not in service in F2020; once in service, Site C would add 1,145 MW of dependable capacity
Seton	42	
Seven Mile	580	
Shuswap	3	
Spillimacheen	4	
Stave Falls	90	
Strathcona	60	
Wahleach	63	
Walter Hardman	8	
Waneta Transaction	250	Represents 1/3 of total Waneta generation as based on 2010 Transaction
Whatshan	54	
Integrated System Total for F2020, based on F17-F19 RRA LRB	**11,416**	

Appendix C: Mid-C Data

Trade date	Delivery start date	Delivery end date	High price $/MWh	Low price $/MWh	Wtd avg price $/MWh	Change	Daily volume MWh	Number of trades	Number of counterparties
10/2/2017	10/3/2017	10/3/2017	24.25	23.5	23.99	-0.98	18,000	42	14
10/3/2017	10/4/2017	10/4/2017	26.5	25	26.01	2.02	17,200	43	15
10/4/2017	10/5/2017	10/5/2017	28	25	26.34	0.33	29,200	68	17
10/5/2017	10/6/2017	10/7/2017	23	22	22.45	-3.89	43,200	51	18
10/6/2017	10/9/2017	10/9/2017	30	27.25	28.6	6.15	31,600	77	19
10/9/2017	10/10/2017	10/10/2017	28.5	25	26.59	-2.01	23,200	54	14
10/10/2017	10/11/2017	10/11/2017	27	25	26	-0.59	22,400	55	19
10/11/2017	10/12/2017	10/12/2017	27	26	26.65	0.65	20,400	49	14
10/12/2017	10/13/2017	10/14/2017	26	24.5	25.09	-1.56	36,000	45	15
10/13/2017	10/16/2017	10/16/2017	29	27.75	28.63	3.54	28,400	70	18
10/16/2017	10/17/2017	10/17/2017	25	24.25	24.74	-3.89	19,600	49	17
10/17/2017	10/18/2017	10/18/2017	31.5	29	30.05	5.31	24,400	55	16
10/18/2017	10/19/2017	10/19/2017	27.5	26.5	27.31	-2.74	27,200	64	19
10/19/2017	10/20/2017	10/21/2017	30	25	28.65	1.34	43,200	51	14
10/20/2017	10/23/2017	10/23/2017	38	32	36.46	7.81	14,400	29	12
10/23/2017	10/24/2017	10/24/2017	35	27	31.03	-5.43	23,200	57	17
10/24/2017	10/25/2017	10/25/2017	27	25	25.61	-5.42	8,800	19	11
10/25/2017	10/26/2017	10/26/2017	27	23	25.64	0.03	10,800	26	14
10/26/2017	10/27/2017	10/28/2017	26	24.5	25.12	-0.52	26,400	33	17
10/27/2017	10/30/2017	10/30/2017	25	23.75	24.33	-0.79	30,000	67	15
10/30/2017	10/31/2017	10/31/2017	25.5	23.5	24.23	-0.1	14,000	34	14
10/31/2017	11/1/2017	11/1/2017	24.75	22.75	23.09	-1.14	24,800	47	14
11/1/2017	11/2/2017	11/2/2017	26	25	25.49	2.4	22,000	55	17
11/2/2017	11/3/2017	11/4/2017	29.75	28	28.9	3.41	49,600	62	14
11/3/2017	11/6/2017	11/6/2017	47	36	42.2	13.3	20,800	52	17
11/6/2017	11/7/2017	11/7/2017	37.5	30	32.7	-9.5	18,000	45	16
11/7/2017	11/8/2017	11/9/2017	27	23	25.05	-7.65	62,400	77	15
11/8/2017	11/10/2017	11/11/2017	26.25	24	24.99	-0.06	36,000	44	15
11/9/2017	11/13/2017	11/13/2017	23.25	21	22.04	-2.95	24,400	59	20
11/13/2017	11/14/2017	11/14/2017	24.25	23.75	24.09	2.05	16,400	41	14
11/14/2017	11/15/2017	11/15/2017	25.45	24.5	24.91	0.82	21,200	52	16
11/15/2017	11/16/2017	11/16/2017	25.75	23.75	25.18	0.27	17,600	44	15
11/16/2017	11/17/2017	11/18/2017	25	24	24.43	-0.75	30,400	37	13
11/17/2017	11/20/2017	11/20/2017	27.25	25.25	26.27	1.84	19,600	49	16
11/20/2017	11/21/2017	11/22/2017	26.75	25.25	26.38	0.11	44,000	55	16
11/21/2017	11/24/2017	11/24/2017	25.5	23.25	24.14	-2.24	25,600	64	16
11/22/2017	11/25/2017	11/27/2017	25	22	24.57	0.43	36,800	46	15
11/27/2017	11/28/2017	11/28/2017	25	22.75	23.74	-0.83	19,200	48	17
11/28/2017	11/29/2017	11/29/2017	25	23.75	24.27	0.53	23,200	56	19
11/29/2017	11/30/2017	11/30/2017	25.25	24	24.75	0.48	23,600	58	17
11/30/2017	12/1/2017	12/2/2017	24.5	22.75	23.71	-1.04	64,000	78	20
12/1/2017	12/4/2017	12/4/2017	25.25	23.5	24.47	0.76	23,600	59	17
12/4/2017	12/5/2017	12/5/2017	28.25	27	27.87	3.4	29,200	69	18
12/5/2017	12/6/2017	12/6/2017	29	28.25	28.71	0.84	30,400	66	18
12/6/2017	12/7/2017	12/7/2017	26.5	25.5	25.89	-2.82	21,200	52	17
12/7/2017	12/8/2017	12/9/2017	26.75	24.75	25.55	-0.34	43,200	53	17
12/8/2017	12/11/2017	12/11/2017	26.75	26	26.33	0.78	26,800	65	13
12/11/2017	12/12/2017	12/12/2017	35	30	31.83	5.5	31,200	78	18
12/12/2017	12/13/2017	12/13/2017	35.25	33	34.54	2.71	22,800	56	16

