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Harnessing Nature's Power

KLEANA POWER CORPORATION

August 29, 2017

BCUC INQUIRY RESPECTING SITE C **F 53-1**

British Columbia Utilities Commission
410 – 900 Howe Street
Vancouver, B.C V6Z 2N3

VIA EMAIL – SiteCSubmission@bcuc.com

Attention: British Columbia Utilities Commission Site C Inquiry

Re: Response to BCUC with respect to Independent Review of Site C
Kleana Power Corporation – Kleana Project

On Aug. 2 2017, the Government of British Columbia ordered an independent review of Site C to ensure "we can keep hydro rates affordable," [1]

According to Energy, Mines and Petroleum Resources Minister Michelle Mungall:

> "The previous government refused to allow ***our independent energy watchdog*** to examine the project to determine if it was in the public interest. That was wrong. We're sending this project to the BCUC to ensure we make the right decision for B.C. families."[2]

The terms of reference ("**Terms of Reference**") are set out in the Order in Council[3] and specifically include BCUC responding to:

- Whether BC Hydro ("BCH") is, respecting the project, currently on time and within budget (excluding reserve and including expenditures to date)
- Costs to ratepayers of suspending Site C;
- Costs to ratepayers of terminating Site C;
- Given energy objectives set out in the *Clean Energy Act,* what other commercially feasible generating projects and demand-side management initiatives could provide similar benefits.

By mandating this review, the Government has responded to public concerns about Site C, at least some of which were not adequately addressed in the prior approval process.

[1] https://news.gov.bc.ca/releases/2017EMPR0018-001380 - Quote from Energy, Mines and Petroleum Resources Minister Michelle Mungall.
[2] Ibid.
[3] https://news.gov.bc.ca/files/DEF_terms_of_reference_BCUC.pdf.

Kleana Power Corporation ("**Kleana**") is an interested party and wishes to respond to BCUC. Kleana has the water rights to and wishes to develop one of the largest run-of-river independent power projects ("**IPP**") in North America (the "**Kleana Project**"). Kleana, and many other IPP's, made submissions to the Site C Joint Review Panel Secretariat during the December 2013 hearings on the approval for the Site C Project. Kleana's submission to the Review Panel and Final Closing Remarks (Feb. 3 2014) are attached as Appendix 1 and 2.

BCUC's Terms of Reference include costs to ratepayers and consideration of the portfolio of commercially feasible generating projects which could provide electricity to ratepayers at a lower unit cost. Arguments in favor of Kleana are, if anything, more persuasive than they were at the 2013 hearing. Without limitation, concerns regarding climate change are increasing exponentially.

In this letter, we will briefly outline the Kleana Project and the arguments in favor of this project as an alternative to the proposed Site C Project in conjunction with alternate projects and demand side management or as a compliment to a reduced version of Site C to meet the anticipated demand.

In summary, this letter will demonstrate that the BCUC should very seriously consider whether Site C should proceed, and that the Kleana Project will produce dependable, less costly energy as an alternative.

INTRODUCTION TO KLEANA PROJECT

The Kleana's Project is a proposed run-of-river hydroelectric facility located on Klinaklini River. This Project has a nameplate capacity of 565 MW delivering 2,450 GWh of annual energy. The point of connection to the BC Hydro transmission grid is located at Campbell River.

As stated above, Kleana submitted a presentation to Site C Joint Review Panel on December, 2013 (attached to this letter as Appendix 1). Exhibits 012 and 013 of the Kleana submission describe the technical attributes and benefits of the Kleana Project alone or in tandem with other alternatives to Site C.

Kleana's Kleana Project is also mentioned as an alternative to Site C in submissions by others to the Site C Joint Review Panel. In particular we refer to excerpts from the February 4, 2014 Closing Comments submission of Barton and Davis.[4]

KLEANA'S SUBMISSION TO THE PANEL – Dec. 2013

The main issues addressed in our December 2013 Submission and Final Closing Remarks, still relevant today, are:

[4] See Appendix 3 for Barton & Davis, "Closing Comments on British Columbia Hydro and Power Authority Environmental Impact Statement Application for the Site C Project." February 4, 2014.

1. The history of Kleana's submission for the Clean Power Call 2008

    a. Kleana's submission was removed from the Call because a former Minister of the environment refused to approve a minor amendment to the boundary of a conservancy that was necessary for the project to proceed. Kleana jointly with Da'naxda'xw First Nation had to resort to litigation against the Crown which resolved this issue in favor of Kleana and Da'naxda'xw.
    b. On Sept. 18 2012 (about 6 months ***prior*** to BCH filing its application for Site C), the BC Minister of Energy, Mines and Natural Gas directed BCH to enter into good faith negotiations with Kleana for an Electricity Purchase Agreement ("EPA").[5]
    c. Kleana made three different written offers to BCH in an attempt to frame the terms of the EPA. All were rejected. The second was rejected in Dec. 2014 (***after*** BCH made its application for Site C) on the basis of substantial uncertainty about "Need". ***All three Offers would have resulted in lower prices to BCH than those achieved from Site C (assuming it was built at estimated budget costs at that time).*** We can provide further information and documentation to you on request.
    d. There is clear scientific evidence from Kleana's independent consultants that the power from the Kleana Project will be dependable. In any event, all risks of performance are guaranteed to rate payers by Kleana, unlike Site C.
    e. BCH is failing to take advantage of a great natural resource which will have an order of magnitude less impact than Site C. Furthermore, Kleana has the support of indigenous groups whereas Site C has faced substantial resistance.

WHY KLEANA AS AN ALTERNATIVE TO SITE C

Fundamentally, Kleana is a preferred alternative to Site C because:

- It is a more cost effective alternative to Site C
- It is smaller than Site C, and therefore has a lower risk of creating excess supply
- There is no cost overrun risk to rate payers and cost to build and operate is the responsibility of the Owners
- It has lower actual costs (see "Factors Influencing Costs"…below), lower impacts (which must be included in cost analysis), and lower future risk associated with Climate Change
- It has a more effective delivery point and massive savings in system losses due to backfeed to Vancouver Island
- It has the support of the affected indigenous peoples

[5] See Appendix 4 for full text of the Letter of Direction dated Sept 18, 2014.

- Based on Ministerial Directive, BCH has an obligation to negotiate in good faith with Kleana[6]

All of the foregoing are within the scope of the Terms of Reference. Each of the above factors are elaborated on below.

The Kleana Project can provide installed capacity of 565 MW and minimum annual energy of 2450 GWh. BCH was not correct when making submissions to the Joint Panel in dismissing the Kleana Project. As of October 31, 2013, there were 45 non-storage run-of-river hydropower facilities operating in this province. The average size is 19 MW. Of these 45 operating facilities, 28 have an installed capacity of 10 MW or less. While the largest, at 196 MW, is a cluster of 2 facilities. BCH clearly cannot credibly argue or believe the 565 MW Kleana Project is a typical run-of-river project.

The Kleana Project will benefit from superior catchment characteristics. Further, our hydrology is expected to benefit from climate change, which is the opposite of the expected impacts on the interior of BC.[7]

The Kleana Project can be a compliment or partial alternative to Site C.

Considering the history and facts around the Kleana Project, good engineering practice would have integrated the Kleana Project into an optimization study to determine the optimal size for Site C. This would have potentially reduced the size of the flooded area by the Site C project.

Not only can the Kleana Project deliver 48% of the energy of Site C (2450 GWh vs 5100 GWh), it delivers this energy to the City of Campbell River on Vancouver Island. This is very important strategically for dependable energy delivery, reduced transmission cost and impact.[8]

Just as the 1100 MW Site C benefits from economies of scale, the Kleana Project benefits from economies of scale. Further, our nearby Machmel Project can increase the 565 MW capacity and 2,450 GWh energy from the single Kleana Project by additional 50%. This will further improve our economies of scale.

GRID RELIABILITY AND REDUCTION OF GREENHOUSE GAS EMISSIONS - CLIMATE CHANGE AND CATCHMENT CHARACTERISTICS

The Kleana Project will benefit from superior catchment characteristics compared to Site C by virtue of glacial summer runoff and non-glacial winter precipitation (as compared to typical run-of-the river projects). From our hydrology studies, *Kleana will benefit from climate change*. This is a particularly important point because Kleana's studies are based on changes in the future due to climate change as well as past performance. Today, business and governments demand risk

[6] See "THE MATTER OF LITIGATION AND INDIGENOUS PEOPLE'S SUPPORT below.
[7] See "GRID RELIABILITY AND REDUCTION OF GREENHOUSE GAS EMISSIONS - CLIMATE CHANGE AND CATCHMENT CHARACTERISTICS" below.
[8] See "VANCOUVER ISLAND GRID" below.

analysis taking into consideration climate change, and this applies emphatically to a project like Site C.

We repeatedly asked BCH if they have any in-depth and comprehensive climate change impact modelling (a "stress test") that predicts the performance of Site-C into the future, rather than simply relying on past hydrological records which no longer is the valid climactic paradigm. Clearly climate change will affect the energy production profile of Site-C and if so, will likely have a material impact in determining unit cost of electricity and reliable energy production (both of which are matters BCUC has been tasked with responding to).

BCH never gave Kleana a clear answer (even though question was submitted to the Joint Review Panel by Kleana for response from BCH) on the existence of comprehensive modelling which is an absolute necessity for power production, costs and reliability. BCUC cannot fulfill its mandate to conduct a proper assessment of Site C and the likely impact of Climate Change in the absence of this information. Production risk and associated unit cost increase is a risk which BCH expects rate-payers to bear in the case of Site C, unlike IPP's where BCH demands the unit cost is fixed for the rate payers regardless of Climatic (or in fact other) factors.

The implications of completing Site C as currently planned must, by necessity include proper risk analysis. The resistance of BCH to providing this analysis as part of its mandate to the public is hard to understand.

RISK AND BUDGET – PERFORMANCE

There is inherent risk to the Public of British Columbia with respect to the development of Site C. Apart from the failure of BCH to provide a comprehensive risk analysis of climate change impacts on Site C, the risk of price escalations (already in evidence) is borne by the public, rather than the private developers and financiers in the case of Kleana (and other IPP's). There is no effective way of eliminating this risk at the budget estimate stage, particularly having regard to preliminary work already underway which would result in "sunk costs". The sunk costs must not be used by BCH to bootstrap its economic arguments for Site C. This simply results in additional "moral hazard" for this project.

In addition to "sunk costs", BCH has a vested interest in keeping Site C "in-house". This makes the need for independent review of costs, contingencies and risk mitigation strategies absolutely essential, along with independent review of same, all of which must be taken into account in budgeting.

VANCOUVER ISLAND GRID

In its 2013 submission to BCUC Site C Joint Review Panel, Kleana explains the benefits of its underwater transmission to Northern Vancouver Island.[9] These benefits must be considered by

[9] See page 4 of Appendix 2.

the BCUC as part of grid reliability, elimination of need for transmission capacity upgrades elsewhere in the grid system and costs of transmission losses.

FOOTPRINT AND COST OF POWER

The footprint of Kleana vs. Site C is as follows:[10]

	Site C	Kleana
Energy:	5100 GWh	2450 GWh
Land Footprint:	9100 -10000Hectare	1100 Hectare
Energy Intensity (GWH per Hectare):	0.56-0.51 GWH per Hectare	2.22 GWh per Hectare

Kleana's Energy Intensity is four times that of Site C.

This is fully explained in the Final Closing Remarks and must be seriously considered by the Commission in accordance with its mandate.

THE MATTER OF LITIGATION AND INDIGENOUS PEOPLE'S SUPPORT

Kleana's has as its First Nation partner Da'naxda'xw. Da'naxda'xw fully supports Kleana in its efforts to develop the Kleana Project. Supported by Kleana, our partner Da'naxda'xw is continuing to litigate against the BC Government. There remains considerable exposure to rate-payers as a result of this litigation.

The exposure to litigation and societal costs of the development of Site C in the face of significant opposition by indigenous peoples in the areas impacted by Site C are matters which must be considered in determining the implications of terminating Site C and choosing alternative projects.

SCALED DOWN ALTERNATIVE OF SITE C

BCH and the BC Government have continued to spend money on and make commitments with respect to Site C with BCH then taking the position that Site C is at the point of no return. However, a quick independent study by a qualified arm's length engineering firm can look at the cost of scaling down the size of Site C. There will be some waste of the money spent vis-à-vis the existing work being geared for a larger scale project but it will still be cheaper than the total cost to complete the currently contemplated design. The cost per kwh will increase, but for a much lesser amount of power and for a much reduced footprint. The same optimization study can look into the benefits of synchronizing Site C with a coastal project such as ours. If Kleana were to get the same risk protection from the BC Government as Site C, Kleana could reduce our production price even further while further scaling down.

[10] See page 5 of Appendix 2.

Kleana can provide power where it is needed on the grid. We will have negligible transmission losses compared to massive losses for Site C. While the northwest interior will likely be severely affected by climate change, as stated above our catchment is coastal and proportionally much less glacier-based than a typical high head run-of-the-river-project. The Kleana Project *would actually improve its delivery profile due to potential ongoing impact of climate change*.

Our large scale run-of-river project avoids the cumulative impact of many multiples of small scale projects each on a different creek to produce the same amount of power. Our project is a First Nations partnership project. Our project did not find a single adult salmon in its diversion reach in 3 years of fish studies. We are very confident it would be no net loss and most likely a net benefit project; our science will demonstrate this. We can provide flexibility in bringing power on line in stages, with smaller increments than site C and a schedule arranged accordingly. And we can help reduce the production cost in overall. It might be that instead of a loss, there is a gain in production cost in this mutually scaled down solution. We are certain there will be a definite improvement in the social cost in an optimized solution due to Kleana's reduced footprint per kwh.

FACTORS INFLUENCING BCH AND IPP COSTS – COMMERCIALLY FEASIBLE ALTERNATIVE PROJECTS

When revising procurement practices for IPP's in the early 1990's, BCH shifted all risks (probable and remote) to IPP's resulting in artificially increasing the price of power, but not building into its own cost estimates the same increases. In fact, the rate payers were taking on those risks, though the risk cost was not built into rates. A comprehensive review of BCH construction and maintenance standards compared to their procurement standards for IPP's will demonstrate that Kleana will produce energy at a significantly lower unit cost than Site C with a superior risk profile than Site C and no risk to ratepayers.[11]

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[11] Here is the background: In the early 1990's, the president of Kleana was the CEO of the company which developed the 55 MW Lower Mamquam Project. This project delivered and sold quality power to BCH at a price of $45 per kwh and the plant was operated and maintained conservatively without causing any environmental concerns, but profitably with reasonable return to investors. The government got its full share of taxes, fees and revenues and BCH benefitted from dependable power at a reasonable rate. The question is: how is it that if we built the same plant based on BCH's most recent contract terms at 2008 Clean Call its production cost would be $140 up from $45? The construction materials did not triple in 20 years. Equipment prices did not triple? Wages did not triple? And interest costs for construction went down by more than half. So what is the explanation?

The Government at that time, in effect, told BCH that it wanted the private sector to bring on new generation, which resulted in BCH creating the system that was then referred to as Clean Calls. BCH took the position that rate payers should not take ***any*** risks, subsequently not objected to by the government, probably because it sounded great. The principles of procurement in the Clean Call contracts were designed accordingly.

A simplistic example of the repercussions is: if a developer in Vancouver, an earthquake zone, wants to build a 30 storey building with no risk of collapse in the event of any future earthquake regardless of magnitude or probability of occurrence, what would be the cost? The answer is basic science. The cost of zero probability of failure is infinite. BCH defined all the r risks that they can and loaded them into their template contracts. They also severely limited the power profile that could be delivered from a project seasonally. Normally private developers should have refused to enter into those contracts and government should have established an independent objective body (not BCH) to make the procurement decision, subsequently to be managed by BCH.

This procurement process, controlled by BCH, resulted in the following:

1. To compensate for the risk, just on paper, the financing costs of the lenders and the risk avoidance of the contractors, as well delivery restrictions and penalties being priced in made the cost of production instantly triple. It did not triple in 20 years. It tripled immediately with the announcement of BCH of the new procurement regime. BCH then stated that the private sector is very expensive. (*continued on next page*)
2. Many inexperienced developers holding water rights who were allowed to bid in did so with lower prices without taking the risks associated with the new procurement requirement fully into consideration. They then had to abandon their bids. BCH later used this high attrition rate for IPP projects as an argument that IPP's were unreliable generally.
3. Some IPP's who signed EPA's were able to deliver on their projects but had to struggle by cutting back on the quality of construction and operation. That resulted in delivery of lower quality power and environmental mishaps. BCH then argued that IPP's generally delivered a low quality product, unreliably and at a very high price.

SUMMARY AND REQUEST TO MAKE PERSONAL APPEARANCE BEFORE BCUC

For the above reasons, Kleana recommends BCUC suspend or terminate Site C as currently planned. Kleana requests that BCUC allow an in-person appearance before BCUC to provide a supplemental and more complete brief on the issues vital to the interests of the people of British Columbia. Kleana will provide full text of all materials referred to herein on request by BCUC.

Regards

Kleana Power Corporation

Per_____

Alexander N. Eunall, President

Kleana Submission - Schedule of Appendices

Appendix 1 – 2013 Kleana Submission to BCUC – Presentation of the Kleana Power Project

Appendix 1 – 2013 Kleana Submission to BCUC – Information Sheet on Kleana Power Corporation

Appendix 2 – 2014 Kleana Closing Remarks

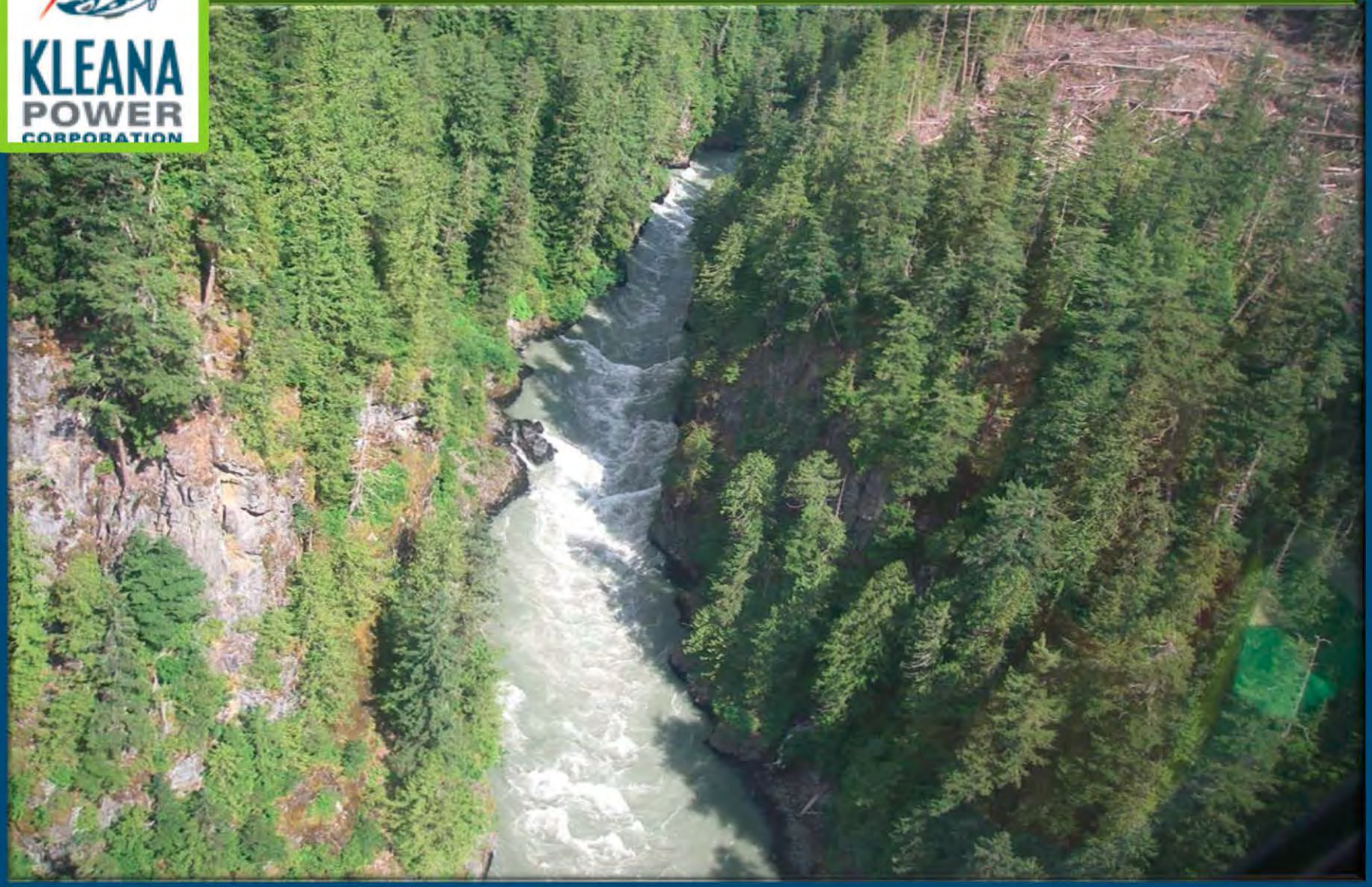
Appendix 3 – Barton & Davis, Cover Letter and Closing Comments dated Feb 4, 2015

Appendix 4 – Ministerial Letter of Direction dated Sept 18, 2012

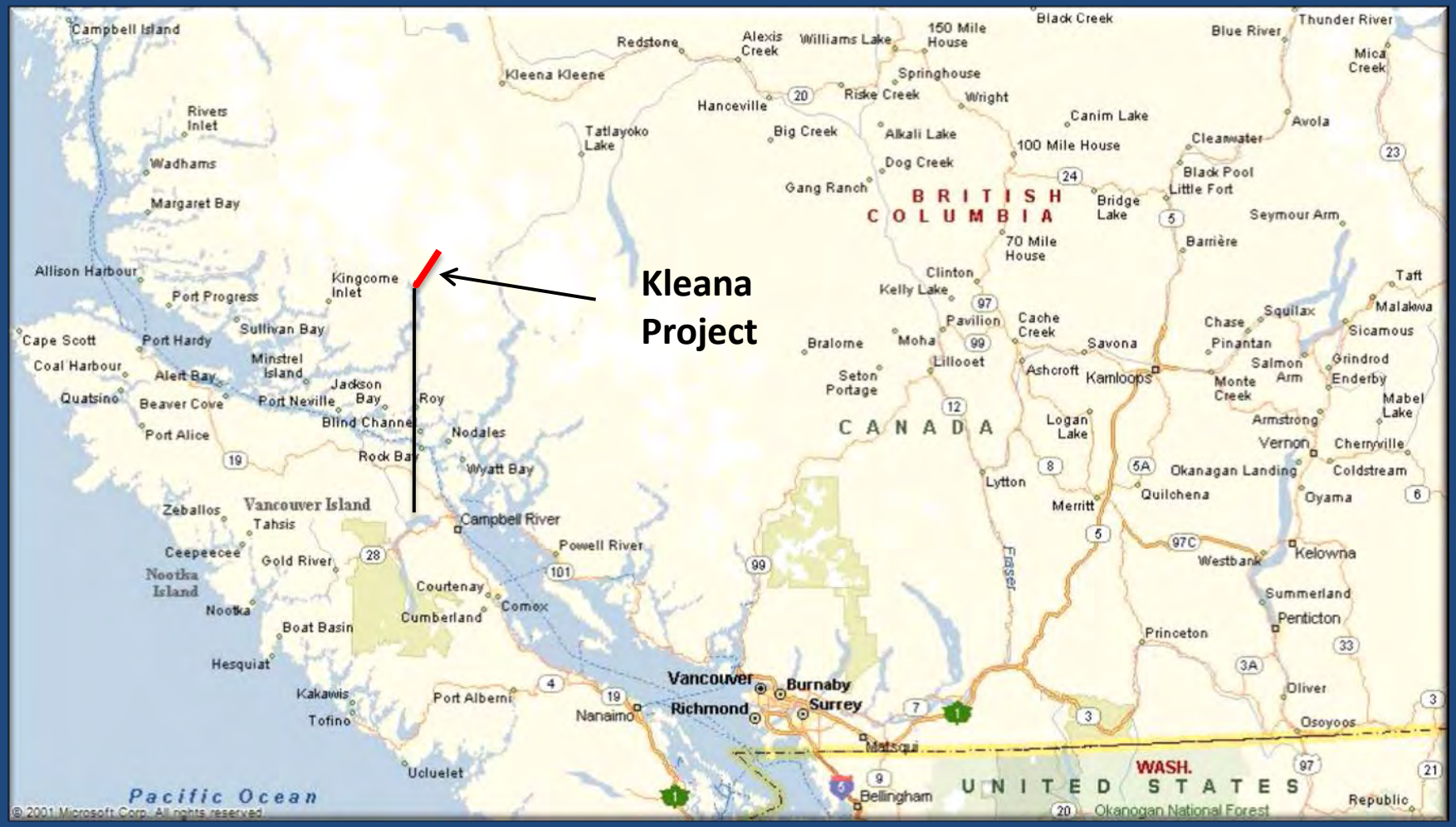
"Appendix 1"

Kleana Power Project

Hearing Exhibit 012: Presentation on the Kleana Power Project by Dr. Alexander Eunall on Day 2 of the Topic-Specific Session on Need, Purpose and Alternatives in Fort St. John, BC, December 10, 2013



Kleana Power – Project Map



Kleana Power – Highlights

- Kleana Power Project Highlights with New Boundary:
  - Minimum Nameplate capacity 565 MW
  - Minimum Annual energy delivered 2,450 GWh
  - Our nearby Machmel Project, if added, can increase capacity and energy by 50%
  - Projected Total Capex of $2.4 billion, under $4,250/kW installed, (For reference Site C projection is $7,200/kW)
  - Annual GHG emission reduction of 1,000,000 tonnes

- Kleana Power Project Technical Highlights:
  - 6 X 94 MW Pelton units to avoid downstream fishery impacts in case of load rejections
  - Dual circuit 230 kV transmission line to Campbell River from Mainland avoiding TL losses from distant sources of energy
  - Five year construction timetable
  - All infrastructure paid by private sector transferable to public after period of operations
  - Run of river, 9 meter diversion weir, no reservoir, tiny head pond with no fluctuations
  - Entire diversion underground with no surface footprint

The Kleana Power Advantage

- Broad local First Nation support and partnerships
- One of the lowest surface footprint per kwh for any known water based project
- No adult salmon in the diversion reach found in 4 years of studies. Due to significant fish enhancement commitments downstream, a net benefit is expected
- Minimized footprint results in avoided material impact on wildlife or recreational users
- Unique catchment atypical of high head run of the river, a mixture of glacial fed summer runoff with non glacial winter precipitation. Its generation expected to be positively affected by climate change perhaps unlike the interior of the province.

Comparison with Site C

	Site C	Kleana
Capacity (MW)	1,100	565
Energy (GWh)	5,100	2,450
Reservoir/Headpond Size	9,100 Hectares	40 Hectares
Reservoir/Headpond Length	83 Kilometers	0.8 Kilometer
Delivery	Peace River	Campbell River
Risk Allocation		
Capital Cost*	Ratepayer	Kleana
Performance*	Ratepayer	Kleana
* These differences should be monetized in any comparison		

Project Status

- Fixed firm price bid into last Clean Call. Project was a finalist but was denied a contract because of a political decision made by a past Minister of Environment (2010).
- Courts quashed the Minister's decision [basis: inadequate consultation with FN partner]. Legislative Assembly enacted a law to fix the problem caused by the Minister (2012).
- By 2012 Clean Call was long over. Minister of Energy (2012) directed BCH to negotiate with Kleana "in good faith". While further litigation on this is possible, BC Hydro's position on what constitutes "current conditions" remains unclear; especially in light of Site C.
- Given that BCH is required to negotiate with Kleana "in good faith", Kleana should be considered as a partial alternative or a complement to Site C. This may result in less area flooded and less impact to the environment.
- Project technical and permitting advanced, and sponsors remain fully committed.

Summary

- Very competitive cost compared to BCH alternative renewable portfolio costs
- Ratepayers bear no capital cost, performance or schedule risk
- Vancouver Island delivery is significant as it brings source near where support needed
- Extremely low generation footprint per kwh basis
- Environmental impacts, if any, can be mitigated
- Net benefit to Salmon fishery projected
- First Nation participation and support
- Projected to perform well under climate change conditions

Kleana (+Machmel) project should be considered either as part of an alternative renewable portfolio or as a complement to Site C.

Questions

- Was the Kleana Power Project considered by BC Hydro as a significant partial alternative or as a complement to Site C? If not, why not?
- Has BC Hydro incorporated climate change in its projections for the performance of Site C? If so, please provide the model and assumptions that were used for the analysis. If it has not been incorporated, please explain why.

“Appendix 1”

KLEANA POWER CORPORATION

nanwakolas COUNCIL

K'ómoks First Nation

Kleana run-of-river hydroelectric project

Kleana Power Corporation and the Da'naxda'xw/Awaetlala, Comox and Campbell River First Nations are proposing the Kleana run-of-river hydroelectric project on the Klinaklini River, north of Knight Inlet on BC's central coast.

The Kleana project would have the smallest environmental footprint per kilowatt-hour of electricity of any new greenfield power project in British Columbia and would be one of the most sustainable and cost competitive sources of clean energy in North America.

The Kleana project offers significant and lasting economic and social benefits for First Nations, coastal communities and all British Columbians. And with a proposed capacity of approximately 565 megawatts, the Kleana project is a superb resource to help meet BC Hydro's need for capacity and energy in the coming years.

A true run-of-river project to harness the power of nature

The generous gradient and high flow of the KlinaKlini River, and the high level of electric capacity this can produce, make the Kleana project a truly unique clean energy source.

Kleana would be a true run-of-river hydroelectric project. It would incorporate a 9-metre high intake weir with a small, non-fluctuating headpond on the river's upper reaches with absolutely no capacity for water storage. The project would not use a dam or storage reservoir.

Water would be diverted through an underground tunnel to turbines to generate electricity before it is returned unaltered to the river. Using a diversion tunnel instead of an above ground penstock to move water to the turbines greatly minimizes the loss of forest and wildlife habitat.

A net benefit for fish populations

The Kleana project has the potential to deliver a net benefit to fish populations. Four years of field studies demonstrate that there are 21 natural fish obstacles in the Klinaklini canyon. A falls located approximately 3 km downstream from the proposed intake weir and a second major barrier some 15 km downstream from the proposed intake prevent the upstream migration of salmon. Moreover, no adult salmon have been identified upriver from the proposed powerhouse, which is also located many miles upstream from the Eulachon grounds.

There will be no significant impacts to eulachon, salmon or other fish populations, and no reduction in wildlife populations is expected.

Project design has limited the water diversion to the least productive section of the KlinaKlini River. And based on research to date, the diversion canyon has been shown to have low habitat productivity because of high flows, low temperatures and high turbidity during the growing season.

With the appropriate environmental design and compensation measures, aquatic production in more than 15 km of the river would increase with the operation of the project, creating the opportunity for a net benefit to the fishery of the Klinaklini River.

Further, Kleana Power is committed to funding a $5 million trust that will finance an ongoing salmon recovery plan to fund local habitat and stock restoration and improve the productivity of salmon grounds along the lower Klinaklini River and Knight Inlet.

Amending the Upper KlinaKlini Conservancy boundary

The Da'naxda'xw/Awaetlala offered up more than 95,000 hectares of their traditional lands to create the Upper KlinaKlini Conservancy and were intimately involved in developing the eco-based management system for the Great Bear Rainforest. Before the conservancy was created, the Da'naxda'xw/Awaetlala asked the Province to set aside a very small piece of their territory from the proposed conservancy to scientifically assess the environmental impact of the proposed project.

Unfortunately the Province failed to set this land aside, but in May 2011 the courts ordered the Province to restore the Honour of the Crown and enter into government-to-government dialogue with the Da'naxda'xw/Awaetlala with a view to considering a reasonable accommodation of their interest to enable an environmental assessment of the project.

In June 2012, the Province modified the conservancy's boundary. The modification is 62 hectares, or approximately one seventh of one percent of the 40,000 hectare conservancy, and is very small — and in no way threatens the Coast Land Use Decision.

The boundary modification respects and accommodates the Da'naxda'xw/Awaetlala First Nation's Aboriginal title and will enable the environmental assessment of the Kleana project. If the project is not approved under BC's Environmental Assessment Act, the land will be placed back in the conservancy.

A better, more prosperous future for First Nations and coastal communities

The Kleana project is a game-changing economic opportunity for the Da'naxda'xw/Awaetlala, Comox and Campbell River First Nations that offers meaningful economic benefits to coastal communities and all British Columbians.

During the three peak years of its construction, approximately 800 to 1,100 workers would be required – the total value of wages paid during this period is estimated at more than $200 million.

In addition to providing jobs to local individuals and contractors, the project would create opportunities for local providers of goods and services during construction and ongoing operations. The project would also make a sizeable contribution to the provincial economy through payment of water rentals, and property, income and sales taxes.

“Appendix 2”

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Harnessing Nature's Power

KLEANA POWER CORPORATION

February 3, 2014

BY E-MAIL (SiteCReview@ceaa-acee.gc.ca)

Site C Joint Review Panel Secretariat
Courtney Trevis, Panel Co-Manager
160 Elgin Street, 22nd Floor
Ottawa ON K1A 0H3

Brian Murphy, Panel Co-Manager
4th floor, 836 Yates St., PO Box 9426
Victoria BC V8W 9V1

Dear Sirs/Mesdames:

Re: Closing Remarks by Kleana Power Corporation

Since our presentation to the Panel on December 10, 2013, we have followed the Hearing.

We are in receipt of the Transcript from the Questions & Answers on January 23, 2014 (the "Q&A Transcript"; CEAR 2709) and the Kleana-related questions from on January 15, 2014 (CEAR 2479) and January 21, 2014 (CEAR 2626).

Below are the closing remarks of Kleana Power Corporation providing important facts about the project and clarifying the record in case some of the statements that were made led to inaccurate conclusions.

WHAT IS THE COST OF THE POWER FROM THE KLEANA PROJECT?

Mr. Reimann of BC Hydro dismisses Kleana on the basis that this 565 MW proposed project has similar cost and energy profile as a typical run-of-river project:

"And a rough assessment of this project has the adjusted unit energy cost of it north of $140 per megawatt hour.

So in terms of the analysis that we've done in the portfolio PV analysis, the Kleana project is not substantially different than the run-of-river options that we'd shown in there. A similar sort of price; a similar sort of profile in terms of the energy delivered." (Page 148 of the Q&A Transcript)

It is impossible for us to comprehend the type of rough assessment that led to the results mentioned above; however, we can advise the Panel that our estimated AUEC is far below $140 per MWh. While the Panel has not been provided our bid to the 2008 Clean Power Call because of the confidentiality restrictions of the call itself, we confirm the financial assumptions listed in the January 21, 2014 questions of Mr. Barton on Page 7 of CEAR 2626. We generally agree with the

calculations of a UEC of $80 and an AUEC of $90 (Page 7 of CEAR 2626). We further note that BC Hydro did not answer the questions of whether they disagreed with the UEC and AUEC numbers on Pages 7-10 of the January 21, 2014 Questions by Mr. Barton (CEAR 2626).

WHY DID KLEANA MAKE THE INITIAL SUBMISSION TO THE PANEL?

Kleana was a finalist in the 2008 Clean Power Call. Kleana was removed from the 2008 Clean Power Call only after a former Minister of Environment refused to approve a minor amendment to the boundary of a conservancy that was necessary for the project to proceed. Kleana and its First Nation partner were left no choice but to commence litigation. The Supreme Court of British Columbia quashed the Minister of Environment's decision. The conservancy issue is now resolved.

On September 18, 2012, the Minister of Energy, Mines and Natural Gas directed BC Hydro to enter into good faith negotiations with Kleana for an Electricity Purchase Agreement ("EPA") with respect to the project.

This was nearly 6 months prior to the filing of the Site C EIS Application on January 28, 2013.

Since then we received rejections and no counteroffers to any of our three offers to BC Hydro:

1. we offered in the fall of 2012 to negotiate on the terms of the 2008 Clean Power Call – our offer was priced within the lowest 10% of accepted bids;

2. we offered on December 18, 2012 to match the terms of BC Hydro's Standing Offer Program with a price of $102/MWh – in their rejection on December 24, 2012 BC Hydro among other things mentioned substantial uncertainty about the "Need". BC Hydro described the "Need" the following month in the Site C EIS Application on January 28, 2013.

3. we offered on December 19, 2013 to match the price for power of Site C.

Furthermore, we do not understand how the modelling of BC Hydro can result in wind being the preferred resource when Kleana was offered to BC Hydro at $102 on December 18, 2012. Because our pricing is lower than any wind project, we are puzzled by the statement by Mr. Reimann of BC Hydro at Page 148-149 of the Q&A Transcript:

"And, in fact, what we see is that wind is the preferred resource, and -- and that's somewhat different than our last call, but, as we've all discussed, the wind projects have been coming down in cost. And we are now predicting that wind would be the more successful resource, and that's what our portfolio selected."

Perhaps as a result of our submission the Panel will arrive at an equitable answer we can all understand.

IS KLEANA A TYPICAL RUN OF RIVER PROJECT?

The Kleana Power Project can provide installed capacity of 565 MW and minimum annual energy of 2450 GWh (Page 3 of our Presentation). BC Hydro is not correct in dismissing Kleana as an inferior project which has "very little dependable capacity" (Page 145 of the Q&A Transcript).As of October 31, 2013, there are 45 non-storage run of river hydropower facilities which are currently operating in BC. The average size is 19 MW. Of the 45 operating facilities, 28 have an installed capacity of 10 MW or less. Many are smaller than 0.5 MW. While the largest is 196 MW, this is a cluster of 2 facilities. It is incomprehensible for BC Hydro to believe the 565 MW Kleana is a typical run of river project.

Also as we explained in Page 4 of our Presentation, the Kleana project will benefit from superior catchment characteristics by virtue of glacial summer runoff and non-glacial winter precipitation (as compared to typical run of the river projects). Also, our hydrology is expected to benefit from climate change which is opposite of the expected impacts of the interior of BC.

It is becoming increasingly difficult over the years to monitor the evolution of BC Hydro's terminology describing the electricity it favours and values. Perhaps no other jurisdiction in North America has produced so many. Every description seems to incorporate even more restrictions to a point that very few projects in BC can conform.

While BC Hydro's frequently refers to "Dependable Capacity", their equivalent concept for wind and run of river projects is "Effective Load Carrying Capacity" (ELCC):

"BC Hydro uses ELCC to represent the capacity contribution from intermittent clean or renewable IPP resources such as wind and run-of-river hydro."

(Page 3-4 of 2013 Integrated Resource Plan)

Table 3-13 of the 2013 Integrated Resource Plan illustrates that 24% is the ratio of ELCC to Installed Capacity for potential run of river projects in the Vancouver Island Transmission Region (420 MW of ELCC / 1754 MW of Installed Capacity). Based on this data from BC Hydro, the equivalent dependable capacity of Kleana is 135 MW (24% of 565 MW).

IS KLEANA AN ALTERNATIVE TO SITE C?

Kleana project can be a compliment or partial alternative to Site C.

Considering the history and facts around Kleana project, good engineering practice would have integrated Kleana into an optimization study to determine the optimal size for Site C. This would have potentially reduced the size of the flooded area by the Site C project.

Just as the 1100 MW Site C benefits from economies of scale, Kleana benefits from economies of scale. Further, our nearby Machmell Project can increase by 50% the 565 MW capacity and 2,450 GWh energy from the single Kleana project. This will further improve our economies of scale.

Not only can Kleana deliver 48% of the energy of Site C (2450 GWh vs 5100 GWh), it delivers this energy to the City of Campbell River on Vancouver Island. This is strategically very important. Vancouver Island consumes twice the amount of energy it generates. It relies on three underwater transmission cables from the Lower Mainland to satisfy such load. Adding a fourth transmission line (from Kleana), especially to Northern Vancouver Island, will improve the reliability and strengthen the local grid. Therefore, Kleana can deliver such energy to the load centers of Vancouver and Vancouver Island for a fraction of the cost of new transmission from Fort St. John.We also highlight the planned 708 MW capacity upgrades of Revelstoke #6 (488 MW) and GMS (220 MW) - plus our Kleana and Machmell projects will put a very large dent on the need for the capacity of Site C. There are of course several other projects in the vicinity that if allowed to proceed would surpass this need.

<u>THE VERY IMPORTANT RISK TRANSFER QUESTION</u>

BCH did not respond to the risk comparison question put before them by the panel regarding Kleana. We believe a hefty premium has to be added to the projected Site C costs of power for a fair comparison of price to rate payers.

Kleana provides superior risk transfer to the ratepayers of BC Hydro

1. Kleana is able to accept all development risk, financing risk, construction risk and operational risk;
2. Kleana has the support of the First Nations. This is in contrast to the opposition of local First Nations against Site C;
3. Project cost overruns will be Kleana's responsibility – this was highlighted by the Chairman:

   "*... if an IPP outfit, for example, is undertaking a project and they overrun; presumably, they eat the cost or the project never occurs. In the case of Hydro, if you were undertaking the same project, and you overran, the ratepayers would pay the cost.*" (Page 136-137 of Q&A Transcript)
4. Risk of sunk costs are Kleana's responsibility – we understand that the sunk costs for Site C are now approaching $500 million;

Kleana benefits from economies of scale but can still be combined with the energy from many wind and small run of river projects to equal the 1100 MW and 5100 GWh of Site C. These projects can "*be approved and built in smaller increments at a pace that closely matches demand growth. As increments, they are a flexible tool whose size and pace can be ramped up or down.*" (Page 4 of CEAR 2479)

<u>KLEANA'S FOOTPRINT VS SITE C'S FOOTPRINT</u>

The footprint of Kleana includes a flooded area of 40 hectares. The comparison we provided in our Presentation with Site C was for this critical impact.

The impacted land because of all our project structures is 250 hectares.

Recognizing that a small portion of our proposed transmission line is a water crossing to Vancouver Island, even including the entire land area of the transmission line right of way, without regard to absence of structures on the ground, Kleana's footprint is still only about 1100 hectares. We understand that Site C will flood over 9100 hectares. Therefore, even with the generous assumption that a transmission right of way bisecting a valley is equivalent to flooding a river valley, the footprint of Kleana is only a fraction of the area the Site C is flooding. However if one includes the footprint of the Site C structures and right of ways the footprint of Site C would be significantly larger than 9100 hectares. Perhaps an assumption of 10000 hectares is reasonable in this case. Such footprint can also be analyzed on the basis of Energy Intensity (GWh per Hectare):

	Site C	**Kleana**
Energy:	5100 GWh	2450 GWh
Land Footprint:	9100 -10000Hectare	1100 Hectare
Energy Intensity (GWH per Hectare):	0.56-0.51 GWH per Hectare	2.22 GWh per Hectare

Kleana's Energy Intensity is four times that of Site C.

CONCLUSION

We would like to re-state that Kleana is not a typical run of river project. Kleana should not be dismissed as a compliment or a partial alternative to Site C and unlike other projects BC Hydro has a current obligation to negotiate an EPA.

Kleana can provide 48% of the energy of Site C: 2450 GWh vs 5100 GWh at a fraction of the impacted land of Site C.

If 5,100 GWh of energy is needed, then Kleana with other projects can deliver on a cost effective basis. If 1,100 MW of capacity is needed Kleana with Rev6, GMS and SCGT, can deliver on a cost effective basis.

Kleana offers far lower risk to ratepayers at a far lower cost.

Respectfully submitted,

KLEANA POWER CORPORATION

Alexander Eunall

"Appendix 3"

PHILIP K. BARTON
LAW CORPORATION

STEVE DAVIS & ASSOCIATES
CONSULTING LTD.

February 4, 2014

BY E-MAIL (SiteCReview@ceaa-acee.gc.ca)

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Dear Sirs/Mesdames:

Re: Closing Comments

We are pleased to provide our Closing Comments on behalf of several independent private power (IPP) clients that are actively developing renewable energy projects.

We wish to clarify that all submissions to the Panel including these Closing Comments are only joint submissions of Philip K. Barton Law Corporation and Steve Davis & Associates Consulting Ltd. on behalf of our IPP clients. None of the comments, views or opinions expressed in any submissions were that of the law firm to which Philip K. Barton Law Corporation is an independent contractor, including the following:

1. Written Submission on November 25, 2013 (CEAR #1877);
2. Oral Submission on December 10, 2013 (CEAR #2093);
3. Letter on December 18, 2013 (CEAR #2222);
4. Part 1 Questions on January 15, 2014 (CEAR #2479); and
5. Part 2 Questions on January 21, 2014 (CEAR #2626).

We request that our registration be amended to reflect that all of the above submissions, including these Closing Comments, are from Philip K. Barton Law Corporation and Steve Davis & Associates Consulting Ltd.

We apologize if any confusion has resulted from the above submissions.

Respectfully submitted,

PHILIP K. BARTON
LAW CORPORATION

[signed]

Philip K. Barton

STEVE DAVIS & ASSOCIATES
CONSULTING LTD.

[signed]

Steve Davis

CLOSING COMMENTS

ON

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

ENVIRONMENTAL IMPACT STATEMENT

APPLICATION FOR THE

SITE C PROJECT

SUBMITTED TO THE

JOINT FEDERAL-PROVINCIAL REVIEW PANEL

BY

PHILIP K. BARTON LAW CORP. and STEVE DAVIS & ASSOCIATES LTD.

FEBRUARY 3, 2014

TABLE OF CONTENTS

Executive Summary

The Closing Comments of Philip K. Barton Law Corporation and Steve Davis & Associates Consulting Ltd. (collectively "**Barton/Davis**") on BC Hydro's Environmental Impact Statement ("EIS") Application for its Site C project is focused on the issue of cost-effectiveness. We appreciate this opportunity to provide closing comments on behalf of several independent private power (IPP) clients that are actively developing renewable energy projects. These IPP projects have a much lower environmental impact than Site C. Such projects are more cost effective than Site C.

We understand that BC Hydro's fundamental premise for requesting approval of Site C is that the significant adverse impacts are justified because Site C is claimed to be cost effective compared to other alternative projects.

The Minister of Energy and Mines appeared to echo this premise in the Vancouver Sun on December 7, 2013, stating: *"Governments make decisions on balance, and the balance in this case leads us to think this is the best available source of a large amount of electricity, and that justifies the environmental impact."*

Along the same vein, on January 23, 2014, the Chairman of Joint Review Panel said to BC Hydro: *"Another way of looking at is it that you would be charging those folks $630 million to avoid the environmental consequences of Site C. … But what I am getting at here is that there is a quantifiable trade-off here."*[1]

To which BC Hydro responded: *"Yes. When we looked at this, we've talked about the portfolio analysis before, there's a financial benefit of proceeding with this project. When we look at the environmental impacts, all projects have impacts. And so what you're looking at, and we did, to address this, we used the environmental attributes that we've talked about previously … But we believe on balance that when you look at the financial benefits, the economic benefits, and a little bit of a mix on the environmental attributes, we believe this is the preferred project."*

However, this document will show that there are many other attractive generation projects in B.C. that are more cost-effective than Site C and that have much less environmental impact.

In BC Hydro's EIS submissions, the main reasons that Site C appears to be cost effective is because of discriminatory assumptions for cost of capital, project life and the omission or under-estimation of significant costs. BC Hydro applies a weighted average cost of capital (WACC) of 7% to Independent Power Projects (IPPs) but a WACC of only 5% to Site C. BC Hydro calculates the cost of IPPs over 40 years, but uses 70 years for Site C. These two assumptions alone decrease the apparent cost of Site C by 28%. This is illustrated below:

WACC	**SITE C** **Adjusted Unit Energy Cost:** *(source)*	**CLEAN+THERMAL** **Adjusted Unit Energy Cost** *(source)*
5%	$94 *(Evidentiary Update)*	
6%	$110 *(Technical Memo)*	**UNKNOWN...** **$110 - 115???**
7%		$130 *(Evidentiary Update)*
8%		$155 *(Technical Memo)*

"**Evidentiary Update**" means BCH's *Evidentiary Update* dated September 13, 2013 (CEAR #1574)
"**Technical Memo**" means BCH's *Technical Memo – Alternatives to the Project* dated June 4, 2013 (CEAR #1458)

[1] Pages 101 – 103 of Transcript

BC Hydro's estimate of $7.9 billion appears to omit or underestimate several items. We estimate that Site C will cost at least $10 billion. Based on the cost increases of 21 previous large BC Hydro projects filed at BC Utilities Commission proceedings, a project contingency of $1.1 billion should be added. A cost of $127 million for transmission system improvements downstream of the Point of Interconnection appears to be missing. We found no evidence of the inclusion of equity cost during construction or First Nations Accommodation cost, which we estimate to be $678 million and $395 million, respectively. Adding those four items would increase the total capital costs (Capex) to $10.3 billion.

BC Hydro shows Site C's Unit Energy Cost (UEC) to be $95 assuming WACC of 5%, Project Life of 70 years and Capex of $7.9 billion. Its Adjusted UEC (AUEC) is $16 more at $110 (BC Hydro's *Technical Memo* dated June 4, 2013).

However, Site C's UEC increases to $143 with a Capex of $10.3 Billion, WACC of 7% and Project Life of 40 years. Adding the above $16 yields an AUEC of $159.

Three Alternative Portfolios are described in this document. Each Portfolio of projects will produce 5100 GWh and 1100 MW – equal to Site C. The AUEC for each of the projects in the Alternative Portfolio are BC Hydro data and are based on WACC @ 7% and Project Life @ 40 years. The only exception with using BC Hydro data was the Kleana project: its UEC and AUEC were calculated based on data presented in the Hearing by Kleana Power Corp., and formulas described in BC Hydro IR #27.

The following table compares six portfolios. The first three are Site C, before and after our suggested financial and capital cost adjustments. The last three are Alternative Portfolios that we have assembled.

Portfolio Name	***Site C***	***Site C***	***Site C***	***Alternative Portfolio #1***	***Alternative Portfolio #2A***	***Alternative Portfolio #3***
Source of Data or Description of Portfolio or Scenario	BC Hydro June 4 Tech Memo	BC Hydro June 4 with Adjusted Financial Asumptions	Adjusted Capex and Financial Assumptions	Geothermal @ 320 MW	Kleana (Firm Energy)	Six Resources
Source of Capacity	Site C	Site C	Site C	Geothermal, GMS, Rev6, MSW	Kleana, GMS, Rev6, MSW	Kleana, Geothermal GMS, Rev6, MSW
Source of Energy	Site C	Site C	Site C	Geothermal, Rev6, Wind, MSW	Kleana, Rev6, Wind, MSW, SCGT	Kleana, Rev6, Geothermal, Run of River, Wind, MSW
WACC	6%	7%	7%	7%	7%	7%
Evaluation Period	70	40	40	40	40	40
Capital Cost (billion)	7.9	7.9	10.3	-	-	-
Unit Energy Cost (2013 $/MWh)	94	115	143	-	-	-
Adjusted Unit Energy Cost (2013 $/MWh)	**110**	**131**	**159**	**120**	**116**	**109**

MSW = Municipal Solid Waste. SCGT = Simple Cycle Gas Turbine

Rev6 = Revelstoke Unit#6. GMS = Gordon M Shrum Units #1 - 5

- BC Hydro did not provide Capex or UECs for individual IPP projects

The table shows that Site C's AUEC increases 19% when its WACC and Project Evaluation Period are the same as the Alternative Portfolios, at 7% and 40 years respectively. Its new AUEC of $131 would be higher than all Alternatives.

If Site C's Capital costs are $10.3 billion and the WACC and Project Evaluation Period are 7% and 40 years, then its AUEC would be $159. The most cost-effective Portfolio is Alternative #3 with an AUEC of $109.