Trade date	Delivery start date	Delivery end date	High price $/MWh	Low price $/MWh	Wtd avg price $/MWh	Change	Daily volume MWh	Number of trades	Number of counterparties
12/13/2017	12/14/2017	12/14/2017	33.25	30	31.55	-2.99	25,600	61	15
12/14/2017	12/15/2017	12/16/2017	26.75	25.75	26.17	-5.38	41,600	50	14
12/15/2017	12/18/2017	12/18/2017	25.75	23.5	24.5	-1.67	22,000	55	15
12/18/2017	12/19/2017	12/19/2017	25.5	24.5	25.29	0.79	20,800	46	14
12/19/2017	12/20/2017	12/20/2017	37.75	34	35.19	9.9	30,400	70	14
12/20/2017	12/21/2017	12/22/2017	38	29	33.46	-1.73	28,000	35	11
12/21/2017	12/23/2017	12/23/2017	29	24.75	25.83	-7.63	22,000	53	15
12/22/2017	12/26/2017	12/26/2017	30.25	28.5	29.16	3.33	17,200	43	16
12/26/2017	12/27/2017	12/27/2017	27.5	26.75	27.08	-2.08	24,800	57	16
12/27/2017	12/28/2017	12/29/2017	25.5	23	24.08	-3	43,200	54	16
12/28/2017	12/30/2017	12/30/2017	24	21	21.74	-2.34	31,200	76	15
12/29/2017	1/2/2018	1/2/2018	32	29	30.92	9.18	27,600	66	15
1/3/2018	1/4/2018	1/4/2018	35.75	28.75	31.15	-3.06	24,000	59	19
1/4/2018	1/5/2018	1/6/2018	23.5	22	23.13	-8.02	54,400	65	15
1/5/2018	1/8/2018	1/8/2018	25.15	23.75	24.36	1.23	34,000	85	19
1/9/2018	1/10/2018	1/10/2018	21	19	20.22	-0.05	28,400	67	16
1/10/2018	1/11/2018	1/12/2018	21	19.75	20.51	0.29	72,800	84	22
1/11/2018	1/13/2018	1/13/2018	23	20	21.25	0.74	39,600	96	17
1/12/2018	1/15/2018	1/16/2018	25	23	24.15	2.9	54,400	66	17
1/16/2018	1/17/2018	1/17/2018	23	21.5	22.25	-1.9	32,400	74	16
1/17/2018	1/18/2018	1/18/2018	21	20	20.66	-1.59	45,200	99	18
1/18/2018	1/19/2018	1/20/2018	20.5	19.75	20.26	-0.4	68,000	83	15
1/19/2018	1/22/2018	1/22/2018	23	21.5	21.74	1.48	34,400	86	17
1/22/2018	1/23/2018	1/23/2018	24.75	23	23.65	1.91	36,000	89	18
1/23/2018	1/24/2018	1/24/2018	22	21.5	21.84	-1.81	25,600	64	17
1/24/2018	1/25/2018	1/25/2018	21.75	20.75	21.36	-0.48	31,200	70	17
1/25/2018	1/26/2018	1/27/2018	20	18.75	19.39	-1.97	41,600	51	17
1/26/2018	1/29/2018	1/29/2018	21.25	19.5	20.18	0.79	27,200	59	16
1/29/2018	1/30/2018	1/30/2018	17	15	16	-4.18	40,000	88	17
1/30/2018	1/31/2018	1/31/2018	22	19.5	20.38	4.38	38,800	91	19
1/31/2018	2/1/2018	2/1/2018	21.5	19.75	20.23	-0.15	36,800	81	19
2/1/2018	2/2/2018	2/3/2018	10	5.5	8.03	-12.2	59,200	73	19
2/2/2018	2/5/2018	2/5/2018	13.5	9	12.27	4.24	28,800	69	17
2/5/2018	2/6/2018	2/6/2018	17	12.5	15.27	3	41,600	100	22
2/6/2018	2/7/2018	2/7/2018	16.25	12.25	13.52	-1.75	38,000	83	20
2/7/2018	2/8/2018	2/8/2018	13	9	10.46	-3.06	47,200	109	19
2/8/2018	2/9/2018	2/10/2018	19	16	17.46	7	91,200	110	20
2/9/2018	2/12/2018	2/12/2018	23	20.25	20.95	3.49	35,600	77	13
2/12/2018	2/13/2018	2/13/2018	25	22.75	23.67	2.72	35,600	83	17
2/13/2018	2/14/2018	2/14/2018	24	16	19.81	-3.86	30,000	69	15
2/14/2018	2/15/2018	2/16/2018	20.5	19.75	20.1	0.29	53,600	60	16
2/15/2018	2/17/2018	2/17/2018	14	9	10.6	-9.5	41,200	100	20
2/16/2018	2/19/2018	2/20/2018	40	33	35.35	24.75	76,800	86	18
2/20/2018	2/21/2018	2/21/2018	50	36	37.96	2.61	36,800	86	19
2/21/2018	2/22/2018	2/22/2018	52	46	49.34	11.38	43,200	104	18
2/22/2018	2/23/2018	2/24/2018	24	21.25	22.59	-26.75	48,000	60	16
2/23/2018	2/26/2018	2/26/2018	26	24	25.21	2.62	30,000	69	15
2/26/2018	2/27/2018	2/27/2018	23	21	22.21	-3	28,800	62	17
2/27/2018	2/28/2018	2/28/2018	26.25	25	25.6	3.39	38,400	95	16
2/28/2018	3/1/2018	3/1/2018	25.5	24	24.74	-0.86	40,400	95	18

Trade date	Delivery start date	Delivery end date	High price $/MWh	Low price $/MWh	Wtd avg price $/MWh	Change	Daily volume MWh	Number of trades	Number of counterparties
3/1/2018	3/2/2018	3/3/2018	22.25	20	20.94	-3.8	62,400	71	20
3/2/2018	3/5/2018	3/5/2018	31	24.5	26.9	5.96	35,600	82	17
3/5/2018	3/6/2018	3/6/2018	33	30	31.06	4.16	35,600	83	12
3/6/2018	3/7/2018	3/7/2018	32.5	30.25	31.24	0.18	37,600	90	15
3/7/2018	3/8/2018	3/8/2018	22	20	20.77	-10.47	19,200	48	14
3/8/2018	3/9/2018	3/10/2018	19.25	15.5	17.92	-2.85	33,600	42	15
3/9/2018	3/12/2018	3/12/2018	21.5	18	20.86	2.94	32,400	78	18
3/12/2018	3/13/2018	3/13/2018	21	19.75	20.11	-0.75	25,200	56	16
3/13/2018	3/14/2018	3/14/2018	19	18	18.2	-1.91	28,400	67	19
3/14/2018	3/15/2018	3/15/2018	23.75	21.5	23.02	4.82	32,000	69	16
3/15/2018	3/16/2018	3/17/2018	21.5	19	20.73	-2.29	40,800	46	18
3/16/2018	3/19/2018	3/19/2018	23	21.5	22.57	1.84	29,200	65	17
3/19/2018	3/20/2018	3/20/2018	22.75	19	22.29	-0.28	36,000	82	17
3/20/2018	3/21/2018	3/21/2018	21	20	20.22	-2.07	20,400	41	15
3/21/2018	3/22/2018	3/22/2018	18.5	16.5	17.01	-3.21	28,000	68	16
3/22/2018	3/23/2018	3/24/2018	19.5	18.75	19.09	2.08	56,000	63	17
3/23/2018	3/26/2018	3/26/2018	19.85	18.75	19.14	0.05	42,800	90	19
3/26/2018	3/27/2018	3/27/2018	16	13	14.56	-4.58	29,200	66	19
3/27/2018	3/28/2018	3/29/2018	17.5	14.5	15.97	1.41	72,800	88	22
3/28/2018	3/30/2018	3/31/2018	16.75	14	16.14	0.17	58,400	73	17
3/29/2018	4/2/2018	4/2/2018	17.25	14	15.48	-0.66	39,600	70	18
4/2/2018	4/3/2018	4/3/2018	23	18.35	20.75	5.27	29,600	72	17
4/3/2018	4/4/2018	4/4/2018	25	23	24.14	3.39	30,000	66	19
4/4/2018	4/5/2018	4/5/2018	25	24.25	24.77	0.63	34,400	69	17
4/5/2018	4/6/2018	4/7/2018	15	13.75	14.37	-10.4	23,200	29	11
4/6/2018	4/9/2018	4/9/2018	24.5	21	23.03	8.66	33,200	70	16
4/9/2018	4/10/2018	4/10/2018	18	15	16.67	-6.36	44,400	93	19
4/10/2018	4/11/2018	4/11/2018	23.25	21	22.32	5.65	45,200	103	19
4/11/2018	4/12/2018	4/12/2018	16.5	13.5	14.99	-7.33	40,400	97	19
4/12/2018	4/13/2018	4/14/2018	18	16	17.03	2.04	71,200	79	19
4/13/2018	4/16/2018	4/16/2018	18	16	17.15	0.12	40,800	93	21
4/16/2018	4/17/2018	4/17/2018	16	13.5	14.43	-2.72	30,800	76	20
4/17/2018	4/18/2018	4/18/2018	26.5	24	25.24	10.81	44,400	104	16
4/18/2018	4/19/2018	4/19/2018	23.5	22	22.78	-2.46	34,400	69	16
4/19/2018	4/20/2018	4/21/2018	11.25	8	10.44	-12.34	73,600	83	19
4/20/2018	4/23/2018	4/23/2018	22	18	21.09	10.65	49,200	121	17
4/23/2018	4/24/2018	4/24/2018	23.5	20	20.95	-0.14	44,400	110	18
4/24/2018	4/25/2018	4/25/2018	25	22	23.56	2.61	37,200	79	14
4/25/2018	4/26/2018	4/26/2018	24	19.25	21.88	-1.68	41,200	92	21
4/26/2018	4/27/2018	4/28/2018	7.5	1	4.5	-17.38	57,600	69	18
4/27/2018	4/30/2018	4/30/2018	17	9	14.23	9.73	32,000	77	19
4/30/2018	5/1/2018	5/1/2018	19.5	16.25	17.47	3.24	33,200	77	21
5/1/2018	5/2/2018	5/2/2018	24	20	22.29	4.82	38,000	94	18
5/2/2018	5/3/2018	5/3/2018	17.5	16	16.94	-5.35	24,800	61	18
5/3/2018	5/4/2018	5/5/2018	14	12	12.72	-4.22	34,400	43	9
5/4/2018	5/7/2018	5/7/2018	24	15	18.28	5.56	31,600	73	14
5/7/2018	5/8/2018	5/8/2018	20	15	17.46	-0.82	44,400	106	17
5/8/2018	5/9/2018	5/9/2018	11.5	8.5	9.66	-7.8	42,000	105	19
5/9/2018	5/10/2018	5/10/2018	9	5	7.58	-2.08	50,400	119	18
5/10/2018	5/11/2018	5/12/2018	13.5	11.5	12.56	4.98	64,800	79	16