The dozen projects in the Alternative Portfolio have a much smaller environmental impact than Site C. They are located in several regions on B.C. They are driven by 6 different fuels/technologies; wind, run of river, storage hydro, biomass, MSW, and natural gas. They range in size from 24 MW to 565 MW.

The pace of the building of these dozen projects can be matched to electricity demand growth. That reduces the risk to electricity ratepayers of over, or under building generation. That is a major risk with the much larger and singular Site C project.

The incremental implementation of smaller projects provides great flexibility. It also allows the procurement of the best technology or best fuel as different technologies evolve and as the price of fuels change.

In summary: IPPs are cost effective. Alternative Portfolio #3 has an AUEC that is 17% less than Site C after leveling the playing field for WACC and Project Life. In addition, Alternative Portfolio #3 has an AUEC which is 31% less than Site C after **both** leveling the playing field **and** including the higher potential capital costs.

Our pricing analysis was based on data provided by BC Hydro, with the exception of Kleana. And we included several conservative assumptions in our estimates for additions to Site C capital costs. Many new alternative portfolios can be created from the hundreds of IPP projects identified – likely with even lower UECs.

Proving cost-effectiveness is key. Site C has not proved that it is not cost effective. Therefore, the significant adverse impacts are not justified.

1. Weighted Average Cost of Capital

In BC Hydro's EIS submissions the main reason that Site C appears to be cost effective is because of discriminatory assumptions for weighted cost of capital (WACC). This is illustrated below:

WEIGHTED AVERAGE COST OF CAPITAL (WACC)	**SITE C Adjusted Unit Energy Cost:** *(source)*	**CLEAN+THERMAL Adjusted Unit Energy Cost** *(source)*
5%	$94 *(Evidentiary Update)*	
6%	$110 *(Technical Memo)*	**UNKNOWN... $110 - 115???**
7%		$130 *(Evidentiary Update)*
8%		$155 *(Technical Memo)*

"**Evidentiary Update**" means BC Hydro's *Evidentiary Update* dated September 13, 2013 (CEAR #1574)
"**Technical Memo**" means BC Hydro's *Technical Memo – Alternatives to the Project* dated June 4, 2013 (CEAR #1458)

A 1% change in WACC results in a change of approximately $15 in AUEC, a 2% change in WACC roughly doubles that change. So when BC Hydro compares Site C AUEC vs Alternative Portfolios and uses a 2% WACC differential, Site C starts with a roughly $30 advantage – even before looking into the project's actual costs.

If the 2% WACC differential is removed, Site C's AUEC increases substantially. When potential additional costs are added to Site C, its initial appearance of cost-effectiveness disappears.

WACC is driven by project risk not proponent type

The WACC of a project should reflect the risk of the project. The risk of a project is the actual risk of the project. The risk of a project does not change depending on who owns it.

Using a lower WACC to reduce the cost of a project because it is owned by one party vs another ignores the real risks of the project. For example, would a wind project owned by BC Hydro reduce its risk? Using different WACCs when comparing projects distorts the actual risks of the projects. Using a lower WACC for Site C artificially reduces the risk of Site C.

Despite our numerous requests, BC Hydro has never used an identical WACC in any comparison between Site C and Alternatives. We have repeated this concern many times:

1. Page 5 of our Written Submission dated November 25, 2013:

   "*Using a lower WACC to reduce the cost of a project because it is owned by one party vs another ignores the real risks of the project*." (CEAR #1877)

2. Slide 14 of our Oral Presentation dated December 10, 2013:

   "*WACC: BC Hydro imposes lower Weighted Average Cost of Capital*" (CEAR #2093)

3. Page 2 of our letter dated December 18, 2013:

   "*…we cannot understand why BC Hydro believes that the cost of financing an IPP project is 40% higher than the cost of financing Site C, a mega-project with a significant risk profile. This treatment by BC Hydro distorts the Adjusted Unit Energy Costs contained in both the Technical Memo and the Evidentiary Update. Such distortion favours Site C at the expense of alternatives.*

   … we recommend that … BC Hydro remove the distortions caused by WACC by submitting alternative portfolios that are based on an identical WACC. We recommend using a conservative WACC of 6% for both Site C and all IPPs because this would reflect a prudent contingency for the capital markets risk of a mega-project representing the next 80 years: 10 years of construction and 70 years of operation." (CEAR # 2222)

4. Page 13 and 14 of our Questions dated January 15, 2014:

   "*BC Hydro's assumption of a 5% WACC does not reflect risk nor the likelihood of interest rate fluctuations during the 80 year timeframe. In contrast, IPP projects accept all financing risk during the approximate 5 years to in-service and thereafter for the life of the contract, potentially up to a 40 year period.*

   From the BC Hydro ratepayer's point of view, this is an important difference in the allocation of risk: whether interest rate fluctuations impact directly to the ratepayers (Site C) or whether those fluctuations are isolated to IPPs? To compensate for this severely increased adverse risk over an 80 year period, Site C needs a prudent contingency allowance included in its WACC. (CEAR #2479)

We were pleased to hear the Chairman state on January 23, 2014 (page 136 of Transcript):

> *"THE CHAIRMAN: … without accounting for the nature of the proponent and so on and so forth, but <u>you would account for risks inherent to the project, not inherent the proponent</u> ...*
> *REIMANN: Well -- and -- and that was the discussion that we had with the BC Utilities Commission. And what they suggested was if there was an advantage in financing a project, that was to the benefit of ratepayers, that we should recognize that. So that's where we've landed.*
> *THE CHAIRMAN: Well, if that's what they wound up saying, then I think they are ignoring the assignment of project risk. <u>And I think that that's an improper decision</u>…"* (emphasis added)

We conclude that an analysis of alternatives should use the same cost of capital without regard to who is the proponent.

BC Hydro did not provide AUECs for the Clean+Thermal Portfolio at 6%. To create a level playing field, we have converted Site C's AUEC to a 7% WACC – the same as IPPs. Therefore, in our subsequent analysis we use a WACC of 7% for both Site C and all IPPs.

CD Howe Commentary also recommends using same discount rates

The Panel provided BC Hydro with a paper relating to WACC, government guarantees and discount rates published by the C.D. Howe Institute "*Commentary on Valuation of Public Projects: Risk, Cost of Financing, Cost of Capital*" in September 2013 (the "**Commentary**").[2]

The Commentary identifies four common mistakes on Page 2:

> *"Four mistakes are commonly made when evaluating public and private investment…*
>
> 1. *… using different discount rates, depending on whether the project is carried out by the public sector (lower rate) or by the private sector (higher rate)…,*
> 2. *Using a cost of capital for the business … rather than for a specific cost of capital for each project, properly assessed against the risk of that particular project …*
> 3. *Using a single cost of capital or discount rate for a project that is dependent upon several factors or sources of risk.*
> 4. *Using a discounting method such as NPV that fails to quantify the value of managerial flexibility in the development, implementation and/or continuation of a project in a changing and volatile environment."*

<u>Barton/Davis comparisons will use equal discount rate</u>

To avoid mistakes #1 and #2, when we compare the UECs of Site C to Alternative Portfolios, we will use the same discount rate. Both Site C and IPPs will assume a discount rate of 7%.

CD Howe Commentary on the value of flexibility

Mistake #4 supports the point we made in our Page 3-5 of Part 1 Questions (CEAR 2479). It asks:

> IN RESPONSE TO FUTURE CHANGES, WHY HAS BC HYDRO ASCRIBED ZERO VALUE TO THE FLEXIBILITY OF IMPLEMENTING A DOZEN INDIVIDUAL PROJECTS VS. THE SINGLE ALL OR NOTHING MEGA-PROJECT SITE C?

BC Hydro's Table 5 "Benefit of the Project: Updated Sensitivity Analysis Summary"[3], confirms that point numerically. It shows the PV for the Clean and Clean+Thermal Portfolios are less than Site C under several different future scenarios.

The incremental development aspect of the IPP portfolios gives flexibility to pick cheaper sources of generation as they become available. For instance; if wind costs continue to drop, geothermal becomes viable, LNG requires nearby generation, a new intertie with Alaska allows access to new low cost IPPs, or MW-scale storage arrives and allows wind to be firmed economically, etc.

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[2] Question 27 of Round 2 of the Information requests from Panel – response by BC Hydro was on October 4, 2013

[3] Page 12, Information Request #77, BC Hydro, October 31, 2013. CEAR 1645

Fortis uses same financial assumptions to evaluate resource options.

FortisBC avoids discrimination against IPP projects on the basis of cost of capital during its evaluation of resource options. Appendix C - Resource Option Report of the 2012 FortisBC Resource Plan states:

> *"The financial assumptions used to calculate the cost metrics have been standardized to ensure that all resource options are evaluated consistently, regardless of the return expectations and cost of capital that might be applicable to a given project."*

BC Hydro used the same WACC to compare Site C to IPPs in 2006

BC Hydro formerly applied a non-discriminatory policy for evaluating resource options. The 2005 Resource Options Report of BC Hydro's 2006 Integrated Electricity Plan states:

> ***"4.2 Comparability and Simplified Analysis Issues*** *BC Hydro is both the purchaser of resources via IPP contracts and the owner of certain resources (primarily hydro projects and transmission projects via BCTC). BC Hydro is striving to ensure that the methods of representing and evaluating resource options are transparent and non-discriminatory. ... For these reasons, the following issues have been identified and a recommended approach is described:*
>
> ...
>
> ***4.2.2 BC Hydro versus IPP Cost of Capital*** *BC Hydro has access to lower-cost pre-tax debt than IPPs because it has access to government-secured debt. IPPs can deduct interest expenses from earnings. As well, some IPPs may have stronger balance sheets than others and therefore have some advantages over other IPPs. However, such financing advantages do not alter the investment risk inherent in the project. Therefore, it is recommended that the same discount rate be applied to all resource options regardless of who develops them.*"

WACC for Site C should be higher to reflect longer time to In-Service Date

Previous experience with sharply rising interest rates should result in a WACC for Site C that is higher (not lower) to reflect the greater capital markets risk of a project that has such a long horizon - extending over 80 years: 10 years of construction and 70 years of operation.

BC Hydro's assumption of a 5% WACC does not reflect risk nor the likelihood of interest rate fluctuations during the 80 year timeframe. In contrast, IPP projects accept all financing risk during the approximate 5 years to in-service and thereafter for the life of the contract, potentially up to a 40 year period.

From the BC Hydro ratepayer's point of view, this is an important difference in the allocation of risk: whether interest rate fluctuations impact directly to the ratepayers (via Site C) or whether those fluctuations are isolated to IPP shareholders. To compensate for this severely increased adverse risk over an 80 year period, Site C needs a prudent contingency allowance included in its WACC.

Further, BC Hydro's portfolio analysis indicates that a WACC differential of only 1% reduces the Present Value Cost of the Clean+Thermal Portfolio to within only $20 million of Site C. A present value cost differential of $20 million does not justify the significant adverse impacts of a mega-project of at least $7.9 Billion.[4]

Removing the distortions of the WACC-differential is essential to assess whether Site C is, in fact, cost-effective.

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[4] Page 12 of BC Hydro's October 31st response to JRP Information Request 77-A (CEAR #1645)

Choice of WACC has a major impact on PV.

The following table, produced by BC Hydro in the October 31, 2013 response to IR 77-A (CEAR #1645), shows that reducing the WACC Differential from 2% to 1% removes $130 million from the PV Cost of Clean+Thermal – a decrease from $150 million (Base Case) to $20 million (WACC Differential = 1%).

Table 5 – Benefit of the Project: Updated Sensitivity Analysis Summary

Difference in PV Cost (Portfolio without Site C minus with Site C) ($F2013 million)	**Clean Generation Portfolios**		**Clean + Thermal Generation Portfolios**	
	F2024	F2026	F2024	F2026
Base Case (Mid Gap, Mid-Market Price [Scenario 1], WACC Differential = 2%, Wind Integration Cost = $10/MWh	630	880	150	390
Large Gap	Note 1	Note 1	2,260	Note 1
Small Gap	(1,040)	(705)	(1,280)	(907)
High Market Price (Scenario 3)	830	1,028	470	656
Low Market Price (Scenario 2)	450	755	(90)	217
0.62 USD/CAD Exchange Rate	950	Note 1	570	Note 1
1.085 USD/CAD Exchange Rate	570	Note 1	90	Note 1
Site C Capital Cost +10%, alternatives held constant	360	650	(120)	170
Site C Capital Cost +15%, alternatives held constant	250	560	(230)	70
Site C Capital Cost +30%, alternatives held constant	(60)	270	(580)	(220)
Site C and Alternative Resource Options Capital Cost +30%	600	950	(100)	300
WACC Differential = 1%	420	672	20	233
Wind Integration Cost ($15/MWh)	720	Note 1	222	Note 1
Wind Integration Cost ($5/MWh)	530	Note 1	92	Note 1
Compound Low Scenario (Small Gap, Low Market Price, 10% Site C Capital Cost Increase)	Note 1	Note 1	(2,000)	(1,600)
Compound High Scenario (Large Gap, High Market Price, 10% Site C Capital Cost Decrease)	Note 1	Note 1	2,610	Note 1

We estimate that reducing the WACC differential to 0% would remove a total of $260 million from the PV Cost of Clean+Thermal. The revised PV Cost for Clean+Thermal would then be negative $110 million. Therefore, without any difference in WACC, the Clean+Thermal would have a lower PV Cost.

Site C has $500 million head start.

Our calculations have determined that sunk costs must currently exceed $400 million to result in an AUEC of $5 per MWh for each MWh of the 70 year period of 2024 to 2094. We also understand that the sunk costs for Site C are expected to reach $500 million by the end of F2014 (March 31, 2014).[5]

We believe these sunk costs of Site C have been excluded from BC Hydro's analysis of Present Value Cost Difference of Site C vs Alternatives. Therefore, such inclusion will reduce the PV Cost differential by a corresponding $500 million in each amount in the summary sensitivity table on the previous page.

Reducing each of the above PV Cost differentials by $500 million, would result in the majority of sensitivities showing alternatives with a lower PV Cost than Site C because the majority of the PV Cost differentials would be negative.

This calculation would demonstrate that if the identical analysis occurred several years ago, prior to spending $500 million on Site C, that Site C would have shown a greater PV Cost than alternatives. In other words, Site C requires a "head-start" of $500 million over IPP alternatives because, without such a "head-start", Site C is not cost effective.

The huge level of costs already sunk into Site C and the fact that it can swing the PV Cost calculations from lower than alternatives to higher than alternatives shows the hazard of choosing a single huge project compared to the flexibility of choosing smaller projects at a flexible pace.

WACC for Site C should be higher to reflect size and riskiness

Because of its size and riskiness, this multi-billion dollar mega-project should actually require a higher rate of return than BC Hydro's normal lines of business.

Without unlimited recourse to taxpayers, instead of a lower cost of capital, Site C would require a higher cost of debt and also a higher proportion of equity than Hydro's routine business. That means that the taxpayers are being asked to subsidize the ratepayers by backstopping this mega-project risk without being offered the compensation of higher returns.

A single mega-project like Site C is significantly more risky than a diversified portfolio of smaller projects, which are bid and built by a number of competing private developers, each bearing their own separate business and financial risk. This is reinforced because the ratepayers are being financially protected from the risks of the smaller projects, but are totally exposed to the risks of Site C.

The size and riskiness of this mega-project is of such a scale that it could actually alter the risk profile of the corporation as a whole. This could have a cascading effect on the cost of all projects in the future. Therefore, it is arguable that the Site C mega-project should have a higher cost of capital, and also a higher proportion of equity than BC Hydro's routine lines of business.

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[5] See: Amended F12/F14 Revenue Requirement Application, Amended Appendix A, page 12, Schedule 2.2

2. Costs missing or under-represented in Site C

BC Hydro based its Unit Energy Costs on its capital cost estimate of $7.9 billion.

We believe that there are several missing or under-represented costs, as reflected in the table below.

Missing or under-estimated item	*COST ESTIMATE*($ billion)	*Source*
Original Capital Cost	7.900	BC Hydro Technical Memo - Project Costs June 4, 2013)
Potential Additional Costs		
Project Overrun Contingency	1.185	15% - based on Overrun Analysis of 21 Large BC Hydro Projects updated from Question #9 of Barton/Davis Letter of January 15, 2014
Transmission improvements after POI	0.127	Analysis submitted with Page 5 of Barton/Davis Letter of January 15, 2014 (CEAR 2626)
Equity Cost During Construction	0.678	Slide #15 of Barton/Davis Presentation on Dec. 10, 2013. Page 4 of CEBC Undertaking 12 on Dec. 17, 2013
First Nations Accommodation	0.395	5% - based on overun on BCH's NTL project as explained in Amended Appendix 1 of Amended RRA F12-14
Total Potential Cost Adders	**2.390**	
New Potential Capital Cost Total	**10.290**	

Each of the above cost items will be described in this chapter. Plus several additional cost items that we believe have also been overlooked, but we have not quantified.

Project Overrun Contingency

BC Hydro based its Unit Energy Costs on its capital cost estimate of $7.9 billion. That number is too low.

Average cost increase on large BC Hydro projects has been 16%

Our detailed analysis of 21 recent large capital projects by BC Hydro that are greater than $50 million shows an average cost overrun of 16%. These are the same 21 projects included in the BC Hydro Reconciliation dated January 23, 2014 (CEAR #2714) with the exception of the Smart Meter Initiative (which should not be included because has no relation to complex construction projects).

Analysis of the BC Hydro Cost Overrun Reconciliation Presented at Closing Hearing on January 23, 2014 (CEAR #2714)

Project	BCUC Order	BCUC Order Approved Cost	Final Cost per BCH/BCTC Revenue Requirement F12/F14 - Appendix I Amended	Year	Project Cost Differential	Comments
Generation Projects - Completed						
Aberfeldie	C-02-07	$64,000,000	$95,000,000	F12-F14	48%	See Note 1
Revelstoke Unit 5	C-08-07	$280,000,000	$250,000,000	F12-F14	-11%	Agreed With BCH
Fort Nelson Resource Smart	G-75-09	$140,100,000	$165,200,000	F12-F14	18%	Agreed With BCH
Coquitlam Dam Seismic Upgrade	G-143-06	$58,000,000	$64,900,000	???	12%	See Note 2
GMS 1-4 Stator Replacement	G-143-06	$83,000,000	$81,400,000	F12-F14	-2%	See Note 3
PCN G1-G4 Stators	G-143-06	$67,000,000	$72,500,000	F12-F14	8%	See Note 4
Mica G1-G4 Stator Replacement	G-143-06	$78,000,000	$86,200,000	F12-F14	11%	See Note 5
Generation Projects - Implementation						
GMS Unit 1-5 Replacement	G-01-10	$262,000,000	$246,300,000	F12-F14	-6%	See Note 6
Mica Gas Insulated Switchgear	G-38-10	$180,600,000	$190,400,000	F12-F14	5%	See Note 7
Stave Falls Spillway Gates	G-81-10	$61,500,000	$66,000,000	F12-F14	7%	See Note 8
Mica Units 5&6	Exempt by CEA	$627,000,000	$675,000,000	F12-F14	8%	See Note 9
HLK Spillway Gates	G-177-10	$90,200,000	$102,500,000	F12-F14	14%	Agreed With BCH
Ruskin Dam and Power House Upgr	G-5-12	$640,600,000	$750,000,000	F12-F14	17%	See Note 10
Transmission Projects - Completed						
VTR	C-04-06	$249,000,000	$308,000,000	F12-F14	24%	Agreed With BCH
Central Vancouver Island	C-06-08	$91,600,000	$62,750,000	F12-F14	-31%	Agreed With BCH
Columbia Valley Transmission	C-05-10	$154,100,000	$133,000,000	F12-F14	-14%	See Note 11
Transmission Projects - Implementation						
Interior Lower Mainland	C-04-08	$602,000,000	$752,000,000	F12-F14	25%	See Note 12
Vancouver City Central Transmissio	C-03-10	$189,000,000	$174,500,000	F12-F14	-8%	See Note 13
Northwest Transmission Line	Exempt by CEA	$404,000,000	$736,000,000		82%	See Note 14
Dawson Creek/Chetwynd Area Transmission (DCAT)	C-5-13	$222,300,000	$296,400,000	F12-F14	33%	See Note 15
Seymour Arm Series Capacitor	G-87-09	$65,300,000	$53,000,000	F12-F14	-19%	See Note 16
Smart Meter Intiative	Exempt by CEA	N/A	N/A			See Note 17
TOTALS		**$4,609,300,000**	**$5,361,050,000**		**16%**	

CEA means Clean Energy Act

This 16% amount is much larger than the amount shown in BC Hydro's December 23, 2013 Rebuttal which states:

> *"BC Hydro also reviewed a total of 774 self-build projects (over $1 million) completed in the last 5 years. The result is a cost of $11 million over the original expected of $3.3 billion, or within 0.34% of original expected amount."*

BC Hydro has chosen a tremendous number of projects, including many small projects. And they have evaluated them from different starting points, described as "original expected amount".

Barton/Davis letter of January 15, 2014 contained a table on page 19 which calculated the average cost overrun for 42 major projects between the (CPCN) Approved Cost and the Final Cost in accordance with BC Hydro's Revenue Requirement Application (RRA). With our new table on the previous page, our analysis is using the same projects as BC Hydro's Reconciliation.

It is helpful that BC Hydro has confirmed that the Site C cost estimate is a 50 percentile estimate (P50):

> "*Our estimating philosophy for the bulk of our portfolio -- and Mr. Savidant can talk about how it's applied to Site C, but our estimating philosophy is to use this 50 percentile concept. So we estimate projects at a level such that 50 percent of them should come in under and 50 percent should come in over.*"[6]

Our analysis also focuses on the P50 cost estimate which is consistent with Certificate of Public Convenience and Necessity (CPCN) approval by the BC Utilities Commission. Therefore, our analysis of 21 large BC Hydro projects is consistent with the approach used for Site C. The Reconciliation provided by BC Hydro on January 23, 2014 (CEAR #2714) is based on the "*First Implementation Estimate*" (Page 138 of Transcript from January 23, 2014) – an estimate which becomes apparent much later in the project's life-cycle.

Reasons to expect construction cost overruns

<u>Estimate is old. New pressures driving cost increases</u>

The $7.9 billion cost estimate was announced in May 2011 and has not been updated.

There is now expected to be a construction boom in excess of $100 billion in Northern B.C. including bitumen pipelines, gas pipelines, liquefied natural gas export facilities and new mines.

The construction window of Site C will compete with critical shortages of labour, materials, equipment and contractors. This may be similar to the pre-2008 oil sands development boom and associated spiralling construction costs.

Significant cost overruns have occurred on one of BC Hydro's recent northern projects, the Northwest Transmission Line. Costs increased from $404 million to $736 million between 2009 and 2013 – an increase of over 80% even without the competition of a super-heated construction economy.

[6] Page 138 of Transcript from January 23, 2014.

Manitoba Experience relevant to B.C.

Manitoba Hydro experienced a 60% cost overrun in 2012 when the $900 million original budget estimate for the 200 MW Wuswatkim Dam resulted in a final cost of $1.69 Billion.[7] This large overrun could have partially resulted from a 20 year experience gap since construction by Manitoba Hydro of the last previous large dam project: the 1340 MW Limestone Dam in 1992.

We note that 40 years will have elapsed between the 2024 In-Service Date of Site C and when BC Hydro last commissioned a new large dam: the 1984 commissioning of the Revelstoke Canyon Dam.

Equity Cost During Construction

There is nothing in the record that indicates that BC Hydro includes charging for equity during construction in their $7.9 billion cost. Their capital costs only refer to Interest During Construction (IDC).

Barton/Davis raised the subject of possible omission of equity costs during construction (ECDC) point in our Oral Presentation on December 10, 2013 (CEAR #2093), and submitted a question on January 21, 2014[8] asking if $678 million of ECDC had been excluded.

The Clean Energy Association of British Columbia (CEBC) raised this point on December 17, 2013 in its Undertaking #12 as follows:

> "*Finally, it is not clear whether BC Hydro has included equity costs during construction in its Site C analysis. The only reference in the evidence appears to be to interest during construction. If the equity cost during construction has been omitted, it is very material given Site C's long construction period and high capital cost.*"

It appears that BC Hydro did not discuss ECDC in their Dec 23rd rebuttal to CEBC.

We estimate the ECDC to be at least $678 million.

While an estimate of $1550 million for Interest During Construction (IDC) has been included in the $7.9 Billion estimate, we cannot identify any estimate for the equity cost during construction (ECDC). It is typical utility practice for the aggregate of IDC and ECDC to be labelled: *Allowance for Funds Used During Construction* (AFUDC). We saw nothing in the submission documents about AFUDC.

We estimate the ECDC to be significant for such a long construction period. A simple calculation results:

ECDC = IDC * (WACC / Interest Rate) - IDC
ECDC = $1,550 * (6.9% / 4.8%) - $1,550
ECDC = $2,228 million - $1,550 million
ECDC = $678 million

[7] See: http://www.thetelegram.com/Opinion/Columns/2012-08-07/article-3047093/Cost-overruns,-by-nature,-are-unforeseen/1

[8] January 21, 2014 Barton/Davis letter (Page 2-3 of CEAR 2626).

The project cost estimate for Site C is reproduced from the *Technical Memo – Project Costs* (June 4, 2013):

Table 1 Project cost estimate breakdown

	($ million)
Dam and Associated Structures	**1,790**
Earthfill Dam	
Approach Channels & RCC Buttress	
Spillway, Intakes & Penstock	
Left (North) Bank Stabilization	
Cofferdams, Dikes, Diversion Tunnels	
Power Facilities	**990**
Powerhouse & Switchgear Building	
Stations and Transmission	
Offsite Works	**530**
Highway 29 Relocation, Access Roads, Clearing, Land & Rights	
Construction Management & Services	**515**
Worker Accommodation	
Construction Management & Construction Services	
Total Direct Costs	**3,825**
Indirect Costs	**1,005**
Development Costs, including sunk costs	
Regulatory Costs	
Construction Insurance	
Management & Engineering	
Mitigation & Compensation	
Contingency	**730**
Total Construction and Development Costs (2010 real dollars)	**5,560**
Inflation	**790**
Interest During Construction	**1,550**
Total Construction and Development Costs (nominal)	**7,900**

Transmission system improvements downstream of POI.

The cost estimate of $7.9 billion provided by BC Hydro in the original EIS and the September Evidentiary Update appears to only include transmission costs to the Point of Interconnection (POI). It does not include any system improvements downstream of the POI.

IPP's, such as those analyzed in the Block and Portfolio analysis, are subjected to what BC Hydro calls the Standard Generator Interconnection Process (SGIP). The SGIP process identifies system improvements and costs downstream of the POI to facilitate the integration of the IPP project to the BCH grid in the region. These system costs are back charged to IPP's and/or applied to IPP's bid price in Clean Power Call evaluations. Accordingly, Resource Option UEC's for IPP's include system improvement costs, whereas BC Hydro has not.

The SGIP process costs approximately $270,000 and takes approximately 10 to 15 months to complete. The cost estimate provided is ± 10% to ± 20% depending on IPP's requirement for cost certainty and time frame (more accurate cost estimate takes longer).

BC Hydro has identified at least $127M of system upgrade costs pre Site C. It could potentially be up to $854M (or higher since the proposed upgrades do not include any wire upgrades such as an additional 500kV circuit from GMS to Kelly Lake). The actual cost for system upgrades would be identified through a SGIP type Facilities/System Impact study.

The 2013 IRP acknowledged that transmission upgrade/reinforcement was required from GMS to Kelly Lake by 2024 which is the In-Service date proposed for Site C. The 2013 IRP Section 9.2.8 states:

> "*The cost to complete further study work over the next five years is estimated to be $5.0 million. BC Hydro will have a total cost estimate with an accuracy range of +35 per cent/-15 per cent when the study work is completed. The transmission upgrades are planning level estimates and detailed analytical studies are required to finalize scope and cost.*"

In short, the SGIP process takes approximately 10-15 months and approximately $270,000 in costs and results in transmission upgrade cost with an accuracy of ± 10% to ± 20% for IPP projects that have transmission capital costs in the order $100 million. We have difficulty understanding why BC Hydro needs 5 years and $5 million to develop a cost estimate of +35 per cent/-15 per cent if they only have $62M to $127M in non-wire transmission upgrades. Five years and $5 million suggests a much more complex analysis and potentially much higher capital cost.

In our potential capital cost adjustments, we will assume a missing cost of $127 million, rather than the $854 million that is possibly overlooked.

First Nations Accommodation

The cost of First Nations Accommodation appears to be overlooked in BC Hydro's costing.

BC Hydro states that:

> *"The Project cost estimate of $7.9 billion (nominal dollars) contains cost allowances for mitigation, regulatory review, First Nation consultation, and public engagement. Implementation of the available resources would also entail mitigation, regulatory review, First Nation consultation, and public engagement costs (referred to as 'soft costs'), but it is not possible to precisely quantify such soft costs, as it is difficult to predict the outcome of consultation/engagement or to identify the costs of such processes or the costs of mitigation requirements that may be imposed following these processes, not least because different First Nations and stakeholders may have conflicting goals and requirements. Accordingly, while the available resource costs set out in Section 5.5.2 do not include such costs, BC Hydro has put a cost adder of 5% on available resource portfolios to reflect the fact that implementing any of the available resource options would trigger soft costs. Refer to Section 5.5.3 for greater detail."* [9] (emphasis added)

There is no mention of First Nations Accommodation. Such accommodation is much more costly than First Nations consultation.

The Treaty 8 First Nations also pointed to this potential omission on January 23, 2014:

> Based on these estimates, we are concerned that certain costs are not included in the estimate of indirect costs for Site C, that little money has been set aside for environmental mitigation and compensation, or that Aboriginal accommodation costs have not been included in the estimate. We have attached information for the BC Hydro Interior to Lower Mainland Transmission Project and the BC Hydro Northwest Transmission Line Project where BC Hydro did not include Aboriginal accommodation costs until after project approvals.

The cost overruns for the Northwest Transmission Line was substantial. Specifically the overrun was $332 million. BC Hydro's estimate provided to the Federal Government for federal funding was $404 million. That increased to $736 million by the date of the RRA. BC Hydro stated that the overages were the result from First Nations accommodation, costs arising from EAC requirements, legal costs arising from EAC and CPCN appeals.[10]

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[9] Section 5.5.1 of the EIS.
[10] CEAR #2682: Note 10, Appendix J of BC Hydro's F12/F14 Revenue Requirements Application.

BC Hydro adds a Soft Cost Adder to IPP UECs

The omission of FN Accomodation is in sharp contrast to the 5% soft cost adder which is imposed by BC Hydro on the UECs of all IPPs which is for both First Nations consultation and accommodation. Therefore, these same costs which are not included in BC Hydro's Site C estimate, are still included in the IPP resources in the Clean Block and Clean Block+Thermal Portfolios.

Capitalized Overhead Costs

There is nothing in the record that indicates that BC Hydro included capitalized overhead costs in their $7.9 billion estimate. Barton/Davis asked BC Hydro if it had included them in its January 15, 2014 letter.

Traditionally, BC Hydro has allocated corporate overhead costs of approximately 13 to 18% and capitalized them into its project costs. However, we cannot identify any explicit mention of allocated overhead charges in the project cost estimate.

Sunk Costs

The total Sunk Costs of Site C are expected to reach $500 million by March 31, 2014.

BC Hydro has included the Sunk Costs of Site C in the $7.9 billion capital cost estimate.

However, they have been excluded from BC Hydro's analysis of Present Value Cost Difference of Site C vs Alternative Portfolios. Accordingly they are addressed in Chapter 1 on WACC.

Insurance During Construction

Treaty 8 First Nations stated, on page 2 of their January 21, 2014 letter that; *"Consultants engaged by the T8FNs estimated that construction insurance cost could represent as much as 9% of Direct Construction costs."* Table 1 shows that Construction Insurance was "Not Provided" in the EIS.

Total of Potential Capital Cost Adders

The following table totals several Capex Adders:

	$ billion	Assumption
Original Capital Cost	7.900	
Potential Additional Costs		
Project Overrun Contingency	1.185	15% of Original Capital Cost $7.9 b*
Transmission improvements after POI	0.127	Lowest of $127 to $854 million
Equity Cost During Construction	0.678	$678 million
First Nations Accommodation	0.395	5% of Original Capital Cost $7.9 b
Total Potential Cost Adders	2.390	
New Potential Capital Cost Total	10.290	

* The 15% is on top of existing projects that included contingencies. That appears to be how BC Hydro typically does this kind of estimating. The 15% is slightly less than the 16% determined from analyzing past projects. This $10.29 billion does not including any additional costs for: Capitalized Overhead Charges or Insurance During Construction. We simply did not have enough information on them.

PV Impact of Unaccounted Costs

To illustrate the significant impact to PV Cost of the above unaccounted costs, we reproduce again the sensitivity summary prepared by BC Hydro in the October 31, 2013 response to IR 77-A (CEAR #1645):

Table 5 – Benefit of the Project: Updated Sensitivity Analysis Summary

Difference in PV Cost (Portfolio without Site C minus with Site C) ($F2013 million)	**Clean Generation Portfolios**		**Clean + Thermal Generation Portfolios**	
	F2024	F2026	F2024	F2026
Base Case (Mid Gap, Mid-Market Price [Scenario 1], WACC Differential = 2%, Wind Integration Cost = $10/MWh	630	880	150	390
Large Gap	Note 1	Note 1	2,260	Note 1
Small Gap	(1,040)	(705)	(1,280)	(907)
High Market Price (Scenario 3)	830	1,028	470	656
Low Market Price (Scenario 2)	450	755	(90)	217
0.62 USD/CAD Exchange Rate	950	Note 1	570	Note 1
1.085 USD/CAD Exchange Rate	570	Note 1	90	Note 1
Site C Capital Cost +10%, alternatives held constant	360	650	(120)	170
Site C Capital Cost +15%, alternatives held constant	250	560	(230)	70
Site C Capital Cost +30%, alternatives held constant	(60)	270	(580)	(220)
Site C and Alternative Resource Options Capital Cost +30%	600	950	(100)	300
WACC Differential = 1%	420	672	20	233
Wind Integration Cost ($15/MWh)	720	Note 1	222	Note 1
Wind Integration Cost ($5/MWh)	530	Note 1	92	Note 1
Compound Low Scenario (Small Gap, Low Market Price, 10% Site C Capital Cost Increase)	Note 1	Note 1	(2,000)	(1,600)
Compound High Scenario (Large Gap, High Market Price, 10% Site C Capital Cost Decrease)	Note 1	Note 1	2,610	Note 1

We focus below only on the Base Case:

Item	Clean Block		Clean + Thermal	
	F2024	F2026	F2024	F2026
Base Case	$630M	$880M	$150M	$390M
Less 0% WACC Differential	($260M)	($260M)	($260M)	($260M)
Less Sunk Costs	($500M)	($500M)	($500M)	($500M)
Less Additional Capex ($2.39B)	($2,397M)	($2,397M)	($2,397M)	($2,397M)
TOTAL	($2,527M)	($2,277)	($3,007)	($2,767)

Without any sensitivity adjustments, not even the Base Case is cost effective against either the Clean Block or Clean+Thermal. The PV reduction of the additional $2.39 billion capex of $2,397 was based on back calculation from the $2.39 Billion cost. The PV sensitivity provided in Table 5 is based on 15% of BC Hydro's Total Construction and Development cost of $5,560 Billion or $834 Million. This explains the difference.

3. Cost Effective Alternatives

Alternative Portfolios

The following table summarizes three of our Alternative Portfolios and their Unit Energy Costs.

Portfolio Name	***Alternative Portfolio #1***	***Alternative Portfolio #2A***	***Alternative Portfolio #3***
Source of Data or Description of Portfolio or Scenario	Geothermal @ 320 MW	Kleana (Firm Energy)	Six Resources
Source of Capacity	Geothermal, GMS, Rev6, MSW	Kleana, GMS, Rev6, MSW	Kleana, Geothermal GMS, Rev6, MSW
Source of Energy	Geothermal, Rev6, Wind, MSW	Kleana, Rev6, Wind, MSW, SCGT	Kleana, Rev6, Geothermal, Run of River, Wind, MSW
WACC	7%	7%	7%
Evaluation Period	40	40	40
Capital Cost (billion)	-	-	-
Unit Energy Cost (2013 $/MWh)	-	-	-
Adjusted Unit Energy Cost (2013 $/MWh)	**120**	**116**	**109**
MSW = Municipal Solid Waste. SCGT = Simple Cycle Gas Turbine Rev6 = Revelstoke Unit#6. GMS = Gordon M Shrum Units #1 - 5 - BC Hydro did not provide Capex or UECs for individual IPP projects			

Portfolios

Site C is a single, all or nothing project. IPPs are smaller projects. Portfolios of IPPs and other projects are more flexible and more cost-effective than Site C.

Many Alternative Portfolios

During the Hearing, we put forward 7 alternative portfolios. Three are shown here along with a fourth portfolio which combined the earlier three.

- Alternative #1 with Geothermal,
- Alternative #2A with Kleana Firm Energy
- Alternative #2B with Kleana Total Energy
- Alternative #3 with 6 Resources

Wide variety of project sizes, fuels and technologies

These portfolios contain over 40 different projects. They are powered by 7 different types of fuels or technologies. They range in size from 12 MW to 565 MW. They are located in every corner of B.C. They reflect the diversity of selection of alternative projects in B.C.

IPPs have identified over 1,000 potential renewable projects in BC[11]:

- 600 run-of-river projects;
- 400 wind projects;
- 40 biomass projects, and
- 16 geothermal projects.

BC Hydro's 2013 IRP lists many projects with UECs lower than Site C.

With limited time and resources, we have assembled new portfolios of projects that are more cost effective. The IPP sector can quickly assemble and propose other new portfolios with lower costs and very small environmental impacts.

All portfolios are designed to deliver the same output as Site C: 5,100 GWh and 1,100 MW.

The data that we have used in our calculations is limited to that provided by BC Hydro during the course of the hearing. If we used IPP-based data the cost of IPP projects and Alternative Portfolios would drop.

[11] Barton/Davis presentation December 10, 2013, slide 3 (CEAR #2093).

Calculation assumptions - WACC

Choice of WACC has a major impact on AUEC

As described in Chapter 1, the Adjusted Unit Energy Cost of a project (or a portfolio) is strongly impacted by the choice of Weighted Average Cost of Capital.

WEIGHTED AVERAGE COST OF CAPITAL (WACC)	**SITE C AUEC:** *(source)*	**CLEAN+THERMAL AUEC** *(source)*
5%	$94 *(Evidentiary Update)*	
6%	$110 *(Technical Memo)*	**UNKNOWN... $110???**
7%		$130 *(Evidentiary Update)*
8%		$155 *(Technical Memo)*

"**Evidentiary Update**" means BCH's *Evidentiary Update* dated September 13, 2013 (CEAR #1574)
"**Technical Memo**" means BCH's *Technical Memo – Alternatives to the Project* dated June 4, 2013 (CEAR #1458)

The difference between a 5% cost of capital amortized over 70 years and a 7% cost of capital amortized over 20 years (as BC Hydro imposes on all its wind project AUECs), adds over 80% to the capital portion of the UECs for all the wind projects used in the alternative portfolios. This introduces a large distortion into the evaluation of the alternatives to Site C.

Calculation Assumptions – Expected Project Life

BC Hydro calculates the UEC of Site C based on a 70 year life. Whereas, BC Hydro calculates the UEC of IPPs based on a 40 year life.

This is wrong in practice. Plus it substantially increases the relative UEC of IPPs. And it introduces a severe distortion to the Present Value differential analysis.

Contrary to the theme of the CD Howe Commentary

Similar to how the CD Howe Commentary recommended that project comparisons use equal WAAC, we expect that it would recommend assuming a project life is the same regardless of whether the project is owned by the government or the private sector.

Choice of Project Life

The maximum term for Water Licenses in BC is 40 years. This applies to BC Hydro projects as well as IPPs. While individual wind turbines often get replaced every 20 - 25 years, wind farm contracts range from 20 – 99 years.[12] In the 2008 Call for Power, wind power projects submitted bids to produce power up to the 40 year term that was allowed.

Site C is downstream of and totally reliant on the WAC Bennett Dam. It started operating in 1967. In 2024 it will be 57 years old. Forty years after Site C would start operating, it would be almost 100 years old.

The federal government limited the length of their loan guarantee for the Muskrat Falls to an amortization period of 35 years.

For our UEC and PV calculations we assume a project life of 40 years. And we apply that 40 year life to Site C and the Alternatives.

Geothermal

BC has great potential geothermal resources. BC Hydro's IRP[13] identified 780 MW and 5,992 GWh of Firm Energy of geothermal.

Page 6 of the BC Hydro Rebuttal dated December 23, 2013 concludes that geothermal is not viable because:

> *"… no geothermal resources were bid into BC Hydro's two most recent broadly-based power acquisition processes… There are no commercial geothermal electricity projects in B.C. at this time."*

As previously stated, we highlight that our submissions have only relied upon the 5 geothermal projects that were the 5 projects are already identified and evaluated by BC Hydro in the 2013 Resource Options Report Update of the 2013 Integrated Resources Plan.

In the last 5 years, wind power in BC has gone from non-existent to being the dominant source renewable generation. Wind power dominates all of the portfolio alternatives of BC Hydro's Evidentiary Update dated September 13, 2013 and the Technical Memo: Alternatives to the Project dated June 4, 2013.

Prior to 2009, there were no operational wind projects in BC. Today, there are 4 operating wind facilities in BC with a total generating capacity of 487 MW.

Of the approximately 200 renewable IPP bids that BC Hydro received prior to 2006 only two were from wind projects; therefore, the shift to over $1 Billion of wind capital expenditures in last 5 years has been dramatic and rapid.

Fast forward to wind's domination of the Clean Block. Wind power in BC has become so viable that BC Hydro's above optimization now completely excludes any run of river projects. This is presumably because small hydro is deemed uncompetitive on a cost basis. However, from 2000 to 2010, small run of river hydro projects were historically the dominant fuel of successful bidders. In the mid to late 1990's biomass and natural gas generation was dominant. Simply put, fuels and technologies change every few years.

The In-Service Date for Site C is 10 years from now. Competing alternatives such as geothermal have 10 years before they need to be in-service. That is a long time. Especially considering that there are over 11,000 MW of operating geothermal facilities in the world today.

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[12] Landowner Guidelines for evaluating wind energy production; https://www.msu.edu/~steind/**Wind**Lease-Easement_WorkSheet-V5.pd, Windenergyleases.blogspot.com states most contracts are written with options to make them last 60 years or more.

[13] BC Hydro in Table 3-15 of the 2013 Integrated Resource Plan

Alternative Portfolio #1 with 320 MW Geothermal

Alternative Portfolio #1 contains geothermal power totaling 320 MW of Dependable Generating Capacity and 2,504 GWh of Firm Energy in accordance with the 5 potential Lower Mainland sites identified in BC Hydro 2013 IRP.

This calculation is reproduced below with illustrated changes against the Clean Block of the Evidentiary Update (removals are shown as "strike-through" and additions are shown in gray):

ALTERNATIVE #1 WITH 320 MW GEOTHERMAL

PROJECT:	DEPENDABLE	ANNUAL FIRM	ADJUSTED UEC	TOTAL VARIABLE COST
Energy Costs	**CAPACITY (MW)**	**ENERGY (GWh)**	**(F2013/MWh)**	**($F2013 million)**
MSW2_LM	24	211	90	19
Wind_PC28		591	121	72
Wind_PC21		371	123	46
Wind_PC13		541	123	67
MSW1_VI	12	101	123	12
Wind_PC19		441	124	55
~~Wind_PC16~~		~~237~~	~~126~~	~~48~~
~~Wind_PC14~~		~~527~~	~~127~~	~~67~~
~~Wind_PC10~~		~~1623~~	~~129~~	~~132~~
~~Wind_PC15~~		~~382~~	~~130~~	~~50~~
~~Wind_PC20~~		~~609~~	~~131~~	~~80~~
~~Wind_VI12~~		~~151~~	~~131~~	~~20~~
~~Wind_VI14~~		~~113~~	~~132~~	~~15~~
WBBio_VI (50%)	44	354	138	49
320 MW Geothermal (LM)	320	2504	106	265
REV6 Variable Costs		26	12	0
GMS Variable Costs		0	0	0
~~*PS Variable Costs*~~		~~-364~~	~~19~~	~~7~~
SUBTOTAL	**400**	**5140**		**584**
	DEPENDABLE	**ANNUAL FIRM**	**UNIT CAPACITY COST**	**TOTAL FIXED COST**
Capacity Costs	**CAPACITY (MW)**	**ENERGY (GWh)**	**($F2013/kW-yr)**	**($F2013 million)**
REV6 Fixed Costs	488		50	24
GMS Fixed Costs	220		35	8
~~*PS Fixed Costs*~~	~~500~~		~~124~~	~~62~~
SUBTOTAL	**708**			**32**
	DEPENDABLE CAPACITY (MW)	**ANNUAL FIRM ENERGY (GWh)**	**ADJUSTED UEC ($F2013/MWh)**	**TOTAL COST ($F2013 million)**
TOTAL	**1108**	**5140**	**120**	**616**

As explained in Chapter 1 and 2, the AUEC for Site C should be in the range of $110 to $159. Therefore, Site C is not cost effective when compared to this alternative. The significant adverse impacts are no longer justified.

Kleana Unit Energy Cost

Kleana is a 565 MW run of river project proposed on Knight Inlet. It was presented to the Joint Review Panel.

Kleana is included as one of the projects in one of our Alternative Portfolios.

On January 23, 2014, BC Hydro dismissed Kleana, saying that it had very little dependable capacity and an AUEC that was greater than $140/MWh. BC Hydro dismissed Kleana by stating it is the same as all run of river:

> "*… this project has the adjusted unit energy cost of it north of $140 per megawatt hour.*
> *… the Kleana project is not substantially different than the run-of-river options that we'd shown in there. A similar sort of price; a similar sort of profile in terms of the energy delivered*." (Page 148)

We calculate, based on the information presented in the Hearing, the Unit Energy Cost of Kleana at the Point of Interconnection to be $80/MWh (UEC@POI). This is less expensive than the UEC@POI for Site C, at $95 based on WACC = 6% from the Technical Memo dated June 4, 2013. Also based on the information presented in the Hearing, we calculate the Adjusted Unit Energy Cost of Kleana to be $90 (delivered to the Lower Mainland).[14] This is less expensive than the AUEC for Site C, at $110 based on WACC = 6% from the Technical Memo dated June 4, 2013. This analysis shows that Kleana's lower AUEC is more cost-effective than Site C.

Since the project was bid into BC Hydro and was selected as a finalist, BC Hydro knows the energy and capacity production and has all necessary information to also confirm this Adjusted Unit Energy Cost.

Comparing a 565 MW run of river with a typical 5-10 MW run of river ignores economies of scale.

[14] Page 7 of 10 of Barton/Davis Questions from January 21, 2014 (CEAR #2626).

Alternative Portfolio #2A with 565 MW Kleana Project (Firm Energy Basis)

Based on the UEC of Kleana in the previous section, we propose an alternative to Site C which includes a portfolio of wind projects, municipal solid waste (MSW), Simple Cycle Gas Turbine (SCGT) projects and the Kleana Project.

Our calculations of this alternative result in an AUEC of $116 based on firm energy.

This calculation is reproduced below with illustrated changes against the Clean+Thermal Block #2 of the Evidentiary Update (removals are shown as "strike-through" and additions are shown in gray)

ALTERNATIVE #2A WITH 565 MW KLEANA (1770 GWH OF FIRM ENERGY)

Energy Costs	**CAPACITY (MW)**	**ENERGY (GWh)**	**($F2013/MWh)**	**($F2013 million)**
MSW2_LM	24	211	90	19
Wind_PC28		591	121	72
Wind_PC21		371	123	46
Wind_PC13		541	123	67
MSW1_VI	12	101	123	12
Wind_PC19		441	124	55
Wind_PC16		377	126	48
Wind_PC14		325	127	41
~~Wind_VI14~~		~~113~~	~~132~~	~~15~~
~~Wind_PC11~~		~~473~~	~~133~~	~~63~~
~~Wind_PC09~~		~~713~~	~~133~~	~~95~~
565 MW Kleana Run-of-River	135	1770	90	159
REV6 Variable Costs		26	12	0
GMS Variable Costs		0	0	0
SCGT Variable Costs		354	66	23
SUBTOTAL	**171**	**5108**		**542**
Capacity Costs	**DEPENDABLE CAPACITY (MW)**	**ANNUAL FIRM ENERGY (GWh)**	**UNIT CAPACITY COST ($F2013/kW-yr)**	**TOTAL FIXED COST ($F2013 million)**
REV6 Fixed Costs	488		50	24
GMS Fixed Costs	220		35	8
SCGT Fixed Costs	225		88	20
SUBTOTAL	**933**			**52**
	DEPENDABLE CAPACITY (MW)	**ANNUAL FIRM ENERGY (GWh)**	**ADJUSTED UEC ($F2013/MWh)**	**TOTAL COST ($F2013 million)**
TOTAL	**1104**	**5108**	**116**	**593**

Necessary for the portfolio above is the following:

- we calculate that Kleana should provide 1,770 GWh of Firm Energy from a Total Energy of 2,450 GWh – this is based on the 2008/2010 Clean Power Call which illustrates that the ratio of Firm Energy to Total Energy should be 72.2% (Table 3–5, BC Hydro Report on the RFP Process for the Clean Power Call, August, 2010);

- we calculate that Kleana should provide 135 MW of Dependable Capacity from a Nameplate Capacity of 565 MW – this is based on Table 3-13 of the 2013 IRP which illustrates that 24% is the ratio of Effective Load Carrying Capacity to Installed Capacity for run of river projects based in the Vancouver Island Transmission Region.

As explained in Chapter 1 and 2, the AUEC for Site C should be in the range of $110 to $159. Therefore, Site C is not cost effective when compared to this alternative. The significant adverse impacts are no longer justified.

Alternative Portfolio #2B with 565 MW Kleana (Total Energy Basis)

The UEC of this large project should also be considered on a total energy basis because dependable capacity is being provided by Rev6, GMS, MSW and SCGT.

We calculate that a portfolio using the 2,450 GWH of Total Energy from Kleana results in an AUEC of only $111.

This calculation is reproduced below with illustrated changes against the Clean+Thermal Block #2 of the Evidentiary Update (removals are shown as "strike-through" and additions are shown in gray):

ALTERNATIVE #2B WITH 565 MW KLEANA (2450 GWH OF TOTAL ENERGY)

PROJECT:	DEPENDABLE	ANNUAL FIRM	ADJUSTED UEC	TOTAL VARIABLE COST
Energy Costs	**CAPACITY (MW)**	**ENERGY (GWh)**	**($F2013/MWh)**	**($F2013 million)**
MSW2_LM	24	211	90	19
Wind_PC28		591	121	72
Wind_PC21		371	123	46
Wind_PC13		541	123	67
MSW1_VI	12	101	123	12
Wind_PC19		441	124	55
~~Wind_PC16~~		~~377~~	~~126~~	~~48~~
~~Wind_PC14~~		~~527~~	~~127~~	~~67~~
~~Wind_VI14~~		~~113~~	~~132~~	~~15~~
~~Wind_PC11~~		~~473~~	~~133~~	~~63~~
~~Wind_PC09~~		~~713~~	~~133~~	~~95~~
565 MW Kleana Run-of-River	135	2450	90	221
REV6 Variable Costs		26	12	0
GMS Variable Costs		0	0	0
SCGT Variable Costs		354	66	23
SUBTOTAL	**171**	**5086**		**514**
	DEPENDABLE	**ANNUAL FIRM**	**UNIT CAPACITY COST**	**TOTAL FIXED COST**
Capacity Costs	**CAPACITY (MW)**	**ENERGY (GWh)**	**($F2013/kW-yr)**	**($F2013 million)**
REV6 Fixed Costs	488		50	24
GMS Fixed Costs	220		35	8
SCGT Fixed Costs	225		88	20
SUBTOTAL	**933**			**52**
	DEPENDABLE	**ANNUAL FIRM**	**ADJUSTED UEC**	**TOTAL COST**
	CAPACITY (MW)	**ENERGY (GWh)**	**($F2013/MWh)**	**($F2013 million)**
TOTAL	**1104**	**5086**	**111**	**566**

These Kleana portfolios results in AUEC of only $111 or $116, depending on whether one uses 1770 GWh of Firm Energy or 2,450 GWh of Total Energy.