Trade date	Delivery start date	Delivery end date	High price $/MWh	Low price $/MWh	Wtd avg price $/MWh	Change	Daily volume MWh	Number of trades	Number of counterparties
5/11/2018	5/14/2018	5/14/2018	23	19	20.45	7.89	30,000	67	20
5/14/2018	5/15/2018	5/15/2018	18.5	16.25	17.21	-3.24	31,600	75	16
5/15/2018	5/16/2018	5/16/2018	14	9	10.51	-6.7	37,600	83	18
5/16/2018	5/17/2018	5/17/2018	9.5	7	8.29	-2.22	39,200	97	18
5/17/2018	5/18/2018	5/19/2018	10	5	6.97	-1.32	51,200	62	19
5/18/2018	5/21/2018	5/21/2018	18	8.25	11.76	4.79	49,200	119	19
5/21/2018	5/22/2018	5/22/2018	19.5	15.5	17.16	5.4	48,400	118	19
5/22/2018	5/23/2018	5/23/2018	19.5	17.5	18.28	1.12	47,600	111	18
5/23/2018	5/24/2018	5/25/2018	13	10	11.45	-6.83	64,000	80	17
5/24/2018	5/26/2018	5/26/2018	0.25	-1	-0.18	-11.63	20,400	44	17
5/25/2018	5/29/2018	5/29/2018	12	9	10.78	10.96	29,600	72	17
5/29/2018	5/30/2018	5/30/2018	15.5	13.5	14.55	3.77	22,800	50	15
5/30/2018	5/31/2018	5/31/2018	7.5	4	6.49	-8.06	49,600	116	18
5/31/2018	6/1/2018	6/2/2018	8	4	5.32	-1.17	74,400	91	19
6/1/2018	6/4/2018	6/4/2018	14.25	13	13.93	8.61	36,800	87	20
6/4/2018	6/5/2018	6/5/2018	16.75	12.25	14.98	1.05	31,200	74	16
6/5/2018	6/6/2018	6/6/2018	20.75	20	20.38	5.4	24,000	59	16
6/6/2018	6/7/2018	6/7/2018	17.75	15.75	16.72	-3.66	40,000	98	16
6/7/2018	6/8/2018	6/9/2018	15	13	13.93	-2.79	47,200	59	18
6/8/2018	6/11/2018	6/10/2018	21	18	19.58	5.65	40,000	95	19
6/11/2018	6/12/2018	6/12/2018	27	21	23.99	4.41	42,800	104	21
6/12/2018	6/13/2018	6/13/2018	19.25	16.75	17.94	-6.05	32,400	81	19
6/13/2018	6/14/2018	6/14/2018	24	22	23.28	5.34	32,000	79	19
6/14/2018	6/15/2018	6/16/2018	23	20.75	21.73	-1.55	44,000	53	16
6/15/2018	6/18/2018	6/18/2018	29	22	25.26	3.53	22,800	57	18
6/18/2018	6/19/2018	6/19/2018	26	23.5	25.21	-0.05	25,600	63	19
6/19/2018	6/20/2018	6/20/2018	28	25.5	26.55	1.34	29,200	73	19
6/20/2018	6/21/2018	6/21/2018	18	16	17.33	-9.22	39,200	98	19
6/21/2018	6/22/2018	6/23/2018	16	14.25	14.91	-2.42	35,200	40	15
6/22/2018	6/25/2018	6/25/2018	13.25	12.75	13.01	-1.9	11,600	29	14
6/25/2018	6/26/2018	6/26/2018	18	16.25	17.36	4.35	23,200	58	17
6/26/2018	6/27/2018	6/27/2018	17	14.75	15.65	-1.71	22,400	55	16
6/27/2018	6/28/2018	6/28/2018	12	8.5	9.78	-5.87	22,000	54	17
6/28/2018	6/29/2018	6/30/2018	13	8	10.13	0.35	57,600	71	20
6/29/2018	7/2/2018	7/2/2018	17.25	15.5	16.59	6.46	30,800	75	18
7/2/2018	7/3/2018	7/3/2018	28.75	24.5	26.03	9.44	19,600	49	18
7/3/2018	7/5/2018	7/5/2018	46.5	40	42.81	16.78	30,000	61	18
7/5/2018	7/6/2018	7/7/2018	37	28	29.95	-12.86	43,200	54	17
7/6/2018	7/9/2018	7/9/2018	27	26	26.6	-3.35	5,200	13	9
7/9/2018	7/10/2018	7/10/2018	27	25.5	25.94	-0.66	22,000	55	18
7/10/2018	7/11/2018	7/11/2018	42	36	38.69	12.75	18,000	45	15
7/11/2018	7/12/2018	7/12/2018	51.5	48	50	11.31	14,400	36	19
7/12/2018	7/13/2018	7/14/2018	38.25	37	37.9	-12.1	18,400	23	11
7/13/2018	7/16/2018	7/16/2018	56	50	54.42	16.52	19,200	44	16
7/16/2018	7/17/2018	7/17/2018	47	37.5	39.63	-14.79	13,600	34	15
7/17/2018	7/18/2018	7/18/2018	33	29	31.43	-8.2	17,200	43	18
7/18/2018	7/19/2018	7/19/2018	32	28.5	30.18	-1.25	17,600	38	19
7/19/2018	7/20/2018	7/21/2018	44	38.5	40.31	10.13	40,000	48	18
7/20/2018	7/23/2018	7/23/2018	210	185	197.94	157.63	19,200	46	16
7/23/2018	7/24/2018	7/24/2018	250	200	217.94	20	14,000	35	17