As explained in Chapter 1 and 2, the AUEC for Site C should be in the order of $110 to $159. Therefore, Site C is not cost effective when compared to this alternative. The significant adverse impacts are no longer justified.

Alternative Portfolio #3 with 6 Types of Resources

We have also designed another Alternative which combines both geothermal and Kleana. For supply diversity, this portfolio also includes small run of river projects from Appendix 3A-34 of the 2013 IRP.

This calculation is reproduced below with illustrated changes against the Clean Block of the Evidentiary Update (removals are shown as "strike-through" and additions are shown in gray):

ALTERNATIVE #3 WITH 6 RESOURCE OPTIONS

PROJECT: Energy Costs	DEPENDABLE CAPACITY (MW)	ANNUAL FIRM ENERGY (GWh)	ADJUSTED UEC ($F2013/MWh)	TOTAL VARIABLE COST ($F2013 million)
MSW2_LM	24	211	90	19
Wind_PC28		591	121	72
Wind_PC21		100	123	12
~~Wind_PC13~~		~~541~~	~~123~~	~~67~~
~~MSW1_VI~~	~~12~~	~~101~~	~~123~~	~~12~~
~~Wind_PC19~~		~~441~~	~~124~~	~~55~~
~~Wind_PC16~~		~~377~~	~~126~~	~~48~~
~~Wind_PC14~~		~~527~~	~~127~~	~~67~~
~~Wind_PC10~~		~~1023~~	~~129~~	~~132~~
~~Wind_PC15~~		~~382~~	~~130~~	~~50~~
~~Wind_PC20~~		~~609~~	~~131~~	~~80~~
~~Wind_VI12~~		~~151~~	~~131~~	~~20~~
~~Wind_VI14~~		~~113~~	~~132~~	~~15~~
250 MW Geothermal (LM)	250	1970	102	201
565 MW Kleana Run-of-River	135	1770	90	159
ROR_100-110_VI		450	143	64
REV6 Variable Costs		26	12	0
GMS Variable Costs		0	0	0
~~*PS Variable Costs*~~		~~364~~	~~19~~	~~7~~
SUBTOTAL	**409**	**5118**		**528**
Capacity Costs	**DEPENDABLE CAPACITY (MW)**	**ANNUAL FIRM ENERGY (GWh)**	**UNIT CAPACITY COST ($F2013/kW-yr)**	**TOTAL FIXED COST ($F2013 million)**
REV6 Fixed Costs	488		50	24
GMS Fixed Costs	220		35	8
~~*PS Fixed Costs*~~	~~500~~		~~124~~	~~62~~
SUBTOTAL	**708**			**32**
	DEPENDABLE CAPACITY (MW)	**ANNUAL FIRM ENERGY (GWh)**	**ADJUSTED UEC ($F2013/MWh)**	**TOTAL COST ($F2013 million)**
TOTAL	**1117**	**5118**	**109**	**560**

As explained in Chapter 1 and 2, the AUEC for Site C should be in the order of $110 to $159. Therefore, Site C is not cost effective when compared to this alternative. The significant adverse impacts are no longer justified.

Comparing Alternative Portfolios to Site C

The following table compares 5 portfolios. The first two columns show Site C, before and after our suggested financial and capital cost adjustments. The last 3 columns show Alternative Portfolios we have assembled.

Portfolio Name	***Site C***	***Site C***	***Site C***	***Alternative Portfolio #1***	***Alternative Portfolio #2A***	***Alternative Portfolio #3***
Source of Data or Description of Portfolio or Scenario	BC Hydro June 4 Tech Memo	BC Hydro June 4 with Adjusted Financial Asumptions	Adjusted Capex and Financial Assumptions	Geothermal @ 320 MW	Kleana (Firm Energy)	Six Resources
Source of Capacity	Site C	Site C	Site C	Geothermal, GMS, Rev6, MSW	Kleana, GMS, Rev6, MSW	Kleana, Geothermal GMS, Rev6, MSW
Source of Energy	Site C	Site C	Site C	Geothermal, Rev6, Wind, MSW	Kleana, Rev6, Wind, MSW, SCGT	Kleana, Rev6, Geothermal, Run of River, Wind, MSW
WACC	6%	7%	7%	7%	7%	7%
Evaluation Period	70	40	40	40	40	40
Capital Cost (billion)	7.9	7.9	10.3	-	-	-
Unit Energy Cost (2013 $/MWh)	94	115	143	-	-	-
Adjusted Unit Energy Cost (2013 $/MWh)	**110**	**131**	**159**	**120**	**116**	**109**

MSW = Municipal Solid Waste. SCGT = Simple Cycle Gas Turbine

Rev6 = Revelstoke Unit#6. GMS = Gordon M Shrum Units #1 - 5

- BC Hydro did not provide Capex or UECs for individual IPP projects

4. Independent Review of Alternatives Recommended

EIS Review focused on environmental not economic issues

The E in the EIS review stands for environment, not economics.

It is not surprising that an Environmental Impact Study focused much more on environmental matters than economic matters. Indeed we appreciate the Panels efforts to allocate time to consider the need for and alternatives to the Project during their deliberations over other environmental matters.

Unfortunately there was not enough time to investigate financial matters surrounding a project of this scale. Site C will require significant public investment. That will have a significant impact on ratepayers, and perhaps taxpayers too. It is the only power generation planned in B.C. for the next 20 years. Unfortunately this EIS review has been the only recent public review process for the project.

Not surprisingly, the format of the public hearing process was not well suited for making a accurate comparison of Site C versus alternatives. We understand that most EIS reviews do some kind of review of the Needs for and Alternatives (NFAT) to the Project being studied. But we also understand that most major projects have economic, financial and NFAT issues also scrutinized by organizations with the capacity and responsibility to focus on economic issues.

Shortage of financial information and detailed financial models

We found it difficult to accurately compare Site C to Alternative Portfolios without seeing any financial spreadsheets and detailed modeling.

We posed several questions on January 15 and 21, 2014. For example, on January 15 Question #2 concluded:

> *"What amount has BC Hydro included as an allowance for equity costs during construction, which we have estimated to be at least $678 million? Please provide a spreadsheet showing the detailed year by year capital expenditures and the calculations of both IDC and ECDC."*

And also as part of Question #3 stated;

> *"Please provide a working spreadsheet showing the all estimated Site C expenditures by year, including any allowances for allocated overhead charges, and showing how the discounted present values of the expenditures and the generation are determined, and the detailed calculation of the unit energy cost attributed to the project.*

The Panel reflected some of our questions in the questions that they posed to BC Hydro on January 23. We appreciate the Panel asking parts of those questions.

However, our questions were much more detailed than the summary level questions asked by the Panel. Our questions aimed at getting BC Hydro to reveal the assumptions and calculations behind several of their cost figures. BC Hydro's answers were often quite general and revealed few numerical assumptions or calculations.

BC Hydro wears many hats

BC Hydro wrote the 2013 Integrated Resource Plan. The IRP recommended continuing to develop Site C. Under the Base Resource Plan, Site C is the only generation project recommended by BC Hydro over the next 20 years.

In the EIS, BC Hydro created several Alternative Portfolios to compare to their Site C project, BC Hydro then analyzed those alternatives using their financial models and concluded that their Site C project was the most cost-effective.

In this process, BC Hydro is the planner, the buyer, the seller, the creator of all Alternative Porfolios, and the modeler of the financial comparisons.

The BCUC 1983 Decision on Site C indicated that one of the reasons for rejecting Site C was that there were alternatives to the project.

Precedent for Independent Review of Alternatives: Muskrat Falls

In response to a recent application for another major Canadian hydropower project, an independent review of alternatives was recommended.

Lower Churchill: 824 MW Muskrat Falls Dam and 2250 MW Gull Island Dam

An important determination in the August 11, 2011 decision of the Joint Federal-Provincial Review Panel for the Lower Churchill projects was the **inadequate** analysis of alternatives of Nalcor (Newfoundland and Labrador energy corporation):

*"**Alternatives to the Project***
Nalcor considered a list of potential alternatives and concluded that none were economically or technically feasible compared to the Project and none could meet the stated need to develop the hydroelectric potential of the Churchill River.
…

However, the Panel concluded that Nalcor's analysis, showing Muskrat Falls to be the best and least-cost way to meet domestic demand requirements, was inadequate and recommended a new, independent analysis based on economic, energy and environmental considerations."
(emphasis added; page 3 of Executive Summary)[15]

Furthermore, the Joint Federal-Provincial Review Panel makes several recommendations including the recommendation of independent analysis:
""RECOMMENDATION 4.2 Independent analysis of alternatives to meeting domestic demand

The Panel recommends that, before governments make their decision on the Project, the Government of Newfoundland and Labrador and Nalcor commission an independent analysis to address the question "What would be the best way to meet domestic demand under the 'No Project' option …"

(emphasis added; page 25 of Executive Summary)

[15] See: http://www.ceaa-acee.gc.ca/050/documents/51706/51706E.pdf

Several of the additional recommendations were similar to issues facing Site C. We pointed to several in our January 15 letter to the Panel. Below is a side-by-side comparison:

Recommendations of the Joint Federal-Provincial Review Panel for Lower Churchill: (***Page 25 of Executive Summary***)	**Similarity to Site C:**
The analysis should address the following considerations: *why Nalcor's least cost alternative to meet domestic demand to 2067 does not include Churchill Falls power which would be available in large quantities from 2041, or any recall power in excess of Labrador's needs prior to that date, especially since both would be available at near zero generation cost (recognizing that there would be transmission costs involved);*	The possibility of "recalling power" is similar to Question 13 from our January 15 Questions: WHY DID BC HYDRO NOT INCLUDE THE COST EFFECTIVE 560 MW OF CAPACITY AVAILABLE UNDER THE COLUMBIA NON-TREATY STORAGE AGREEMENT AS OPTIONS FOR ALTERNATIVE PORTFOLIOS WITH IPPS?
the extent to which Nalcor's analysis looked only at current technology and systems versus factoring in developing technology;	The ability to respond to technology is similar to Question 1 from our January 15 Questions: IN RESPONSE TO FUTURE CHANGES, WHY HAS BC HYDRO ASCRIBED ZERO VALUE TO THE FLEXIBILITY OF IMPLEMENTING A DOZEN INDIVIDUAL PROJECTS VS. THE SINGLE ALL OR NOTHING MEGA-PROJECT SITE C?
the suggestion made by the Helios Corporation that an 800 MW wind farm on the Avalon Peninsula would be equivalent to Muskrat Falls in terms of supplying domestic needs, could be constructed with a capital cost of $2.5 billion, and would have an annual operating cost of $50 million and a levelized cost of power of 7.5 cents per kilowatt-hour;	Similar to our Question 16 from our January 15 Questions: WHY DID BC HYDRO NOT INCLUDE THE 565 MW KLEANA HYDRO PROJECT IN AN ALTERNATIVE PORTFOLIO?
potential for renewable energy sources on the Island (wind, small scale hydro, tidal) to supply a portion of Island demand.	There are many possible portfolios containing wind, small scale hydro and other renewables. We have designed just a few alternative portfolios.

Recommendation for Independent Review of Alternatives

We suggest that the Panel consider recommending an Independent Review of Site C vs alternatives. We suggest that such Independent Review include complete financial information to allow an open analysis of the costs, financial figures and methodology for calculating costs of Site C and alternative projects.

More specifically, the Independent Reviewer should require that BC Hydro supply all spreadsheets, calculations and data that illustrate how they arrive at all costs (i.e. UEC's and PVs) for each portfolio and independent projects. There should also be sufficient time given to independently review these data and information for comment and recommendations for improvement. The Independent Review should aim to create a level playing field between Site C and competing alternatives.

5. Appendix

Project Overrun Contingency Analysis

BC Hydro stated the following in Section 5.5.1.1 of the EIS:

> *Project cost estimate of $7.9 billion has a Class 3 (budget authorization or control) degree of accuracy, as defined by the Association for the Advancement of Cost Engineering (AACE 2012). Refer to Volume 1 Appendix F Project Benefits Supporting Documentation, Part 1 Project Cost Estimate for additional detail. A Class 3 degree of accuracy is consistent with the BCUC's requirements for project cost estimates set out in the BCUC 2010 Certificate of Public Convenience and Necessity Application Guidelines.(emphasis added)*

BC Hydro stated the following in response to IR27 (page 12)

> *Project cost estimate is a Class 3 cost estimate as defined by the Association for the Advancement of Cost Engineering (with an accuracy range between +10/-10 and +30/-20.*

As such the analysis was undertaken to compare previous project budgets submitted by BC Hydro to the BCUC in support of project CPCN's or General Order approvals. These could then be compared to project costs submitted by BC Hydro in support of Revenue Requirements that BC Hydro submits on a regular basis. This would provide a fair and independent assessment of potential cost overruns based on BC Hydro's track record. Our original analysis of projects provided in our January 15, 2014 letter was based on the approved BCUC Order and Final cost derived from BC Hydro's most recent Amended F12/F14 Revenue Requirement Application – Appendix I and J submitted to the BCUC.

The January 15, 2014 analysis showed that based on a comparison of 43 projects with a total BCUC Order approved budget of $3.078 Billion dollars which represented 93% of BC Hydro's stated capital budget of $3.3 Billion that the overage was 23%.

Subsequent to this, BC Hydro responded at the January 23, 2014 Final Hearing. The Panel directed BC Hydro to submit a revised table comparing projects greater than $50 million (see CEAR #2714). We reviewed this table and our analysis on the next page identifies an overage of 16% which compares to 3.3% from CEAR #2714. The analysis is primarily different because BC Hydro compared based on the first implementation estimate (see BC Hydro Final Hearing, Page 139, Line 7) instead of the CPCN estimate. In addition, we disagree as explained in the subsequent notes. We are satisfied with our review and that independently verifiable information supports our analysis, not BC Hydro's numbers.

We note that the main cost overruns experienced by BC Hydro on NTL ($332M or 86%), the overages were the result from First Nations accommodation, costs arising from EAC requirements, legal costs arising from EAC and CPCN appeals (see CEAR #2682). The same very costs which are not included in BC Hydro's Site C estimate, yet are indeed included in the Clean Block and Clean+Thermal.

Our analysis determines that the average overrun on BC Hydro's large capital projects is 16%:

Analysis of the BC Hydro Cost Overrun Reconciliation Presented at Closing Hearing on January 23, 2014 (CEAR #2714)

Project	BCUC Order	BCUC Order Approved Cost	Final Cost per BCH/BCTC Revenue Requirement F12/F14 - Appendix I Amended	Year	Project Cost Differential	Comments
Generation Projects - Completed						
Aberfeldie	C-02-07	$64,000,000	$95,000,000	F12-F14	48%	See Note 1
Revelstoke Unit 5	C-08-07	$280,000,000	$250,000,000	F12-F14	-11%	Agreed With BCH
Fort Nelson Resource Smart	G-75-09	$140,100,000	$165,200,000	F12-F14	18%	Agreed With BCH
Coquitlam Dam Seismic Upgrade	G-143-06	$58,000,000	$64,900,000	???	12%	See Note 2
GMS 1-4 Stator Replacement	G-143-06	$83,000,000	$81,400,000	F12-F14	-2%	See Note 3
PCN G1-G4 Stators	G-143-06	$67,000,000	$72,500,000	F12-F14	8%	See Note 4
Mica G1-G4 Stator Replacement	G-143-06	$78,000,000	$86,200,000	F12-F14	11%	See Note 5
Generation Projects - Implementation						
GMS Unit 1-5 Replacement	G-01-10	$262,000,000	$246,300,000	F12-F14	-6%	See Note 6
Mica Gas Insulated Switchgear	G-38-10	$180,600,000	$190,400,000	F12-F14	5%	See Note 7
Stave Falls Spillway Gates	G-81-10	$61,500,000	$66,000,000	F12-F14	7%	See Note 8
Mica Units 5&6	Exempt by CEA	$627,000,000	$675,000,000	F12-F14	8%	See Note 9
HLK Spillway Gates	G-177-10	$90,200,000	$102,500,000	F12-F14	14%	Agreed With BCH
Ruskin Dam and Power House Upgr	G-5-12	$640,600,000	$750,000,000	F12-F14	17%	See Note 10
Transmission Projects - Completed						
VTR	C-04-06	$249,000,000	$308,000,000	F12-F14	24%	Agreed With BCH
Central Vancouver Island	C-06-08	$91,600,000	$62,750,000	F12-F14	-31%	Agreed With BCH
Columbia Valley Transmission	C-05-10	$154,100,000	$133,000,000	F12-F14	-14%	See Note 11
Transmission Projects - Implementation						
Interior Lower Mainland	C-04-08	$602,000,000	$752,000,000	F12-F14	25%	See Note 12
Vancouver City Central Transmissio	C-03-10	$189,000,000	$174,500,000	F12-F14	-8%	See Note 13
Northwest Transmission Line	Exempt by CEA	$404,000,000	$736,000,000		82%	See Note 14
Dawson Creek/Chetwynd Area Transmission (DCAT)	C-5-13	$222,300,000	$296,400,000	F12-F14	33%	See Note 15
Seymour Arm Series Capacitor	G-87-09	$65,300,000	$53,000,000	F12-F14	-19%	See Note 16
Smart Meter Intiative	Exempt by CEA	N/A	N/A			See Note 17

CEA means Clean Energy Act

TOTALS	**$4,609,300,000**	**$5,361,050,000**	**16%**

1.	Aberfeldie: BCH states that the "Original Budget" for Aberfeldie was $83M. This is not correct. BCH originally submitted Aberfeldie to the BCUC for approval with a cost estimate of $45M (Oct 2004, P50) and $65M (Feb 2006, P50) in the F07/F08 RRA. During the process of the F07/F08 RRA the BCUC did not approve the Aberfeldie project, and the project was subjected to a Negotiated Settlement Agreement (NSA). In support of the NSA, BCH further updated the cost from $65M to $83M (Nov 2006) with an upper bound estimate of $94M (+13%). Aberfeldie demonstrates difficulty BCH had cost estimating project even at P50 level to support BCUC regulatory approval.
2.	Coquitlam Dam Seismic Upgrade: We did not include the Coquitlam Upgrade because the project is not identified in the Amended F12/F14 RRA, Appendix I. We can provide no comment on the final cost.
3.	GMS 1-4 Stator Replacement: BCUC Order G-143-06 approved a cost of $46M for G3 & G4 stators (Implementation) and $37M for G1 and G2 (Definition) for a total of $83M. The project cost item in the Amended F12/F14 RRA for G1 to G4 ranges from $78.4M to $84.4M with the midpoint being $81.4M.
4.	PCN G1-G4 Stators: The BCUC approved cost was $67M . Amended F12/F14 RRA Appendix I has a completed cost of $72.5M.
5.	Mica G1-G4 Stator Replacement: Mica G1-G4 was indeed included in our Appendix 1 Analysis – it was included in BCUC Order G-143-06.
6.	GMS Unit 1-5 Replacement: We agree with the Original Budget of $262M for GMS Unit 1-5 Replacement. We disagree with a Final Cost of $198M because the final cost as provided by the Amended F12/F14 RRA ranges from $202.8M to $289.8M with a midpoint of $246.3M (Total Cost). Furthermore, the F2011 NSA-12 Total Cost Column ranges from $262M to $319M with a midpoint of $290.5M. Also, Appendix J provides a Forecast Capital Cost of $246.9M to $313.9M with a midpoint of $280.4M . Lastly, BC Hydro Service Plan 2013/14 to 2015/16 has a range of $197M to $272M with a midpoint of $234.5M. Therefore, our Final Cost is $246.3M.
7.	Mica Gas Insulated Switchgear: We agree with the Original Budget of $180M for Mica Gas Insulated Switchgear. However, same logic as above: the final cost as provided by the Amended F12/F14 RRA ranges from $169M to $188.6M with a midpoint of $178.8M based on numbers in the Total Cost column. The number in the F2011 NSA-12 Total Cost Column is $200M which is closer to BCH's number. Appendix J provides a Forecast Capital Cost of $180.6M to $200.2M with a midpoint of $190.4M. Therefore, our Final Cost is $190.4M.
8.	Stave Falls Spillway Gates: The final cost provided in the Amended F12/F14 RRA ranges from $61.2M to $66.1M with a midpoint of $63.65M. In the F2011 NSA-12 Total Cost Column, the range is from $61.5M to $70.6M with a midpoint of $66.1M. Appendix J provides a Forecast Capital Cost of $66.9M to $71.8M with a midpoint of $69.4M. Therefore, our Final Cost is $66M.
9.	Mica Units 5 & 6: We excluded Mica Units 5&6 in our Appendix 1 Analysis because of exemption from BCUC review. We agree with the BCH's Original Budget of $627M. However, we disagree with BCH's Final Cost of $627M. The final cost provided in the Amended F12/F14 RRA ranges from $638.7M to $738.7M with a midpoint of $688.7M. The F2011 NSA-12 Total Cost Column ranges from $640M to $950M with a midpoint of $795M. Appendix J provides a Forecast Capital Cost of $700M to $800M with a midpoint of $750M. BC Hydro's 2013/2014 -2015/2016 Service Plan identifies the project cost for Mica 5/6 as $627M to $714 with a midpoint of $670.5M. All these exceed BCH's cost of $627M and as a minimum we use a Final Cost of $675M which illustrates an increase of $48M or 8%. Our previous exclusion of this project favoured BCH but we can certainly include this project.
10.	Ruskin Dam and Power House Upgrade: We agree with BCH's Original Budget of $640M. However, we disagree with BCH's Final Cost of $640M. The Total Cost identified in Appendix I of the Amended F12/F14 RRA ranges from $662.3M to $801.1M with a midpoint of $731.7M. Appendix J of the Amended F12/F14 RRA has a forecast expected cost ranging from $728.6M to $867.4M with a midpoint of $798M. We use a Final Cost of $750M.

11.	Columbia Valley Transmission: The Amended F12/F14 RRA Appendix I project cost is provided as $133M and this is low end of the range provided in Appendix J of $132 million to $209 million. We use a Final Cost of $133M.
12.	Interior to Lower Mainland: We agree with the BCH's Original Budget of $602M. However, this CPCN project cost of $602M (P50) did not include FN accommodation costs, environmental mitigation and compensation, and costs for legal challenges. We disagree with BCH's Final Cost of $690M. Note T10 stipulates the ILM project has increased in cost by $150M or 25% (CEAR #2682) mainly due to FN accommodation costs, costs arising from EAC requirements, legal costs arising from EAC and CPCN appeals. In Appendix J the Forecast Capital Cost is a range from $540M to $780M. This range is -10% to +30% from the $603M CPCN cost or P50. We confirm based on Note T10 the Project cost used in the Analysis should be $752M. We also highlight that the BCUC has set a threshold of $725M (P50, $2014) for the project which was to include FN accommodation costs, costs arising from EAC requirements, legal costs arising from EAC and CPCN appeals. This threshold has been exceeded based on the cost provided by BC Hydro in Note T10.
13.	Vancouver City Central Transmission: We disagree with the BCH's Original Budget of $201M because this was based on the CPCN approved cost of $174M (Transmission) and $27M (Distribution) which was to be reduced by savings from a tunnel crossing of False Creek – which was ultimately successful for total savings of $12M (see Exhibit ____). Therefore the CPCNproject was subsequently undertaken using HDD. Therefore, the CPCN approved cost became $189M. We also disagree with BCH's Final Cost - the cost as identified in the Amended F12/F14 RRA is $176.9M.
14.	Northwest Transmission Line: NTL was excluded from BCUC review so we could only rely on the budget submission provided to the Federal Government for federal funding. The funding budget was $404M and there were three funding partners: $180M from AltaGas; $130M from Federal Government and $94M from BC Hydro/BCTC ratepayer. BC Hydro 2013/2014 -2015/2016 Service Plan identifies the project cost for NTL as $736M to $746M with a midpoint of $741M. The project cost identified in the Amended F12/F14 RRA is $561M which excludes the $180M contribution from AltaGas. The reasons for the overrun are outlined in Appendix J of the Amended F12/F14 RRA and CEAR #2682 as related to First Nations IBF's, EAC compensation, cost updates (see attached Exhibit H-14).
15.	Dawson Creek / Chetwynd Area Transmission (DCAT): We did not consider this project in Appendix 1 Analysis because the project was noted as being in the Definition Phase in the Amended F12/F14 RRA. We agree with the BCH Reconciliation.
16.	Seymour Arm Series Capacitors: We did not consider this project in Appendix 1 Analysis because the project was noted as being in the Definition Phase in the Amended F12/F14 RRA. We agree with the BCH Reconciliation.
17.	Smart Meter Initiative: This project has no business being included with complex construction projects because only involves replacing the old analog small residential, commercial, and industrial meters with new digital meters. The process only takes 20 minutes. Smart Meters has no relation to projects involving extensive civil, mechanical, electrical, geotechnical, environmental compensation, large scale project management and FN accommodation.

All the above notes are further described in Exhibit A. Supporting Data from BCUC Proceedings.