Trade date	Delivery start date	Delivery end date	High price $/MWh	Low price $/MWh	Wtd avg price $/MWh	Change	Daily volume MWh	Number of trades	Number of counterparties
7/24/2018	7/25/2018	7/25/2018	225	200	214.62	-3.32	10,400	23	13
7/25/2018	7/26/2018	7/26/2018	200	182	194.83	-19.79	12,000	30	15
7/26/2018	7/27/2018	7/28/2018	95	80	87.05	-107.78	45,600	57	16
7/27/2018	7/30/2018	7/30/2018	118	93	105.7	18.65	26,000	61	20
7/30/2018	7/31/2018	7/31/2018	103	83.5	93.35	-12.35	22,000	53	18
7/31/2018	1/18/2008	1/18/2008	78	72	75.51	-17.84	33,600	84	20
8/1/2018	2/18/2008	2/18/2008	65	60	62.84	-12.67	26,000	65	19
8/2/2018	3/18/2008	4/18/2008	64	47	58.69	-4.15	21,600	27	15
8/3/2018	6/18/2008	6/18/2008	285	225	254.31	195.62	10,400	26	12
8/6/2018	7/18/2008	7/18/2008	310	265	300.52	46.21	11,600	28	11
8/7/2018	8/18/2008	8/18/2008	175	135	147.83	-152.69	16,800	42	16
8/8/2018	9/18/2008	9/18/2008	140	124	131.15	-16.68	25,200	62	21
8/9/2018	10/18/2008	11/18/2008	65	51	53.67	-77.48	49,600	55	16
8/10/2018	8/13/2018	8/13/2018	90	80	83.72	30.05	24,000	59	16
8/13/2018	8/14/2018	8/14/2018	89.5	82	85.84	2.12	19,200	47	19
8/14/2018	8/15/2018	8/15/2018	68	62	64.1	-21.74	21,200	53	17
8/15/2018	8/16/2018	8/16/2018	55	45	48.29	-15.81	22,800	57	16
8/16/2018	8/17/2018	8/18/2018	37.75	34.75	35.79	-12.5	36,000	45	13
8/17/2018	8/20/2018	8/20/2018	55	47	49.29	13.5	16,400	40	16
8/20/2018	8/21/2018	8/21/2018	51	38	45.87	-3.42	18,400	46	19
8/21/2018	8/22/2018	8/22/2018	33	31.5	31.91	-13.96	11,600	29	15
8/22/2018	8/23/2018	8/23/2018	25.5	24.25	24.73	-7.18	20,800	52	15
8/23/2018	8/24/2018	8/25/2018	23	19.25	22.27	-2.46	25,600	32	13
8/24/2018	8/27/2018	8/27/2018	30	26	28.15	5.88	26,400	63	18
8/27/2018	8/28/2018	8/28/2018	35.25	32	34.07	5.92	18,400	46	13
8/28/2018	8/29/2018	8/29/2018	27.5	25.5	26.58	-7.49	18,400	45	12
8/29/2018	8/30/2018	8/31/2018	27.75	25.25	26.73	0.15	26,400	33	16
8/30/2018	9/1/2018	9/1/2018	24.5	22.75	23.56	-3.17	30,000	74	15
8/31/2018	9/4/2018	9/4/2018	34.25	28.5	32.76	9.2	20,800	52	19
9/4/2018	9/5/2018	9/5/2018	40.25	34	38.88	6.12	28,000	69	15
9/5/2018	9/6/2018	9/6/2018	36.5	34.5	35.67	-3.21	28,800	70	16
9/6/2018	9/7/2018	9/8/2018	29	28	28.3	-7.37	20,000	25	14
9/7/2018	9/10/2018	9/10/2018	27.75	26	26.15	-2.15	18,000	41	17
9/10/2018	9/11/2018	9/11/2018	26.5	23.75	25.12	-1.03	18,800	47	18
9/11/2018	9/12/2018	9/12/2018	27.95	26	27.05	1.93	19,200	47	18
9/12/2018	9/13/2018	9/13/2018	29	26.5	27.81	0.76	15,200	38	19
9/13/2018	9/14/2018	9/15/2018	29.25	27	28.25	0.44	33,600	42	17
9/14/2018	9/17/2018	9/17/2018	30.5	27	28.91	0.66	19,600	49	17
9/17/2018	9/18/2018	9/18/2018	29.75	28	28.84	-0.07	18,400	46	17
9/18/2018	9/19/2018	9/19/2018	28.25	27	27.54	-1.3	18,000	43	20
9/19/2018	9/20/2018	9/20/2018	27.25	26.5	27.01	-0.53	19,200	44	16
9/20/2018	9/21/2018	9/22/2018	28.25	27.75	28.04	1.03	24,800	30	15
9/21/2018	9/24/2018	9/24/2018	28.75	26.25	28.26	0.22	18,800	46	18
9/24/2018	9/25/2018	9/25/2018	29	28	28.18	-0.08	11,200	28	13
9/25/2018	9/26/2018	9/26/2018	32.75	30	31.57	3.39	27,200	66	20
9/26/2018	9/27/2018	9/28/2018	32	30	31.28	-0.29	38,400	46	16
9/27/2018	9/29/2018	9/29/2018	27.25	25.75	26.18	-5.1	10,800	27	14
9/28/2018	10/1/2018	10/1/2018	29.5	26.5	28.81	2.63	17,200	43	15
10/1/2018	10/2/2018	10/2/2018	24.75	23	23.81	-5	28,000	70	18
10/2/2018	10/3/2018	10/3/2018	35	30	32.27	8.46	28,000	70	20