Exhibit A

Supporting Data from BCUC Proceedings

[attached]

4.2.3 Determinations Sought in F07/F08 RRA

The proposal described above is not as readily apparent in this application as it might have been because of various commitments BC Hydro made in the 2005 REAP NSP. Pursuant to the 2005 REAP NSP BC Hydro committed to seeking, and does seek, section 45(6.2)(b) determinations in respect of:

- Its complete F2007 capital plan.
- All committed capital expenditures at the Mica, GM Shrum, John Hart and Ruskin facilities.
- In addition, and consistent with the proposed capital plan review process described above, BC Hydro seeks in this application section 45(6.2)(b) determinations in respect of the Aberfeldie Redevelopment, Coquitlam Dam Seismic Improvements, and Peace Canyon Stators projects. Each of these projects now meets the threshold test.

BC Hydro anticipates that if its capital plan review proposal is accepted it would, within the next two years, seek BCUC determinations in respect of the following projects (on the assumption that they meet the threshold test in that period):

- Advanced Metering Infrastructure project;
- EE3, EE4 and EE5[1] (implementation stage);
- John Hart project (implementation stage); and
- Ruskin project (implementation stage);

This application specifically excludes the three projects that are subject to a BCUC determination through review of the LTAP, namely the definition phase of EE3, EE4 and EE5, definition phase of Revelstoke Unit 5, and identification and definition phases of the

[1] Future energy efficiency programs—see 2006 IEP at Appendix E for a description.

EXHIBIT H-1

18. BC Hydro's planned capital expenditures in the following amounts and in regard to the following projects are "in the interests of persons within British Columbia who receive, or who may receive, service" from BC Hydro, pursuant to section 45(6.2)(b) of the UCA:

i. $46 million, G3 & G4 stators at GM Shrum (Appendix I of the F07/F08 RRA);

ii. $12 million, DC System at GM Shrum (Appendix I of the F07/F08 RRA);

iii. $78 million, G1-G4 stators at Mica (Appendix H of the F07/F08 RRA).

iv. $58 million, Coquitlam Dam seismic improvements (Appendix N of the F07/F08 RRA); and

v. $67 million, G1-G4 stators at Peace Canyon (Appendix M of the F07/F08 RRA).

CAPITAL PLAN REVIEW PROCESS

19. BC Hydro will file its Capital Plan bi-annually. The Capital Plan will identify all capital expenditures and for the purposes of this provision the term "capital expenditures" will include those demand-side management expenditures that are amortized, in the then-current fiscal period and the following fiscal period, as well as total expenditure and in-service date forecasts for projects underway in those periods. In addition, the Capital Plans will specifically identify projects with gross project costs greater than $2 million on an aggregated basis. These bi-annual filings will satisfy BC Hydro's obligations under sections 45(6.1)(a) and (c) of the UCA. BC Hydro will notify stakeholders of these filings. For greater certainty, these filings and any filings made pursuant to paragraphs 20 and 21 will not preclude Parties from raising prudency issues under the UCA with respect to costs incurred or to be incurred.

20. BC Hydro will file Major Threshold Project applications for determinations under section 45(6.2)(b) of the UCA in regard to Major Threshold Projects that are ready to proceed, supported by detailed ("CPCN-like") business cases. BC Hydro will notify stakeholders of these applications at the time they are filed. Major Threshold Projects are all capital projects with gross project costs, including without limitation contributions in aid of construction, transmission interconnection costs and upgrades and the amount of any First Nations costs attributable to the relevant project, greater than $50 million, plus other projects which BC Hydro believes should

EXHIBIT H-2

7.14.3.6 *Other Implementation Phase Projects*

Project	Total Project Cost	Estimated In-Service	Previously Reviewed	UCA section 45(6.2)(b) Determination Sought
Aberfeldie Redevelopment	$64 million	F2008	2005 REAP • Application p.3-24, p.3-54 to 3-55 • BCUC IR #1.51.0, 2.96.1, 2.96.2 • IPPBC IR #1.1.0, 1.2.0, 1.3.0, 1.4.0, 1.5.0, 1.6.0 F05/F06 RRA • Application p.11-12, 11-18 • BCUC IR #1.5.40 • CECBC IR #1.23.1 • WAIT IR #3.2.0 IPPBC IR #1.61.4, 1.61.5	$64 million (Total Cost, per BCH proposal)
Lake Buntzen Coquitlam Dam Seismic Improvements	$58 million	F2008	2005 REAP • Application p.3-23, 3-42 • BCUC IR#1.44.1, 1.44.2, 1.44.3 F05/F06 RRA Application p.11-11, 11-16	$58 million (Total Cost, per BCH proposal)
Mica G1-G4 Stator Replacement	$78 million	F2007-F2010	2005 REAP • Application p.3-23, 3-35, 3-36 • BCUC IR #1.34.2, 1.35.1, 1.35.2, 1.42.1, 1.42.2, 1.42.3, 1.42,4, 2.92.1, 2.92.2, 2.92.4 F05/F06 RRA (Mica Unit 4 Stator Replacement) • Application p.11-12, 11-19 • BCUC IR#1.5.30	$78 million (Total Cost, per BCH proposal and 2005 REAP NSP)
GM Shrum G3 and G4 Stator Replacement	$46 million	F2008-F2009	2005 REAP • Application p.3-25, 3-30 • BCUC IR#1.34.2, 1.35.1, 1.35.2, 1.39.1, 1.39.2, 1.42.1, 1.42.2, 1.42.3, 1.42.4, 2.92.3 F05/F06 RRA – plan at the time to rewind each unit has been superceded.	$46 million (Total Cost, per 2005 REAP NSP)
GM Shrum DC System & Unit Protection Upgrade	$12 million	F2008	2005 REAP • Application p3-23, 3-29 F05/F06 RRA (called GM Shrum Unit Transformer and Generators Protection) • Application p.11-12, 11-19	$12 million (Total Cost, per 2005 REAP NSP)
Peace Canyon G1 to G4 Stator Implementation	$76 million	F2007-F2010	2005 REAP • Application p.3-23, 3-40, 3-41 • BCUC IR #1.34.1, 1.34.2, 1.35.1, 1.42.1, 1.42.2, 1.42.3, 1.42.4 F05/F06 RRA (called Peace Canyon Generator Deficiency Project) • Application p.11-12, 11-19	$67 million (Total Cost, per BCH proposal)

7.14.4.2 Other Definition Phase Projects

Project	Total Project Cost	Estimated In-Service	Previously Reviewed	UCA section 45(6.2)(b) Determination Sought
GM Shrum G1 and G2 Stator Replacement	$37 million	F2010-F2011	2005 REAP • Application p.3-25, 3-30 • BCUC IR#1.34.2, 1.35.1, 1.35.2, 1.39.1, 1.39.2, 1.42.1, 1.42.2, 1.42.3, 1.42.4, 2.92.3 F05/F06 RRA – plan at the time to rewind each unit has been superceded.	(No F2007 costs)
GM Shrum Capacity Increase	$20 million	F2009-F2010	2005 REAP • Application p3-24, 3-57 • BCUC IR #1.54.1, 1.54.2, 1.54.3, 1.54.4, 2.97.2 F05/F06 RRA (scope limited to capacity increase to G8 only) • Application p.11-12	$2.0 million (F2007 costs per 2005 REAP NSP)

The details of these projects in Definition Phase are included in Appendix I.

7.14.5 Identification Phase Projects

7.14.5.1 Campbell River Flood Control

Total Project Cost	Development Phase	Estimated In-Service	Previously Reviewed	UCA section 45(6.2)(b) Determination Sought
$115 million	Current - Identification; Plan to start Definition in F2007	F2011	No	$1.0 million (F2007 costs, per 2005 REAP NSP)

The Campbell River Development consists of a cascade of three dams: Strathcona, Ladore and John Hart with Strathcona as the uppermost dam. The Strathcona reservoir is the primary storage for the Campbell River Development and impounds Upper Campbell Lake

BCUC G-16-09

Project Name: G.M. Shrum Units 1 - 4 Generator Stator Replacement	
Forecast Capital Cost: Unit 1: $10 million to $16 million Units 2-4: $75 million	**In-Service Dates:** Unit 3 – F2008 Unit 4 – F2009 Unit 2 – F2010 Unit 1 – F2012
Development Phase: Implementation / Definition	**Filing Reference:** Refer to Next Page

Description:

G.M. Shrum Unit 1 to Unit 5, commissioned in the late 1960's, were manufactured by the same manufacturer and are of the same design.

The scope of this project is to replace up to four stators at the G.M. Shrum facility that are at risk of failure and where rewinding the stators is not technically feasible due to the condition of the cores. Refurbished generators will have an installed capacity of 305MW, a 44 MW increase from the existing capacity of 261MW.

The technical assessment has confirmed the need to replace Unit 2 to Unit 4 stators. The assessment of Unit 1 is still underway and a decision has not yet been finalized on the need to replace the Unit 1 stator.

Key Drivers:

- Reliability of supply (reduction in future unplanned outages)
- Minimize cost (forced outages can cost up to $3 million per month per unit, depending on when the outage occurs and outage duration)

Issues Being Addressed:

- The generator stators on all these units are prematurely aging. Inspections of the Unit 2, 3 and 4 stator cores show advanced signs of core waves, core fretting, and chevrons. Technical assessment concluded that these stators are at imminent risk of failure, with replacement the only feasible technical solution. The technical assessment of Unit 1 is still underway.

Discussion of Alternatives:

Since refurbishment and repair of the generator stators is not technically feasible, the only alternative evaluated in detail was the immediate vs. delayed replacement of the stators.

If the stator replacement project was delayed, BC Hydro would save the carrying cost of the capital investment in the new stators, but would be exposed to the risk of forced outage costs due to winding failures. The analysis showed that the optimal time to replace the first stator was in 2007 and the second in 2008. Any additional deferral will result in the expected risk of failure exceeding the expected benefit of deferral.

Additional Information:

In BC Hydro's F07/F08 RRA this project was shown as two projects:

- Units 3 and 4 – Implementation Phase - $46 million
- Units 1 and 2 – Definition Phase - $37 million

F07/F08 RRA APPENDIX L
Aberfeldie Redevelopment

1.7 Project Justification

Options of decommissioning, redevelopment and status quo operation were evaluated. Due to the age of the facility and the condition of most of the equipment, most components will require replacement in the near future (the woodstave pipeline is unsafe to operate beyond this winter). As such, the status quo alternative would involve replacement or maintenance of most of the existing facility; essentially redevelopment at 5 MW. Decommissioning would not avoid all ongoing costs, as it would not be economic to remove the existing dam from service, and would therefore require ongoing maintenance and surveillance costs with no corresponding electricity generation. Different sized redevelopment projects were analysed and based on the financial and sensitivity analysis performed and cost estimates the 24 MW option was preferred. The selected 24 MW size is the largest project with an incremental unit cost of energy below current market, and it therefore represents the most cost-effective redevelopment of the site. This was the basis of the original business case and the decision to proceed with redeveloping Aberfeldie.

Since the original business case was completed in 2004, extensive public consultation and negotiation has occurred with First Nations. All parties have agreed that potential impacted have been mitigated by BC Hydro's design and planned operations.

The project capital cost estimate has increased from $46 million (October 2004) to $65 million (February 2006). Despite the increase in cost, the Aberfeldie Redevelopment Project remains competitive with BC Hydro's other sources of new energy supply. The levelized unit energy cost based on the higher capital cost estimate is $47/MWh and $40/MWh, based on a 25 and 50 year economic life, respectively.

The supporting Implementation Phase business cases are attached:

- Schedule 1: Supplemental Business Case, Aberfeldie Redevelopment, Feb 2006. This supplemental business case is directed at the increase of the Aberfeldie Redevelopment Project from $46 million to $65 million (including dismantling). The major reasons for the cost increase are as follows:

1) Increase in the cost of major equipment supply contract as a result of bids received (+$8 million);

2) Increase in the anticipated cost of the civil construction contract due to the current construction boom (+$8.5 million).

- Schedule 2: Implementation Phase Business Case, Aberfeldie Redevelopment, October 2004.

1.8 Cost Impact

The Aberfeldie redevelopment will significantly impact the overall financial position of facility.

The analysis that follows is consistent with our analysis of all operational facilities in the fleet, including allocation of significant Generation-wide and Corporate costs. The analysis is presented over a 10 year period with related levelized cost of production calculations. Given the Aberfeldie redevelopment however, the time frame of evaluation does not fully reflect the economic justification of the project which has been presented and approved by the BC Hydro Board of Directors. The economic analysis, for example, evaluates the project over its expected useful life of 50 years and examines only incremental costs related to the investment and not allocated costs that in reality would not be impacted by the project proceeding. On the basis of the economic analysis, the 25 year and 50 year real levelized cost of production would equate to approximately $47/MWh and $40/MWh respectively.

The following evaluates Aberfeldie over a time period of 10 years to be consistent with information presented in the individual Facility Asset Plans and at a level of detail that would be difficult to meaningfully evaluate if we presented information over the expected life of the asset of approximately 50 years.

The financial structure of Aberfeldie, consistent with other assets in the generating fleet, is heavily influenced by significant fixed and allocated costs. Plant management has the largest influence on direct costs, which include maintenance, operations, general and administrative costs. Over the short-term, plant management has little control over

SCHEDULE 1 - FEB 2006
F07/F08 RRA

BChydro

ABERFELDIE REDEVELOPMENT PROJECT

PURPOSE

To review the increase in the capital cost for the Aberfeldie Redevelopment project and its implications on the project economics, and to seek approval of the additional funds required for completing the project.

OVERVIEW

In October of 2004, the Board of Directors approved a plan to redevelop the Aberfeldie generating station, a small plant located 30 km east of Cranbook, from 5 MW to 24 MW for a capital cost of $46 million (P50 level). The cost of power from the new facility was estimated to be between $36 and $40/MWh.

Since that time the capital cost of the project has been re-evaluated to reflect recently returned equipment supply tenders and current market conditions that will impact the civil construction costs. The new forecast for the capital cost is $65 million (P50 level). The resultant cost of power from the new facility is now estimated to be between $47 and $52/MWh utilizing a cost of capital consistent with the analysis presented in October 2004 of 8%, or between $40 and $47/MWh using a current expected cost of capital of 6.7%.

This summary provides a description of the current state of the project, an explanation of the capital cost increases, a discussion of project risks, and recommendation for continuing with the project as planned despite the increase in cost.

PROJECT UPDATE

The current state of the project development can be summarized as follows:

- All necessary studies and applications for permits have been completed and submitted to the appropriate government authorities. Issuance of the permits has not yet occurred and is pending the finalization of First Nation's consultation with the Ktunaxa Nation. This is expected to occur by the end of May 2006.
- The tender for the major equipment supply (generator, turbine, exciter, governor, protection and controls) was issued in October and [redacted] bids have been received and are being evaluated.
- The technical specifications for the civil construction tender are currently being prepared. The tender will be issued in late February 2006 following approval for the project to proceed, with bids expected by the end of April 2006.
- The April 2007 schedule for commercial operation has been pushed back to November 2007 to allow greater flexibility for construction contractors – hopefully increasing the number and quality of bids.

- Approximately $3.5 Million will have been spent on this project as of February 1, 2006.

PROJECT COSTS AND RISKS

The forecast cost increase over the October 2004 P50 budget estimate of $46 million is $19 million. The increase can be attributed to the items shown in the Table 1. Each of these items, and the remaining risks associated with each, is then discussed in greater detail below.

Table 1 – Cost Increase Categories

	Basis for Change in Estimate	Increase
Major Equipment Supply	Revised Pricing – Bids received	+$8M
Civil Construction Contract	Revised Pricing – Estimate based on recent construction bids for other projects	+$8.5M
Sediment Control Structure	Revised Scope – Based on finalizing engineering design	+$0.5M
BCTC Interconnection	Revised Scope – Based on BCTC Interconnection Study	+$1M
Other	Miscellaneous Items	+$1M
Total		+$19M

1. Major Equipment Supply Contract

The lowest bidder for the Aberfeldie equipment supply contract was the [redacted]. Their tendered base price to supply [redacted]. The [redacted] bid is about [redacted] higher than the original project estimate. This is due to escalating market conditions (suppliers are busy, and major component parts – such as metals – have increased in price considerably).

[redacted]. Before accepting the [redacted] bid, a thorough investigation of their technical capability, commercial viability, and social responsibility standards will be performed. At this stage there is a significant risk [redacted]. As such, an additional [redacted] has been incorporated into the project cost forecast.

2. Civil Construction Contract

Current construction market conditions have been found to be very unfavorable, due to the current construction boom. It is expected that the Aberfeldie civil construction contract will be much higher than the original estimate, which was based on the historic construction cost database. As a result, a market allowance of [redacted] was added to the

estimated civil construction costs to reflect the anticipated prices in the bids that will be submitted. The risk remains, however, that this market allowance will not be sufficient. This will not be known for sure until bids are received in April 2006.

3. Sediment Control Structure

   There is a trade-off between the cost of sediment removal from the water utilized and the cost of long-term turbine wear. In July 2005 a large-scale hydraulic model study was completed to optimize this relationship. The result is that a larger than anticipated sediment control structure is required, resulting in a cost increase of $0.5 million. A certain amount of runner wear and damage will likely still occur over the long term due to the nature of the source flow – however if the level of wear and damage is found to be unacceptably high then the plant will need to be retrofitted with a much more elaborate sediment control structure at a later date. The cost of such a structure could be $2-3 million, but has not been estimated in detail.

4. BCTC Interconnection

   With the existing Aberfeldie facility already in place it was initially believed that the interconnection cost of a new, larger facility would be minor. Subsequent to this a detailed interconnection study was completed by BCTC that indicated a much more complex connection and protection scheme was required. This new scheme added approximately $1 million to the cost forecast, however the actual cost to complete this work will not be certain until bids are received April 2006.

Table 2 shows the revised project costs (P50 and P90) as well as the Upper Bound cost, which represents the cost forecast if all of the major risks described above occur.

Table 2 – Revised Project Cost Estimate

Nominal Dollar Cost Estimate	October 2004 Estimate ($M)	December 2005 Estimate ($M)
P50 Cost Estimate	$46.0	$65.0
P90 Cost Estimate	$51.0	$68.0
Upper Bound Cost Estimate	Not Calculated	$70.0

FINANCIAL ANALYSIS

The financial analysis of the project has been updated in the context of increased capital costs as well current assumptions on energy generation based on equipment supplier negotiations and operating assumptions. A significant change from the previous analysis is the utilization of a cost of capital of 6.70% which represents a 100% debt long term borrowing rate. This change is a result of the view that in reality this project will be financed with 100% debt and no equity return will be generated from the project.

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER C-2-07

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Hydro and Power Authority
for the Aberfeldie Redevelopment Project

BEFORE: A.W.K. Anderson, Commissioner February 9, 2007

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. British Columbia Hydro and Power Authority's ("BC Hydro") F2007 and F2008 Revenue Requirements Application ("F07/F08 RRA") Negotiated Settlement Agreement issued November 6, 2006, did not include an agreement among the Parties that expenditures referred to in the F07/F08 RRA in regard to the Aberfeldie Redevelopment Project ("Aberfeldie Project") were, or were not, in the interests of persons within British Columbia who receive, or who may receive, service from BC Hydro; and

B. It was agreed that the Commission's current review of BC Hydro's proposed expenditures in regard to the Aberfeldie Project (initiated by the filing of the F07/F08 RRA) would continue and could, by Commission order, continue as an application for a Certificate of Public Convenience and Necessity ("CPCN"); and

C. By letter dated November 15, 2006 to the Commission, and copied to the Intervenors in the F07/F08 RRA process, BC Hydro advised that with the filing contained in that letter, it believed it had placed on the record, or identified, all information materially relevant to the Aberfeldie Project; and

D. By letter dated November 20, 2006, the Commission requested Intervenors in the F07/F08 RRA process to advise as to their positions as to whether more information was required regarding the Aberfeldie Project, and the process by which the application should proceed; and

E. The Commission received several letters from Intervenors in the F07/F08 RRA process regarding the Aberfeldie Project in response to the Commission's letter dated November 20, 2006; and

M. In a letter dated January 26, 2006 (Exhibit A-5), the Commission reaffirmed the process and the Regulatory Timetable established by Order No. G-149-06 that required the regulatory review of the Aberfeldie Project to continue through a CPCN application; and

N. The Commission has considered the Application and the evidence and submissions presented on the Application and has determined that it is in the public interest that a CPCN be issued to BC Hydro for the Aberfeldie Project subject to the directions set out in this Order.

NOW THEREFORE pursuant to Sections 45 and 46 of the Act the Commission orders as follows:

1. A Certificate of Public Convenience and Necessity is granted to BC Hydro for the Aberfeldie Project as described in the Application.

2. Following completion and placing into operation of the Aberfeldie Project, if BC Hydro seeks recovery of any costs associated with the Aberfeldie Project in excess of $94 million, it shall file evidence demonstrating why such expenditures were the result of causes beyond its control or were otherwise required to be incurred.

3. BC Hydro is directed to file with the Commission quarterly progress reports on the Aberfeldie Project schedule, costs, and any variances or difficulties that the project may be encountering, followed by a final report upon project completion. BC Hydro is to determine the form and content of the reports in consultation with Commission staff.

DATED at the City of Vancouver, in the Province of British Columbia, this 9th day of February 2007.

BY ORDER

Original signed by:

A.W.K. Anderson
Commissioner

F. By Order No. G-149-06 dated November 29, 2006 (Exhibit A-1), the Commission directed BC Hydro to submit an application by Wednesday, December 6, 2006 for a CPCN to redevelop the Aberfeldie Redevelopment Project and established the Regulatory Timetable for a written public hearing for the regulatory review of this application; and

G. By letter dated December 6, 2006 to the Commission (Exhibit B-5), BC Hydro applied for a CPCN in respect of the Aberfeldie Redevelopment Project (the "Application"); and

H. By letter dated December 18, 2006 to the Commission (Exhibit B-7), BC Hydro provided an estimate of certain incremental costs to the project as a result of the CPCN-related provisions of Order No. G-149-06; and

I. By letter dated December 20, 2006 (Exhibit C5-2), the Joint Industry Electricity Steering Committee ("JIESC") requested that the Commission and BC Hydro take action to prevent certain extra costs from being incurred; and

J. By letter dated December 22, 2006 (Exhibit B-8), BC Hydro stated it was supportive of an application to rescind those elements of Order No. G-149-06 (Exhibit A-1), that required the regulatory review of the Aberfeldie Project to proceed as a review of a CPCN application; and

K. In a letter dated December 22, 2006 (Exhibit A-4), the Commission requested written comments from participants regarding whether the Commission should rescind the elements of Order No. G-149-06 that require the regulatory review of the Aberfeldie Project to continue through a CPCN application, and proceed with the review of the Project pursuant to Sections 45(6.2)(a) and (b) of the Utilities Commission Act ("the Act"); and

L. The Commission received several communications from Intervenors (Exhibit C1-4, Exhibit C4-4, Exhibit C5-3, and Exhibit C6-2) in response to the Commission's letter dated December 20, 2006; and

BC hydro

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BCH_ ABERFELDIE PROJECT EXHIBIT B-1

November 7,2006

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

RE: British Columbia Utilities Commission (BCUC)
Project No. 3698416
British Columbia Hydro and Power Authority (BC Hydro)
F2007/F2008 Revenue Requirements Application (F07/F08 RRA)

BC Hydro writes to provide updated information on the Aberfeldie Generating Station redevelopment project (the Aberfeldie project).

As part of the F07/F08 RRA BC Hydro requested a BCUC determination under section 45(6.2) (b) of the *Utilities Commission Act* (UCA), that the expenditures on the Aberfeldie project are in the interests of persons within BC who receive, or who may receive, service from BC Hydro. This request was made in the context of BC Hydro's proposed capital plan review process, presented in the F07/F08 RRA.

At the time of filing the F07/F08 RRA the planned capital cost of the Aberfeldie project was $64 million, with an estimated in-service date of January 2008. In BC Hydro's Evidentiary Update, filed on August 31, 2006, the total capital cost estimate remained at $64 million, however the expected in-service date was delayed from F2008 until F2009. This had the effect of deferring $64 million of capital additions from F2008 to F2009.

In BC Hydro's response to BCUC IR 3.11.3 (Exhibit B-18) filed on September 7, 2006 BC Hydro stated that "BC Hydro has staged its activities associated with the Aberfeldie Redevelopment project to ensure that the commitment to the project is informed by the status of approvals, consent, contract pricing for generating equipment and civil work that can support detailed cost and schedule estimate. At this point, based on the outcome of the tenders and the resulting updated cost and schedule estimates and consistent with the approach to stage the decisions and ultimate commitment to the Aberfeldie project, BC Hydro will revisit options including decommissioning." Essentially BC Hydro was indicating that it was reviewing and updating its cost estimates for the project, and was not in a position, at that time, to provide any further details on costs or schedules.

In the F07/F08 RRA Negotiated Settlement Agreement (NSA), submitted to the Commission panel for approval on November 6, 2006, it is noted at section 5 that the Settlement Agreement is a comprehensive settlement of all issues arising from the

F07/F08 RRA, except for the determination sought by BC Hydro in respect of the Aberfeldie project. It was agreed by all parties to the NSA that the Commission's current review of the expenditures in relation to Aberfeldie will continue, despite any order approving the NSA.

It is in this context that BC Hydro is submitting updated information on the Aberfeldie project, in order to keep the Commission and intervenors appraised of the status of the project, with the intent of continuing the review in an efficient and timely manner, consistent with that achieved through the F07/F08 RRA Negotiated Settlement Process (NSP).

On November 2, 2006, updated cost estimates, project schedule and evaluation for the Aberfeldie project were presented to the BC Hydro Board at its quarterly Board meeting. These costs estimates and schedule were based on the receipt and review of tenders for generating equipment and civil services. The cost estimate for the project submitted to the Board was $83 million, with an upper bound estimate of $94 million, and an expected in-service date of late fall 2008. The BC Hydro Board gave its approval to proceed with the execution of the major contracts and commence project implementation.