Trade date	Delivery start date	Delivery end date	High price $/MWh	Low price $/MWh	Wtd avg price $/MWh	Change	Daily volume MWh	Number of trades	Number of counterparties
10/3/2018	10/4/2018	10/4/2018	34.5	31	32.51	0.24	18,400	46	18
10/4/2018	10/5/2018	10/6/2018	37	32	35.32	2.81	65,600	80	20
10/5/2018	10/8/2018	10/8/2018	37.75	36.25	36.9	1.58	26,800	67	18
10/8/2018	10/9/2018	10/9/2018	36.5	35	35.96	-0.94	25,600	64	18
10/9/2018	10/10/2018	10/10/2018	37.5	35.25	36.07	0.11	24,800	62	18
10/10/2018	10/11/2018	10/11/2018	150	65	108.03	71.96	39,600	98	22
10/11/2018	10/12/2018	10/13/2018	37	34	35.69	-72.34	34,400	43	17
10/12/2018	10/15/2018	10/15/2018	39	34	37.42	1.73	28,000	69	17
10/15/2018	10/16/2018	10/16/2018	69	42	61.14	23.72	42,000	92	19
10/16/2018	10/17/2018	10/17/2018	45	42	43.41	-17.73	17,200	43	17
10/17/2018	10/18/2018	10/18/2018	47	42.75	44.78	1.37	24,000	59	15
10/18/2018	10/19/2018	10/20/2018	51	42	47.75	2.97	19,200	23	15
10/19/2018	10/22/2018	10/22/2018	60	45.5	51.06	3.31	22,000	53	15
10/22/2018	10/23/2018	10/23/2018	60	54.25	55.6	4.54	19,200	46	17
10/23/2018	10/24/2018	10/24/2018	55.5	51	53.63	-1.97	24,000	57	17

Appendix D: Memorandum of Understanding

Memorandum of Understanding

Between
Clean Energy Association of BC
and
British Columbia Hydro and Power Authority
and
Government of British Columbia

This Memorandum of Understanding (MOU) between the Clean Energy Association of BC (Clean Energy BC), representing the independent power sector, the BC Hydro and Power Authority (BC Hydro), the Crown Corporation responsible for providing affordable, reliable and clean electricity and the Government of British Columbia, represented by the Ministry of Energy and Mines (Government) sets out the goals and activities the parties will undertake to secure opportunities that will both benefit ratepayers and grow the independent power sector in British Columbia.

Background

The independent power sector is an important partner and supplier to BC Hydro, providing a significant and growing amount of British Columbia's energy needs through more than 100 electricity purchase agreements across a wide range of resource types including hydro, biomass, wind, solar and natural gas.