The escalation in estimated costs experienced during the definition stage of the Aberfeldie project are in part due to the rising construction costs currently being experienced in BC. The most recent estimates were informed by actual contract pricing. However despite the increase in the project cost BC Hydro remains of the view that the Aberfeldie project is competitive with other sources of new energy supply for BC Hydro. The redevelopment enables a near term supply addition, with executable contracts, permitting and water use plans in place. Given the fact that the condition of the wood stave penstock has now forced the plant to be shut down for this winter, and that equipment and civil contract execution enables over 75 per cent of the direct project costs to be locked down, mitigating the risk of further cost escalation, BC Hydro considers that proceeding with the project at this time is the most prudent course of action.

BC Hydro recognizes that the practical and commercial realities of the Aberfeldie project have coincided with the timing of the regulatory review process. The Aberfeldie project has been in its investigation and definition phases for some time (since the early 2000's), and given the staging of various activities, has taken longer to proceed to implementation phase than initially envisaged. In the mean time BC Hydro has come forward with its proposed capital plan review process for threshold projects, effectively catching the Aberfeldie project already well advanced when the review process was proposed. Nevertheless, BC Hydro is continuing to request a determination on this project, and, conscious of its contractual commitments, seeks an efficient and timely review process.

BC Hydro expects to file, within the next week, the updated business case for the Aberfeldie project, including accompanying materials such as contract details, water use plans, design scope and permits. At that time BC Hydro expects to propose a continuation of the NSP, subject to intervenor comments, mindful of the fact that were it

not for the later timing of the finalization of the updated business case and the Board approval, that this request for a determination could have been addressed through the NSP in October 2006.

Yours sincerely,

Joanna Sofield
Chief Regulatory Officer

Enclosure

c. Project 3698416 Intervenors

Project Name: G.M. Shrum Units 1 to 5 Turbine Replacement	
Forecast Capital Cost: $246.9 million to $313.9 million	**In-Service Dates**: F2016
Development Phase: Implementation	**Filing Reference:** 2006 IEP – LTAP: • BCUC IR 1.284.1, Attachment 1 • TGI IR 2.2.1 Attachment 4 F07/F08 RRA: • Application, page 7-66, page 7-81, Appendix I • BCUC IR 1.5.1 Attachment 5 • BCOAPO IR 2.1.0 Attachments 1 and 2 • BCUC IR 2.347.00 Attachment 1 F09/F10 RRA: • BCUC IRs 1.66.1, 2.127.1, 2.161.1, 2.161.3 G.M. Shrum Units 1 to 5 Turbine Replacement Project Application and BCUC Order No. G-1-10 and Reasons for Decision F11 RRA: • Application page 6-13 Appendix I, page 1, Appendix J, page 1 • BCUC IRs 1.5.1 to 1.5.1.3, 1.181.1, 1.331.1 (Attachment 2), 2.406.4, 2.457.1, 2.515.1, 2.545.5 (Attachment 1) • BCOAPO IR 1.39.1

Description:
This Project involves replacing the GM Shrum Units 1 to 5 turbines. Specifically, this will involve designing and manufacturing new turbine runners, wicket gates, wicket gate operating mechanisms and head covers and overhauling the remaining turbine components. The expected service life of the new equipment is 50 years. The expected life extension of the overhauled components will be either 25 or 50 years depending on the component.

Key Drivers:
- Reliability (Supply) (mitigation of runner failure risk)
- Energy Security (Supply) (increased capacity)

Issues Being Addressed:
The primary justification for the Project is the unsatisfactory condition of the GM Shrum Units 1 to 5 turbines and the associated high business risks.
Cracks in the runners were discovered in 1972 and have been an ongoing problem since this time. BC Hydro has studied the cracking issue extensively and has concluded that it is due to inherent original design weaknesses including high dynamic stresses, low fatigue strength, defects in original manufacturing, and defects and stresses introduced by multiple weld-repairs. In addition, GM Shrum Units 1 to 5 turbines have a history of headcover cracking problem and the wicket gate operating mechanism has an inherent design problem that can contribute to cascading closure of de-synchronized wicket gates.
Replacing the turbines is expected to provide efficiency gains as a result of a new runner design, an improved surface finish and from water passage modifications outside the runners. The expected average annual efficiency gain is 35.4 GWh per unit or 177 GWh for all five units.

Discussion of Alternatives:
Rehabilitation was considered as an alternative to turbine replacement, but would not deliver the equipment longevity or efficiency gains anticipated by carrying out the Project.

EXHIBIT H-3

Additional Information:
On January 5, 2010, the BCUC issued its Order No. G-1-10 within which it found the Project to be in the public interest and accepted the capital expenditures schedule having a Project Expected Cost estimate of $262.0 million.

Project Name: Mica SF_6 Gas Insulated Switchgear (GIS) Replacement Project	
Forecast Capital Cost: $180.6 million to $200.2 million	**In-Service Date:** F2014
Development Phase: Implementation	**Filing Reference:** F09/F10 RRA, Appendix J, page 36, Mica GIS Application dated August 5, 2009, F11 RRA: • Appendix page 6-13, Appendix I, page 1, Appendix J, page 2, • BCUC 1.5.1 – 1.5.1.3, 1.145.1, 1.181.1, 1.199.2, 1.331.1 (Attachment 2), 2.406.4, 2.515.1, 2.545.5 (Attachment 1), 3.608.2; • BCOAPO 1.39.1

Description:
This project is to replace the existing 500 kV SF_6 GIS switchgear system at the Mica Generating Station and install additional SF_6 GIS necessary to accommodate the future addition of Mica Units 5 and 6. When completed the system will use three 500 kV circuits to conduct the energy from the Mica underground powerhouse to the surface, where it transitions to transmission system. Replacement of the existing switchgear system will maintain the level of reliability of this key generating station and have the additional benefit of reducing SF_6 (a greenhouse gas) leakage. The new switchgear system will also accommodate the future addition of the Mica Units 5and 6 generators.

Key Drivers:
- Reliability(Supply)
- Environment

Issues Being Addressed:
The Mica SF_6 GIS bus was installed in 1976 and is one of the earliest examples world-wide of such a system. Three different evaluations in recent years, completed by different international experts, recommend that BC Hydro replace the SF_6 GIS. The existing GIS presents a substantial risk of forced outages to BC Hydro and its replacement will mitigate this risk of forced outages

SF_6 gas is now known as a potent greenhouse gas. Since the equipment was first commissioned, leakage of SF_6 gas has been an issue. While maintenance over the past 30 years has greatly reduced the rate of leakage, more gas escapes from the Mica SF_6 bus than any other BC Hydro installation. Replacement of the bus will dramatically reduce SF_6 gas leakage.

Additional Information:
BC Hydro filed an application with the BCUC in August 2009. On March 16, 2010, the BCUC issued Order No. G-38-10 which determined that the Mica GIS Project was not in the public interest based on concerns regarding portions of the Project would be stranded if the Mica Units 5 and 6 project did not proceed.
On May 20, 2010, the BC Hydro Board of Directors approved full implementation funding for Mica Units 5 and 6. Subsequently, the *Clean Energy Act* (**CEA**) exempted various projects, including Mica Units 5 and 6, from sections 45 to 47 and 71 of the *Utilities Commission Act* (**UCA**).
With the implementation of Mica Unit 5 and 6, the concerns expressed in the BCUC decision regarding portions of the Project being stranded are minimized.

EXHIBIT H-4

Project Name: Stave Falls Spillway Gate Replacement	
Forecast Capital Cost: $66.9 million to $71.8 million	**In-Service Date:** F2013
	Filing Reference: • 2006 IEP – LTAP: • BCOAPO IR 1.58.2 F07/F08 RRA: • Application: page 7-84 • BCUC IR 1.5.1 • BCUC IR 1.5.1 Attachment 1 • BCOAPO IR 1.58.2 F09/F10 RRA: • Application: Appendix I, pages 1, 2; Appendix J, page 48 Stave Falls Spillway Gates Replacement Project Application BCUC Order No. G-81-10.
Development Phase: Implementation	F11 RRA: • Application: page 6-15, Appendix I, page 3, Appendix J, page 42 • Application: page 6-15, Appendix I, page 3, Appendix J, page 40 • BCUC IRs 1.181.1, 1.192.2, 1.192.3, 1.197.1, 1.197.2, 1.200.1, 1.200.2, 1.230.2 Attachment 1, 1.253.3, 1.257.1, 1.261.1 Attachments 1 and 4, 1.265.1 Attachment 1, 1.298.3 Attachment 1, 1.331.1 Attachment 1 and 2, 3.608.2, 3.652.2, 3.673.1, 3.673.1.1, 3.673.1.2, 3.673.1.3, 3.673.2, 3.673.3, 2.406.3, 2.461.1, 2.481.1, 2.495.2, 2.496.3 Attachment 1, 2.545.5 Attachment 1, 2.552.2; • JIESC IR 1.12.4 Confidential Attachment 1, 1.12.4 Attachment 1, 2.24.4 Attachment 6 and 7; • BCOAPO IR 1.39.1.

EXHIBIT H-5

Description:
In 2006, BC Hydro began an initiative to improve equipment and procedures to ensure that the spillway gates at BC Hydro sites will operate when required. The general civil works scope of work is the replacement or refurbishment of the discharge facilities such as reinforcement of gate hoists and towers, upgrade of the electrical power supply and redundancy incorporated into the system. The scope of work varies with location. Non-civil works include changes to maintenance, inspection and testing procedures, primarily frequency, scope and training.

The primary goal is to upgrade BC Hydro's spillway gate systems to reduce dam safety risk using the Reliability Principles. BC Hydro's Reliability Principles for Flood Discharge Gate Systems establish targets for the probability of failure on demand of those systems during severe floods. For Extreme, Very High, and High Consequence dams, this target is in the order of 1 in 1,000 to 1 in 10,000. These targets drive designs that incorporate redundancy, segregation, robust features and include complimentary inspection, maintenance and testing programs.

This dam site is a high priority site because of the condition of the equipment and high consequences to the dam and surrounding areas if the gates should fail to open when required and overtopping occurs.

Key Drivers:
- Safety (Employee and Public)
- Reliability (Supply)

Issues Being Addressed:
- There is a high risk that the flood discharge gates at Stave Falls will fail to operate when required so the following work will be carried out:
  - Four radial gates will be replaced;
  - Hoists will be replaced with new hoists;
  - Electrical power supply will be upgraded and redundancy incorporated into the system;
  - Upgrade of the fire protection.

Discussion of Alternatives:
i) Status quo/Do nothing – This alternative was not considered acceptable because of the risks associated with the condition of the spillway gates and failure to operate when required are considered too high.
ii) Flood Discharge Gate Reliability Upgrade. This is the recommended alternative. This project will ensure that the spillway gates will operate when required to prevent overtopping the dam.

Additional Information:
On May 13, 2010 the BCUC issued Order No. G-81-10 finding the Expected Cost of the Project, $61.5 million, to be in the public interest.

Project Name: Upper Columbia Capacity Additions at Mica – Units 5 and 6	
Forecast Capital Cost: $700.0 million to $800.0 million	**In-Service Date:** Unit 5 - F2015 Unit 6 - F2016
Development Phase: Implementation	**Filing Reference:** 2008 LTAP: • Exhibit B-1, section 6.2.4 F11 RRA, • Application, page 6-12, Appendix I, page 4, Appendix J, page 64 • BCUC IRs 1.181.1, 1.217.1 Attachment 6, 1.257.1, 1.261.1 Attachment 5, 1.269.1 Confidential Attachment 1, 1.269.1 Attachment 1, 1.285.6, 1.331.1 Attachment 1 and 2, 2.401.1 Attachment 1, 2.406.4, 2.449.1 – 2.449.3, 2.515.1, 2.545.5 Attachment 1, 2.546.2, 2.571.1, 2.599.3, 3.630.1, 3.630.2, 3.631.1

Description:

Mica Generating Station is BC Hydro's third largest generating facility. Built in the 1970's the plant was built with four large hydroelectric generating units but with bays for two additional 500 MW units.

The Mica Units 5 and 6 project involves installation of generating units similar to the four existing units but with more efficient turbines. In addition, there is a transmission requirement for a series capacitor station which would be located near the mid point on the existing Mica-Nicola 500 kV transmission lines.

Key Drivers:
Electricity Security (Supply) (Future capacity requirements – BC Hydro's least cost and most substantial resources available to meet future customer dependable capacity requirements).

Issues Being Addressed:

In BC Hydro's 2008 Long-Term Acquisition Plan (**LTAP**), the Base Resource Plan (**BRP**) identified the need for Mica Unit 5 in October 2024 and identified actions required in order for BC Hydro to meet its current and future customers' electricity need on a reliable and cost-effective basis. The LTAP Contingency Resource Plan (**CRP**) identifies the earliest date when Mica Units 5 and 6 may be required to reliably meet the peak demand of BC Hydro customers. The LTAP CRP date is October 2013 for Mica Unit 5 and October 2015 for Mica Unit 6.

Additional Information:
As part of the 2008 LTAP review process, the BCUC issued Order No. G-69-09 within which the BCUC determined that $30 million in expenditures over the period F2009 – F2011 in order to undertake and complete definition phase work for Mica Units 5 and 6 is in the public interest.
On May 20, 2010, the BC Hydro Board of Directors approved full implementation funding for Mica Units 5 and 6. Subsequently, the CEA exempted various projects, including Mica Units 5 and 6, from sections 45 to 47 and 71 of the UCA.

EXHIBIT H-6

Attachment to Appendix I

Explanation of the Differences

Generation

Note G1 - The Total Project Cost for the Cheakamus Penstock Inlet Valve & Controls Refurbishment, which is in implementation phase, is now forecast to be $1 million, $2.5 million or 73 per cent less than previously reported. This is primarily due to the control system upgrade element of the project being completed as part of the Cheakamus Penstock Inlet Valve Control System Upgrade Project.

Note G2 - The Total Project Cost for the G.M. Shrum Unit 6 and Unit 7 Rotor Pole Replacement, which is in implementation phase, is now forecast to be $10.8 million, $3.2 million or 23 per cent less than previously forecast. This is primarily due to anticipated cost savings from material supplies, services and labour.

Note G3 - The Total Project Cost for the G.M. Shrum DC System & Unit Protection Upgrade, which is in implementation phase, is now forecast to be $10 million, $4.2 million or 30 per cent less than previously reported. This is primarily due to realized and expected savings from doing multiple, identical installations. Additionally, scope was reduced in the project to remove upgrades to the station service protection.

Note G4 - The Total Project Cost for the Hugh Keenleyside Spillway Gate Reliability Upgrade, which is in implementation phase, is now forecast to be $102.5 million, $10.5 million or 11 per cent more than the higher previous forecast of $92 million. This is primarily due to increased scope and costs of the spillway gate subsystems. Supply and installation of the gates and hoists increased by approximately $7 million and there was an additional $8 million increase related to the supply and installation of the electrical power systems. This $15 million increase in costs is offset by a net $4.5 million reduction in indirect costs, contingency and project reserve. In November 2010 the BCUC, in Order No. G-177-10, found the expected cost of the

EXHIBIT H-7

project of $90.2 million to be in the public interest. This amount excludes the expensing of remaining net book value of $0.5 million, which is included in total project costs.

Note G5 - The Total Project Cost for the Spillway Gates Reliability Program - Reservoir Pilot Level Monitoring, which is in implementation phase, is now forecast to be $6.6 million, $2.5 million or 61 per cent more than previously reported. The increased cost is primarily due to increased scope and costs identified as the designs progressed from preliminary to final detailed designs. The key elements contributing to the increased cost includes additional management and engineering effort as well as more substantial infrastructure upgrades required to satisfy reliability requirements plus higher than expected cost of the redundant satellite communications path contract.

Note G6 - The Total Project Cost for the Strathcona Intake Tower Seismic Upgrade, which is in the implementation phase, is now forecast to be $28.5 million, $10.6 million or 27 per cent less than previously forecast. This is due to the fact that competitively tendered prices were lower than anticipated, and the contingencies provided for procurement, site conditions and contractor performance were not required to achieve the planned work.

Note G7 – The Lake Buntzen Turbine Inlet Valve and Controls Rehabilitation Project is in the early definition stage, and a recommended alternative from the many available for this project has not yet been chosen. Therefore, the current estimate of $4 million is still preliminary.

Note G8 - The Total Project Cost for the Revelstoke Unit 5 Installation, which is in implementation phase, is now forecast to be $250 million, $30 million or 11 per cent less than previously forecast. This is primarily due to the escalation allowance included in the cost estimate for the project that was not called upon during implementation.

Note G9 - The Total Project Cost for the Burrard Asbestos Management Program, which is in implementation phase, is now forecast to be $20.4 million, $3.9 million or

Project Name: Hugh Keenleyside Spillway Gate Reliability Upgrade	
Forecast Capital Cost: $90.7 million to $102.5 million	**In-Service Date:** F2014
	Filing Reference: 2006 IEP – LTAP: • BCOAPO IR 1.58.2 F07/F08 RRA: • Application: page 7-84 • BCUC IR 1.5.1 • BCUC IR 1.5.1 Attachment 1 • BCOAPO IR 1.58.2 F09/F10 RRA: • Application: Appendix I, pages 1, 2; Appendix J, page 48 • BCUC IRs 1.5.1, 1.193.0, • BCUC IRs 2.341.1, 2.343.0, 2.344.0, 2.347.0, • BCOAPO IRs 2.1.0, 2.2.1,
Development Phase: Implementation	Hugh Keenleyside Spillway Gates Project Application BCUC Order No. G-177-10 and Reasons for Decision F11 RRA: • Application: page 6-15, Appendix I, page 3, Appendix J, page 40 • BCUC IRs 1.181.1, 1.192.2, 1.192.3, 1.197.1, 1.197.2, 1.200.1, 1.200.2, 1.230.2 Attachment 1, 1.253.3, 1.257.1, 1.261.1 Attachments 1 and 4, 1.265.1 Attachment 1, 1.298.3 Attachment 1, 1.331.1 Attachment 1 and 2, 3.608.2, 3.652.2, 3.673.1, 3.673.1.1, 3.673.1.2, 3.673.1.3, 3.673.2, 3.673.3, 2.406.3, 2.461.1, 2.481.1, 2.495.2, 2.496.3 Attachment 1, 2.545.5 Attachment 1, 2.552.2; • JIESC IRs 1.12.4 Confidential Attachment 1, 1.12.4 Attachment 1, 2.24.4 Attachment 6 and 7; • BCOAPO IR 1.39.1.

Project Name: Ruskin Dam Safety and Powerhouse Upgrade	
Forecast Capital Cost: 728.6 to 867.4 million	**In-Service Date:** F2018
Development Phase: Definition	**Filing Reference:** **<u>Ruskin Dam Safety Improvement Project</u>** 2006 IEP – LTAP: • BCUC IR 3.28.1 F07/F08 RRA: • Application: Appendix K • BCUC IR 1.5.1 • BCOAPO IR 2.1.0 Attachment 2 • BCUC IR 2.341.1 Attachment 1 • BCUC IR 2.344.0 **<u>Ruskin Generating Station Redevelopment Project</u>** F07/F08 RRA: • Application: Appendix K • BCOAPO IR 2.1.0 Attachment 2 F09/F10 RRA: • Application: Appendix I, page 1; Appendix J, page 43 • BCUC IRs 2.161.1, 2.161.3 F11 RRA: • Application: page 6-13, Appendix I, page 2, Appendix J, page 34 • BCUC IRs 1.257.1, 1.285.6, 1.331.1 Attachment 1, 2.401.1 Attachment 1, 2.406.4, 2.545.5 Attachment 1

EXHIBIT H-8

Description:
The 105 MW Ruskin Dam and Generating Station (Powerhouse and Unit 1) were originally commissioned in 1930 (81 years ago). The second and third generating units were installed in 1938 and 1950 respectively and no substantial upgrades or modifications to the Ruskin Powerhouse have been made since the third generating unit was added in 1950.
The upper dam and right abutment have been assessed as having a low seismic withstand capability relative to other BC Hydro facilities and current seismic standards. The right abutment has been observed to have excessive seepage, raising the risk of piping and uncontrolled release of the reservoir. With respect to the Powerhouse, much of the equipment is in poor or unsatisfactory condition resulting in decreased reliability and reduced availability, which increases the risk of flow interruptions that could adversely impact fish habitat.
The Project entails the replacement of parts of the seismically deficient Dam and the rehabilitation/replacement of the 105 MW Ruskin Powerhouse, including generating equipment brought into service between 1930 and 1950, and associated transmission infrastructure. The Project has two main components:
The Dam upgrade entails measures to address the seismic/safety deficiencies of parts of the Dam: (1) replacement of the spillway piers and spillway gates; rehabilitation of the spillway surface; replacement of the roadway crossing the top of the Dam; (2) anchoring and reinforcing sections of the existing Right Abutment and construction of a new seepage cut-off wall at the Right Abutment; and (3) reduce the slope and install a filter blanket and monitoring instrumentation at the Left Abutment.
The Powerhouse rehabilitation/replacement includes: (1) seismic upgrades to the Powerhouse superstructure and substructure; rehabilitation/replacement of the three generating units, electrical and mechanical equipment, and ancillary systems; rehabilitation of water conveyance components (draft tubes, penstocks and intakes); replacement of step-up transformers; and (2) upgrade and relocation of the switchyard from the roof of the existing Powerhouse to an area above the Powerhouse.
The Ruskin Dam and Powerhouse Project, currently in Definition Phase, has been initiated to address these concerns. In February 2011, BC Hydro's Board of Directors approved an Authorized Amount of $856.9 million (plus an additional $10.5 million in asset retirement costs) for the Ruskin Project. The Ruskin Project is expected to be put into service in stages over the fiscal years F2014 to F2018. On February 22, 2011, BC Hydro submitted a separate application with the BCUC seeking a **CPCN** for the Ruskin Project.

Key Drivers:
- Safety (public and employee safety)
- Reliability (Supply)
- Environmental

Issues Being Addressed:
Dam Safety Improvement
The primary issues being addressed are the unacceptable risks associated with the condition of the seismic stability of the upper dam and spillway operational reliability, as well as the static and seismic deficiencies in the right abutment.
Generating Station Redevelopment
The condition of most of the major generator station equipment is in "poor" or "unsatisfactory" condition and requires significant capital expenditures to support safe and reliable operation and the powerhouse does not meet current seismic standards. In addition, a unit or station failures can interrupt the flow of water downstream into the lower Stave River, which may endangering fish habitat below the dam. Use of the spillway can also increase the total gas pressure in the lower Stave River beyond acceptable limits. Improved unit reliability will reduce both de-watering and total gas pressure risks to the lower Stave River.

Discussion of Alternatives:
In addition to the proposed rehabilitation option, the following five alternatives have been considered:

i. Permanently De-Rate Two Generating Units, Remove the Third Generating Unit - The spillway gates would be removed and small automated crest gates installed on the Dam crest to provide enough spill capability to ensure that a plant trip does not dewater the lower Stave River. The reservoir elevation would be maintained at approximately 37 m. At this reservoir elevation Unit 3 is inoperable. Unit 3 and ancillary equipment would be removed while the other two units and their ancillary equipment would be replaced in the same way as contemplated in the Project. These two remaining generating units would provide less energy and capacity than two of the current Ruskin Facility units due to the reduced available head.

ii. Abandon with Overflow - The spillway gates would be removed and flashboards installed on the crest of the five interior spillway bays. As for Alternative i), this reduces the consequence of a failure of the spillway piers. The Powerhouse would be removed down to the generator floor and new discharge valves would be installed in a newly-constructed valve-house. These valves would be sized to allow the Unit 1 and Unit 2 penstocks to pass the normal flow of approximately 100 m^3/s into the Unit 1 and Unit 2 draft tubes. The Unit 3 penstock would be filled with gravel and capped with concrete at both ends, as would the U3 draft tube.

iii. Abandon and Dam Removal - The Dam would be removed and the Hayward Lake Reservoir would be returned, to the extent practicable, to its original condition. The Powerhouse would be removed to the generator floor, and all three penstocks would be filled with gravel and capped with concrete at both ends, as would all three draft tubes. This alternative would require dewatering Hayward Lake Reservoir prior to removal of the Dam.

iv. Abandon without Dam Removal - This alternative is similar to iii); rather than removing the Dam, a large opening would be cut through the base of the Dam to allow water passage.

v. Permanently De-Rate all Generating Units and perform Intake Modifications - As in Alternative i), the spillway gates would be removed and small automated crest gates installed on the Dam crest. As for Alternatives i) and ii), this reduces the consequence of a failure of the spillway piers. The reservoir elevation would be maintained at approximately 37 m. To continue the use of Unit 3, the intake would be modified so that the intake is lowered to the same elevation as the other two units. The Powerhouse rehabilitation would be substantially similar to that contemplated in the Project, leaving the facility with three operating units but with a reduced hydraulic head.

BC Hydro has concluded that while the Project has the highest capital cost, it is the most cost-effective as it provides the greatest energy and capacity. The value of the energy and capacity of the Project compensates for the increased capital cost: the Project has the highest NPV compared to the alternatives and provides the lowest UEC. Both the Project and the de-rating alternatives are competitive with IPP energy purchases as measured by the Clean Power Call results.

Additional Information:
For further information on this project, refer to BC Hydro's Ruskin Dam and Powerhouse Upgrade CPCN Application, which was filed with the BCUC on February 22, 2011.