Government has fostered a robust independent power sector in British Columbia with the 2002 and 2007 Energy Plans which stated the private sector will develop new electricity generation facilities, while BC Hydro continues to upgrade and expand existing infrastructure and with government's approval, is constructing Site C. Additionally, the Minister of Energy and Mines' 2015 Mandate Letter states government will continue working with BC Hydro and Clean Energy BC to identify further opportunities for private clean energy producers in British Columbia.

The sector adds value to BC Hydro and to British Columbia by supporting regional economic development, advancing renewable technologies, assuming and managing technical and financial risks and fostering partnerships with First Nations and communities.

BC Hydro has a responsibility to deliver reliable, affordable and clean electricity and Government has put in place a 10 Year Plan to provide ratepayers with certainty by keeping rates low and predictable.

Clean Energy BC is well positioned to act as the representative of the independent power sector in this agreement as it has represented the entire sector in British Columbia for 25 years and has 160 members across a wide-range of developed and emerging energy technologies. Government and BC Hydro will continue to collaborate generally with other renewable power associations, notwithstanding that other renewable power associations are not signatories to this agreement.

Clean Energy BC, BC Hydro and Government have a mutual interest in seeing all of these objectives accomplished and recognize that greater engagement and partnership is the most effective way to manage divergent pressures and secure opportunities that can both benefit ratepayers and grow the independent power sector.

Purpose

This MOU will support a stronger relationship between Clean Energy BC, BC Hydro and Government. It will provide a framework for constructive and ongoing engagement that provides all parties with certainty and stability. It will facilitate collaboration on key issues to strengthen British Columbia's competitive advantage of reliable and affordable clean electricity and support continued investment and growth in the independent power sector.

Goals

These goals will be accomplished by undertaking the following activities, within the framework of the 10 Year Plan for BC Hydro rates.

1. The parties agree that collaboration, open information sharing and transparency are the foundation of any successful partnership and commit to the following actions to support these objectives:
   a. *Once a year, the Chief Executive Officer and other key members of the Executive Team of BC Hydro and the Minister, Deputy Minister and appropriate Assistant Deputy Minister of the Ministry of Energy and Mines will meet with the Board of Directors of Clean Energy BC.*
   b. *Once a year, designated members of the Board of Directors of Clean Energy BC and BC Hydro will host a meeting to help foster a collaborative relationship.*
2. The parties agree the independent power sector is a British Columbia success story and commit to coordinating communications to promote an understanding of the benefits of the sector's current operations and future growth including the value to the ratepayer and taxpayer and cost competitiveness.
3. The parties recognize the importance of securing economic opportunities for First Nations and the role all parties, including the independent power sector, must have in enabling these opportunities to be realized. The parties also recognize that to advance the development of British Columbia's clean energy resources, it is appropriate and advantageous to work collaboratively together with First Nations as partners to develop shared objectives and actions and to build lasting relationships. Therefore, the parties agree to explore opportunities with First Nations that will support the development and stewardship of British Columbia's clean energy resources.
4. The parties agree to work together to share information on environmental management and stewardship as appropriate.
5. The parties recognize clean energy projects can play an important role for rural communities and agree to support community knowledge on potential benefits and opportunities.
6. The parties agree to engage together transparently on BC Hydro's Integrated Resource Plan review and policy for electricity purchase agreement renewals. This engagement will include:
   a. *The development of various load growth scenarios and contingency plans for those scenarios.*
   b. *The development of resource options and costs.*
   c. *An understanding of how load, demand side measures and supply forecasts are developed by BC Hydro and the various factors that impact those forecasts, including any additional information that the parties could provide to inform those forecasts.*
   d. *An understanding of demand side measures targets and programs including whether targets are being met and if programs are cost effective compared to new generation options, recognizing that BC Hydro must also comply with the requirements of the Demand Side Measures Regulation under the Utilities Commission Act.*
7. In addition to the Integrated Resource Plan review, Clean Energy BC and BC Hydro agree to continuous processes to review the issues listed under item 6 as well as an ongoing review of innovative and emerging technologies in renewable energy. This will take place through an ongoing series of workshops and the parties will meet at least quarterly.
8. Clean Energy BC and BC Hydro also agree to a continuous process of evaluation and improvement of BC Hydro's procurement processes for acquiring independent power resources, including the Standing Offer Program and a review of successful procurement practices in other jurisdictions.
9. The parties agree that extending the grid for suppliers and customers to support economic development is a priority and to support this objective they should explore improvements to extension and interconnection policies including potential roles for the independent power sector as well as process and timeline commitments.
10. The parties agree that advancing the electrification of key sectors of the economy can make an important contribution to the achievement of British Columbia's greenhouse gas reduction targets and climate action goals and that they should explore how each can contribute to ensuring this opportunity is realized including enabling greater export opportunities to neighbouring regions to facilitate reductions to their emissions, provided those opportunities are cost effective for ratepayers.
11. The parties agree that displacing diesel generation in remote communities through the development of clean energy projects is a priority and that a program should be developed to advance this opportunity on an ongoing basis. The parties also agree that the Government of Canada should be a funding partner with respect to displacing diesel generation in First Nations communities and commit to working together to secure this involvement.

Resources

Each party to this agreement will be responsible for committing the necessary resources to support their active participation in the activities described above.

The parties will each designate two individuals to participate in a steering committee, which will meet at least quarterly, to discuss, prioritize and advance the activities set out in this MOU and report to the authorized signatories on progress.

Duration

This MOU shall become effective upon signature by the authorized officials from the parties and will remain in effect until December 31, 2017 or until terminated by any one of the parties providing at least 30 days notice to the other parties. This agreement may be modified by mutual consent of the authorized officials of the parties.

Signed in , BritishColumbia, this day of in the year 2015.

Hon. Bill Bennett Minister of Energy and Mines	**Jessica McDonald** President and CEO, BC Hydro	**Paul Kariya** Executive Director, Clean Energy BC

Appendix E: Special Direction No. 10 to the BCUC

B.C. Reg. 245/2007 Deposited June 26, 2007
O.C. 508/2007

This archived regulation consolidation is current to January 9, 2009 and includes changes enacted and in force by that date. For the most current information, click here.

Utilities Commission Act

SPECIAL DIRECTION NO. 10 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Contents

Definitions and interpretation

1(1) In this Special Direction:

"Act" means the *Utilities Commission Act*;

"assets" means the generation and storage assets set out in the Schedule to the *BC Hydro Public Power Legacy and Heritage Contract Act*;

"biomass contract" means an energy supply contract entered into by the authority and a proponent of a project selected by the authority as a result of the call for power;

"call for power" means the process to acquire electricity solely from wood biomass being conducted by the authority on the date this Special Direction comes into force;

"critical water conditions" means the most adverse sequence of stream flows occurring within the historical record;

"electricity supply obligations" means

(a) electricity supply obligations for which rates are filed with the commission under section 61 of the Act, and

(b) any other electricity supply obligations that exist at the time this Special Direction comes into force determined by using the authority's mid-level forecasts of its energy requirements and peak load, taking into account demand-side management initiatives, that are accepted by the commission from time to time;

"firm energy capability" means the maximum amount of annual energy that a hydroelectric system can produce under critical water conditions;

"integrated area" means the geographic areas in the Province, other than the non-integrated areas, in which the authority serves customers under its schedules of rates filed with the commission from time to time;

"non-integrated area" means Anahim Lake, Atlin, Bella Bella, Bella Coola, Dease Lake, Eddontenajon, Queen Charlotte Islands and Telegraph Creek District;

"wood biomass" means

(a) wood residue within the meaning of the *Forest Act*,

(b) wood debris from logging, construction or demolition operations,

(c) organic residues from pulp and paper production processes, and

(d) timber, within the meaning of the *Forest Act*, infested by the mountain pine beetle.

(2) The definition of "firm energy capability" in subsection (1) must be interpreted for the purposes of this Special Direction so as to be consistent with the fact that, in 2006, the authority's firm energy capability was 42 600 gigawatt hours.

Application

2 This Special Direction is issued to the commission under section 3 of the Act.

Self-sufficiency

3 Subject to section 5 (2) (a), in regulating, and fixing rates for, the authority, including, without limitation,

(a) considering an application made by the authority for a certificate of public convenience and necessity under section 45 of the Act,

(b) doing anything referred to in section 45 (6.2) (a), (b) or (c) of the Act with respect to a plan filed by the authority under section 45 (6.1) of the Act, and

(c) considering an energy supply contract under section 71 of the Act,

the commission must use the criterion that the authority is to achieve energy and capacity self-sufficiency by becoming capable of

(d) meeting, by 2016 and each year thereafter, the electricity supply obligations, and

(e) exceeding, as soon as practicable but no later than 2026, the electricity supply obligations by at least 3 000 gigawatt hours per year and by the capacity required to integrate that energy in the most cost-effective manner solely from electricity generating facilities within the Province, assuming no more in each year than the firm energy capability from the assets that are hydroelectric facilities.

Biomass contracts

4 In considering a biomass contract under section 71 (2) of the Act, the commission may not find that a biomass contract is not in the public interest solely by reason of the factor described in section 71 (2) (d) of the Act and must be primarily guided by the following factors, which are of material value to the authority's ratepayers:

(a) the acquisition of energy by the authority under a biomass contract will reduce the risk to the authority of future costs associated with the production of gasses that contribute to global climate change;

(b) energy acquired by the authority under a biomass contract will contribute to diversification of the authority's electricity supply portfolio;

(c) a biomass contract will assist the authority to meet its requirements for electrical capacity.

Rates

5 (1) In setting rates for the authority, the commission must ensure that the authority's rates and classes of service available to customers in the non-integrated area, including rates available to customers whose electricity demand is or is likely to be in excess of 45 kV.A, are available to customers who receive electricity service under section 2 of the Remote Communities Regulation.

(2) In setting rates for the authority, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to

(a) achieve energy and capacity self-sufficiency as described in section 3 of this Special Direction,

(b) recover costs incurred as a result of the call for power, including costs incurred in purchasing electricity under a biomass contract, and

(c) recover costs related to the provision of electricity service under section 2 of the Remote Communities Regulation.

[Provisions of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473, relevant to the enactment of this regulation: section 3]