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER C-5-12

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Application by British Columbia Hydro and Power Authority
for a Certificate of Public Convenience and Necessity
to Construct and Operate the Ruskin Dam and Powerhouse Upgrade Project

BEFORE: M.R. Harle, Panel Chair/Commissioner
N.E. MacMurchy, Commissioner
A.W.K. Anderson, Commissioner

March 30, 2012

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. On February 22, 2011, British Columbia Hydro and Power Authority (BC Hydro) filed pursuant to section 46(1) of the *Utilities Commission Act* (the Act), an application for a Certificate of Public Convenience and Necessity (CPCN) to construct and operate the Ruskin Dam and Powerhouse Upgrade Project (the Project) as described in the Application;

B. The Project is located at the existing Ruskin Dam and Generating Station (Ruskin Facility) located on the Stave River in the District of Mission. The Ruskin Facility was originally constructed in 1930, and has seismic and static deficiencies which require remediation to mitigate public and employee safety, financial and environmental risks. The age and condition of the existing units at the Ruskin Facility represent a significant and increasing risk to reliability;

C. The Project has an Expected Amount of $718.10 million that includes costs to date;

D. The Project has two main components:

(i) the Dam upgrade entails measures to address the seismic/safety deficiencies of parts of the Dam, namely: the replacement of the spillway piers and spillway gates, rehabilitation of the spillway surface, replacement of the roadway crossing the top of the Dam, anchoring and reinforcement of sections of the existing Right Abutment and construction of a new seepage cut-off wall at the Right Abutment and construction of a new seepage cut-off wall at the Right Abutment, and reducing the slope and installing a filer blanket and monitoring instrumentation at the Left Abutment, and

(ii) the Powerhouse upgrade includes seismic upgrades to the Powerhouse structure, rehabilitation/replacement of the three generating units, electrical and mechanical systems, rehabilitation of water conveyancing components, replacement of step-up transformers, and an upgrade and relocation of the Switchyard currently located on the roof of the existing Powerhouse to an area above the Powerhouse.

The Project has a target Completion Date of March 2018;

E. By Order G-34-11 dated February 24, 2011, the British Columbia Utilities Commission (Commission) established a Written Public Hearing process for the review of the Application having two rounds of Information Requests according to the Regulatory Timetable as set out in Appendix A to that Order;

F. BC Hydro held a Workshop on the Application on February 28, 2011, at the Commission Hearing Room, 12th Floor, 1125 Howe Street in Vancouver, BC;

G. By letter dated March 29, 2011, BC Hydro applied for a revision to the Regulatory Timetable to:

- provide BC Hydro additional time to respond to the large number of Intervener Information Requests (IRs);
- allow more time for Interveners to review the Application; and
- schedule an informal Ruskin site visit for Commission staff and Interveners;

H. BC Hydro circulated a draft copy of the proposed changes to the Regulatory Timetable to all Interveners registered for the Proceeding on Friday, March 25, 2011, and no Intervener raised any concerns;

I. By Order G-65-11 dated March 31, 2011, the Commission approved BC Hydro's request for a revised Regulatory Timetable as set out in Appendix A to that Order;

J. By letter dated April 21, 2011, the Commission received a request from counsel for the Kwantlen First Nation (Kwantlen) to amend the Regulatory Timetable to extend the date for filing Intervener Evidence. The letter further stated Kwantlen's counsel had canvassed BC Hydro and Interveners and no concerns were raised;

K. By Order G-76-11 dated May 4, 2011, the Commission approved the Kwantlen First Nation's request for a revised Regulatory Timetable as set out in Appendix A to that Order;

L. By letter dated June 23, 2011, BC Hydro requested an amendment to the Regulatory Timetable in order to narrow Project-related issues through further dialogue with the Kwantlen First Nation. BC Hydro heard no objections to the proposed amendment from Interveners;

M. By Order G-116-11 dated June 30, 2011, the Commission approved BC Hydro's request to amend the Regulatory Timetable as set out in Appendix A to that Order;

N. By letter dated September 2, 2011, BC Hydro requested an amendment to the Regulatory Timetable:

- to permit a round of IRs from the Commission and Interveners to test BC Hydro's Evidentiary Update, which was submitted in response to the June 2011 Government panel report entitled "Review of BC Hydro";
- to test BC Hydro's rebuttal evidence addressing aspects of Kwantlen First Nation's evidence submitted on July 29;
- to extend the time to respond to a Commission information request for further clarification.

In this same letter, BC Hydro revised its request for the CPCN to be issued on the basis of an Expected Amount of $728.6 million, and not the originally requested Authorized Amount of $856.9 million.

BC Hydro canvassed and heard no objections to the proposed amendment from Interveners;

O By Order G-159-11 dated September 14, 2011, the Commission approved BC Hydro's request to amend the Regulatory Timetable as set out in Appendix A to that Order;

P. By letter dated September 26, 2011, BC Hydro advised that the Procedural Conference placeholder was not required. By letter dated September 27, 2011, the Commission determined that the Procedural Conference was not warranted and the review of the Application would proceed in accordance with the Regulatory Timetable as per Appendix A to Order G-159-11;

Q. By letter dated January 3, 2012, the Commission received a request from counsel for the Kwantlen First Nation seeking leave to file limited submissions in response to the reply argument filed by BC Hydro (Sur-Reply);

R. By letter dated January 5, 2012, BC Hydro stated its view that although the Kwantlen failed to justify its Sur-Reply, BC Hydro will not oppose the Kwantlen Sur-Reply application provided that BC Hydro is afforded the opportunity to reply to the Kwantlen Sur-Reply by January 11, 2012;

BC Hydro shared a draft copy of this letter with the Association of Major Power Consumers of B.C. (AMPC), British Columbia Old Age Pensioners' Organization (BCOAPO) and the Commercial Energy Consumers Association of BC (CEC) because all three of these customer interveners took a position on the adequacy of consultation with Kwantlen and recommended these groups be given an opportunity to make submissions with respect to the Kwantlen Sur-Reply. BC Hydro copied its letter to all registered Interveners;

S. By letter dated January 5, 2012, the Commission granted the Kwantlen leave to file its Sur-Reply and established deadlines for AMPC, BCOAPO and the CEC to submit responses to the Sur-Reply by January 9, 2012, and BC Hydro to provide its reply by January 11, 2012;

T. Responses were received on the subject of the Sur-Reply by letter from AMPC, CEC and BC Hydro by the due dates;

U. On February 2, 2012, the BC Government enacted amendments (Amendments) to: (1) the Electricity Self-Sufficiency Regulation issued under the *Clean Energy Act*, and (2) Special Direction No. 10 to the British Columbia Utilities Commission (Amended SD 10) issued under the *Utilities Commission Act*;

V. By letter dated February 8, 2012, BC Hydro submitted its view of the effect of these Amendments on the Project-related CPCN public interest test, and suggested a process for Interveners to provide their submissions and for BC Hydro to reply to those submissions;

W. By letter dated February 9, 2012, the Commission wrote to registered Interverners accepting BC Hydro's proposed process for review of the Amendments;

X. Interverners submitted their views on the effect of the Amendments by February 13, 2012, and BC Hydro replied to those views by February 15, 2012, in accordance with the Commission's due dates.

Y. The Commission has reviewed and considered the Application, the evidence and the submissions presented on the Application, and has determined, as set out in the Decision issued concurrently with this Order, that the Project is in the public interest and that a CPCN should be issued to BC Hydro for the Project, subject to the conditions and directions set out in this Order.

NOW THEREFORE the Commission orders as follows:

1. A CPCN is granted to BC Hydro for the Project as set out in the Application.

2. BC Hydro is directed to file with the Commission semi-annual progress reports on the Project schedule, costs with a comparison to the Expected Amount set out in the Application and any variances or difficulties that the Project may be encountering. The form and content of the semi-annual progress reports will be consistent with other BC Hydro capital project progress reports filed with the Commission. The semi-annual progress reports will be filed within 45 days of the end of each reporting period.

3. BC Hydro is directed to reflect in its semi-annual progress reports on the Project that the Commission has approved only a Basic Expected Amount of $640.6 million, which excludes Capital Overhead (COH). This amount is to be supplemented in the future as COH rates are approved by the Commission from time to time in its decisions on BC Hydro's Revenue Requirement Applications, to arrive at a Total Expected Amount.

4. BC Hydro is directed to include in its semi-annual progress reports on the Project, detailed reporting on its ongoing consultation with First Nations, similar to the Revelstoke Unit 5 Project Quarterly Reports.

5. BC Hydro is directed to file a final report within six months of the end or substantial completion of the Project. The final report is to include a complete breakdown of the final costs of the Project, a comparison of these costs to the Expected Amount set out in the Application and provide an explanation of all material cost variances.

DATED at the City of Vancouver, in the Province of British Columbia, this 30th day of March 2012.

BY ORDER

Original signed by:

M.R. Harle
Panel Chair/Commission

British Columbia Transmission
CORPORATION™

Marcel Reghelini
Director, Regulatory Affairs
Phone: 604 699-7331
Fax: 604 699-7537
E-mail: marcel.reghelini@bctc.com

October 5, 2006

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Box 250
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

Re: British Columbia Transmission Corporation (BCTC)
Application for Certificate of Public Convenience and Necessity (CPCN)
For Vancouver Island Transmission Reinforcement Project (VITR)
Project Number 3698395

The British Columbia Utilities Commission (Commission) issued its Decision on the above referenced Application on July 7, 2006. At pages 206-207 of its Decision the Commission said:

> **The Commission Panel therefore orders BCTC to provide for approval by the Commission, within 30 days of a signed cable tender and no later than 90 days from this Decision, final P10 and P90 nominal dollar estimates for VITR that reflect the route option approved in this Decision and the signed cable tender. The estimates should be provided in a format similar to the P50 and P90 summary provided in response to Sea Breeze 2.45.1 in Exhibit B1-44. The estimate should show all adjustments made to reflect the final cable contract and there should no longer be any contingency included on the cable contract. In addition to the adjustments reflecting the final submarine cable contract, BCTC should clearly identify in its filing, with explanation, any other variances it makes to the P10 and P90 estimates for Option 1 through South Delta relative to the costs filed as part of this proceeding (Exhibit B1-1).**

At page 135 of its Decision the Commission also stated concerning the cost of the submarine cable contract:

> **"Further, the Commission Panel would expect BCTC to provide an estimate and justification for any ongoing contingency required for the submarine cable portions of VITR, following execution of the cable contract."**

EXHIBIT H-9

Through this correspondence BCTC provides, as directed, revised P10, P50 and P90 nominal dollar estimates for VITR that reflect the route option approved by the Commission and the signed cable contract.

In accordance with the above referenced direction, the revised cost estimates in millions of dollars are:

P10	$241.5
P50	$248.8
P90	$259.0

These revised estimates are based on:

a) the project cost estimate reported in Exhibit B1-67;
b) revised project definition costs as described below;
c) revised overhead and Interest During Construction (IDC) costs as described below;
d) minus the cost of underground construction through Tsawwassen (Option 2) reported in Exhibit B1-67 of $14.1 million;
e) plus the cost of overhead construction through Tsawwassen (Option 1) as reported in Exhibit B1-67 of $3.1 million;
f) reflection of the signed submarine cable contract value of $132 million; and
g) adjustments to the project contingency through a monte carlo analysis as described in:
    i. Exhibit B1-47 (BCTC's response to BCUC IR 3.175.2);
    ii. Exhibit B1-44 (BCTC's response to BCUC IR 3.193.2);
    iii. Exhibit B1-44 (BCTC's response to Sea Breeze IR 2.45.1);
    iv. Exhibits B1-79 and B1-85; and
    v. Transcript Volume 15 p. 2560, l. 25 – p. 2561, l. 9 and p. 2881, l. 7 – p. 2883, l. 7, and transcript volume 19, pp. 3434-3443 adjusted to reflect (a thru f) above, including the effect of reduced uncertainty resulting from the signed submarine cable contract.

The adjustments referenced above are summarized in the following table.

		P10 Estimate	P50 Estimate	P90 Estimate
1	Exhibit B1-67 Option 2 Project Cost Estimate	$222,647,000	$244,984,000	$279,472,000
2	Definition Cost Revision	$3,520,000	$3,520,000	$3,520,000
3	Remove Underground costs through Tsawwassen	($14,086,00)	($14,086,00)	($14,086,00)
4	Add Overhead costs through Tsawwasssen	$3,139,000	$3,139,000	$3,139,000
5	Reflect Signed Cable Contract	$20,878,000	$20,878,000	$20,878,000
6	Revised Contingency	$4,380,000	($10,000,000)	($32,500,000)
7	Revised Overhead Estimate	$636,000	$267,000	($359,000)
8	Revised IDC Estimate	$342,000	$115,000	($1,074,000)
9	Subtotal Net Change	$18,809,000	$3,833,000	($20,482,000)
10	Revised Project Estimate	$241,456,000	$248,817,000	$258,990,000

The attached Schedule 1 provides the revised cost estimates in a similar form as Exhibit B1-44, response to Sea Breeze IR 2.45.1 with additional detail where necessary.

Definition Phase Costs

The attached Schedule 2 is a revised definition phase cost forecast for the project reflecting the actual costs (excluding contingency, overhead and IDC) of the regulatory processes to date with an updated estimate for completion. The revised definition phase cost forecast is approximately $13.1 million of which $9.6 million are actual costs as of August 06, 2006.

The increase in the definition phase cost reflects the higher costs of dealing with the impact of the VIC application on BCTC's VITR proceeding and increased Environmental Assessment costs arising from the need to file an amendment to the Environment Assessment Certificate Application to reflect the Commission's decision approving Option 1 rather than the previously applied for Option 2 through Tsawwassen.

The revised definition phase costs and revised project costs contained in this report to the Commission do not include forecast costs for dealing with any

reconsideration applications before the Commission or for dealing with appeals before the courts. These processes are outside the control of BCTC and were not included in the cost estimates in Exhibit B1-67 or in the estimates determined by the Commission.

Submarine Cable Cost and Contingency

The Implementation Phase cost forecast has been updated for the Submarine Cable component to reflect the contract executed with Mitsubishi Canada Ltd. for design, manufacture, installation and testing of the 230 kV submarine cables, splices, terminations, pumping plants, related systems and spare parts. The Submarine Cable component cost is consistent with the preliminary figures filed by BCTC in correspondence dated April 27, 2006 and referenced by the Commission in the analysis provided in its Decision. All of the price escalation since BCTC's application forecast from July 2005 can be attributable to substantial increases in copper and other commodity prices since that time, partially offset by favorable foreign exchange movements.

The revised project estimates reported herein do not eliminate all contingency associated with submarine cables. The submarine cable costs identified at line 20 of Exhibit B1-67 included items not included in the cable tender, but associated with the submarine cable portion of the project, and items included in the cable contract but not fixed upon contract execution. These items include:

a) a unit price adjustment provided for in the cable contract for the final (and as yet unsurveyed) circuit length[1];
b) the terminal station work to be done by others based on the equipment proposed by Mitsubishi;
c) engineering costs for:
    a. project management
    b. construction management
    c. environmental monitoring
    d. contract administration
    e. design review and quality assurance;
d) environmental compensation and permit compliance; and
e) First Nations accommodation.

Considering the above listed items that remain unfixed following the execution of the cable contract, the contingency for the submarine cable portion of the P50 project cost reduces from $12.8 million included in Exhibit B1-67 and Exhibit B1-44, BCTC response to Sea Breeze IR 2.45.1 to $3.8 million. The P90 contingency for submarine cables reduces from $36.6 million to $6.3 million.

[1] At Transcript Volume 17, pp. 3057-3058 Mr. Nelson testified "I think in terms of the cable length, the final route is not determined until after the contract is awarded. It is then agreed between our engineering group and the cable supplier as to what that final route will be and what the final cable lengths will be. So in that respect, they have no risk. It is a matter of determining whether we're dealing in per cable 24,000 metres, 24,100 metres. Those finals lengths will be determined and the risk on the per unit length, on the cable length is not with the supplier, it is with BCTC."

Overhead and Interest During Construction (IDC)

The forecast in Exhibit B1-67 included Overhead and IDC at rates consistent with BCTC's approved F2006 revenue requirement.

As part of the approved negotiated settlement agreement on BCTC's F2006 Revenue Requirement (Order G-60-05) BCTC agreed to conduct an overhead capitalization study and file it as part of its next Revenue Requirement application. This study was filed with BCTC's F2007 Revenue Requirement application dated May 25, 2006. The result of the overhead capitalization study is an increase in the capitalized overhead rates. Although the Commission has yet to approve BCTC's F2007 Revenue Requirement, BCTC has reflected the results of the study in the forecast overhead rates in the revised project forecast contained herein. Specifically, overhead on the project increases from $6.3 million to $6.5 million in the P50 estimate and to $6.8 million in the P90 estimate.

In addition, BCTC has reflected its most up to date interest rate forecast for calculating IDC. This revised rate applied to the current forecast project cash flow results in IDC on the the project changing from $12.0 million to $12.1 million in the P50 estimate and to $12.6 million in the P90 estimate.

Sincerely,

Original signed by:

Marcel Reghelini
Director, Regulatory Affairs

Attachment
cc: Registered Intervenors

SCHEDULE 1

British Columbia Transmission Corporation
Vancouver Island Transmission Reinforcement
Cost Update and Contingency Analysis

Oct 5, 2006

	CPCN Application - Tsawwassen Option 1				Updated Option 1 Cost Forecast			
	Direct Capital Cost	P10	P50	P90	Direct Capital Cost	P10	P50	P90
1 Phase 1 Direct Capital (1)	**$9,540,000**				**$13,060,000**			
2 Contingency		$ -	$ 500,000	$ 500,000		$ -	$ 100,000	$ 300,000
3 Direct Capital		$ 9,540,000	$ 9,540,000	$ 9,540,000		$ 13,060,000	$ 13,060,000	$ 13,060,000
4 Overhead		$ 265,000	$ 278,000	$ 278,000		$ 370,904	$ 373,744	$ 379,424
5 Subtotal		$ 9,805,000	$ 10,318,000	$ 10,318,000		$ 13,430,904	$ 13,533,744	$ 13,739,424
6 IDC		$ 506,000	$ 532,000	$ 532,000		$ 688,739	$ 694,013	$ 703,505
7 TOTAL DEFINITION PHASE		**$ 10,311,000**	**$ 10,850,000**	**$ 10,850,000**		**$ 14,119,643**	**$ 14,227,757**	**$ 14,442,929**
		Contingency P10	Contingency P50	Contingency P90		Contingency P10	Contingency P50	Contingency P90
Submarine Cables								
8 Submarine Cable Contract	$ 112,196,000	(2,100,000)	$ 11,482,000	32,960,000	$ 132,040,000	$ 1,400,000	$ 2,500,000	$ 4,200,000
9 Environmental Compensation	$ 600,000	(10,000)	$ 60,000	180,000	$ 600,000	$ 20,000	$ 50,000	$ 90,000
10 Engineering (PM, CM, EM)	$ 4,600,000	(90,000)	$ 470,000	1,340,000	$ 4,790,000	$ 170,000	$ 440,000	$ 700,000
11 FN Accommodation	$ 1,800,000	(30,000)	$ 180,000	530,000	$ 1,800,000	$ 60,000	$ 160,000	$ 270,000
12 Subtotal Submarine Cables	**$ 119,196,000**	**$ (2,230,000)**	**$ 12,192,000**	**$ 35,010,000**	**$ 139,230,000**	**$ 1,650,000**	**$ 3,150,000**	**$ 5,260,000**
Terminal Stations								
13 Engineering	$ 550,000	(10,000)	$ 60,000	160,000	$ 550,000	$ 20,000	$ 50,000	$ 80,000
14 Construction	$ 4,916,000	(80,000)	$ 460,000	1,230,000	$ 6,500,000	$ 90,000	$ 600,000	$ 960,000
15 Subtotal Terminal Stations	**$ 5,466,000**	**(90,000)**	**$ 520,000**	**1,390,000**	**$ 7,050,000**	**$ 250,000**	**$ 650,000**	**$ 1,040,000**
16 Subtotal Submarine Systems	**$ 124,662,000**	**$ (2,320,000)**	**$ 12,712,000**	**$ 36,400,000**	**$ 146,280,000**	**$ 1,900,000**	**$ 3,800,000**	**$ 6,300,000**
17 Overhead Line	$ 41,156,000	$ 120,000	$ 3,247,000	$ 8,600,000	$ 41,156,000	$ 150,000	$ 3,650,000	$ 8,600,000
18 ARN	$ 1,515,000	$ 10,000	$ 110,000	$ 200,000	$ 1,515,000	$ 10,000	$ 110,000	$ 200,000
19 VIT	$ 13,310,000	$ 36,000	$ 880,000	$ 2,100,000	$ 13,310,000	$ 36,000	$ 880,000	$ 2,100,000
20 TBY	$ 3,283,000	$ 62,000	$ 270,000	$ 500,000	$ 3,283,000	$ 62,000	$ 270,000	$ 500,000
21 SAT	$ 2,550,000	$ 23,000	$ 180,000	$ 400,000	$ 2,550,000	$ 23,000	$ 180,000	$ 400,000
22 Subtotal Stations	**$ 20,658,000**	**$ 131,000**	**$ 1,440,000**	**$ 3,200,000**	**$ 20,658,000**	**$ 131,000**	**$ 1,440,000**	**$ 3,200,000**
23 Subtotal Terrestrial Work	**$ 61,814,000**	**$ 251,000**	**$ 4,687,000**	**$ 11,800,000**	**$ 61,814,000**	**$ 281,000**	**$ 5,090,000**	**$ 11,800,000**
24 Phase 2 Direct Capital	**$ 186,476,000**	P10	P50	P90	**$ 208,094,000**	P10	P50	P90
25 Contingency		**$ (2,069,000)**	**$ 17,399,000**	**$ 48,200,000**		**$ 2,181,000**	**$ 8,890,000**	**$ 18,100,000**
26 Direct Capital		$ 186,476,000	$ 186,476,000	$ 186,476,000		$ 208,094,000	$ 208,094,000	$ 208,094,000
27 Overhead		$ 5,109,000	$ 5,647,000	$ 6,498,761		$ 5,971,810	$ 6,162,346	$ 6,423,910
28 IDC		$ 9,756,000	$ 10,812,000	$ 12,434,453		$ 11,089,178	$ 11,442,987	$ 11,928,691
29 TOTAL IMPLEMENTATION PHASE		**$ 199,272,000**	**$ 220,334,000**	**$ 253,609,214**		**$ 227,335,988**	**$ 234,589,333**	**$ 244,546,601**
30 TOTAL CAPITAL COST		**$ 209,583,000**	**$ 231,184,000**	**$ 264,459,214**		**$ 241,455,631**	**$ 248,817,090**	**$ 258,989,530**

(1) See Schedule 2 for a breakdown of Definition Phase direct costs

SCHEDULE 2

British Columbia Transmission Corporation
Vancouver Island Transmission Reinforcement
Definition Phase Direct Costs

October 5, 2006

		CPCN Application July/05 Estimate ($000)	Actual Costs Through August/06 ($000)	Forecast to Complete ($000)	Updated Definition Phase Forecast ($000)
	CPCN Application				
1	Intervenor Funding		0	900	900
2	Commission Costs		0	910	910
3	Expenses (Allwest Reporting)		230	0	230
4	BCTC Legal		1269	0	1269
5	Subtotal Regulatory	**$995**	**$1,499**	**$1,810**	**$3,309**
6	BCH Eng Support	868	1162	50	1212
7	BCTC (System Planning & Other)	612	581	0	581
8	Expert Witnesses	0	83	0	83
9	Sub-total CPCN Application	**$2,475**	**$3,325**	**$1,860**	**$5,185**
	Environmental Assessment Application				
10	FN Capacity Funding	676	132	400	532
11	BCEAO Costs	0	0	0	0
12	BCTC Legal	284	186	150	336
13	BCH Eng Support	413	431	50	481
14	BCTC Other (MP & SPA)	98	119	50	169
15	Consultants/Experts	1820	1563	510	2073
16	Accommodation/Mitigation costs (1)	0	0	0	0
17	Sub-total Environmental Assessment	**$3,291**	**$2,431**	**$1,160**	**$3,591**
	US Permits/Approvals				
18	FN Capacity Funding	0	0	0	0
19	Agency Costs	0	0	0	0
20	BCTC Legal	142	93	75	168
21	BCH Eng Support	106	168	30	198
22	BCTC Other (MP & SPA)	30	56	0	56
23	Consultants/Experts	520	601	225	826
24	Accommodation/Mitigation costs (1)	0	0	0	0
25	Sub-total US Approvals	**$798**	**$918**	**$330**	**$1,248**
26	**Preliminary Design Engineering**	**$2,976**	**$2,951**	**$85**	**$3,036**
27	**DEFINITION PHASE DIRECT COSTS (2)**	**$9,540**	**$9,625**	**$3,435**	**$13,060**

(1) FN Accommodation and Environmental Mitigation/Compensation Costs are part of the Implementation Phase
(2) See Schedule 1 for Contingency, IDC & OH on P10, P50 & P90 estimates
(3) Expert witness costs for L. Erdreich and L Dybvig are included in line 4 (BCTC Legal) and not on line 8.

23.5 per cent more than previously forecast. The variance arises because this is an ongoing program that will likely continue through the life of the facility, and the previous forecast did not include costs for F2013 and F2014.

Note G9 - The Total Project Cost for the Burrard Asbestos Management Program, which is in implementation phase, is now forecast to be $19.6 million, $3.7 million or 22.6 per cent more than previously forecast. The variance arises because this is an ongoing program that will likely continue through the life of the facility, and the previous forecast did not include costs for F2013 and F2014.

Transmission and Distribution

Note T1 - The costs for the Central Vancouver Island project, which is in service, are now forecast to be $25.1 million or 27 per cent less than previously reported. This is primarily due to lower equipment costs and lower bids received from construction contractors. Market conditions and a procurement strategy for the project that consolidated smaller contracts into two large value general construction contracts contributed to lower costs.

Update - The latest forecast is now $31.3 million or 34 per cent less than previously reported for the same reasons noted above. $91,600,000 − $31,300,000 = $60,300,000

Note T2 - The costs for the Saanich Peninsula Project are $3.6 million or 12 per cent less than previously reported. Market conditions contributed to lower equipment costs of approximately $1 million. Construction costs are lower than estimated by approximately $2 million due to differences between the preliminary and final designs to achieve the scope of the project and the use of BC Hydro Field Operations crews reducing the need for construction management. The final design established that piles were not required to be installed to support the foundations in the substation, and that the spill containment structures for the two new substation transformers could be replaced to one common structure.

EXHIBIT H-10

Project Name: Columbia Valley Transmission Project (CVT)	
Forecast Capital Cost: $132 million - $209 million	**In-Service Date:** October 2012
Development Phase: Implementation	**Filing Reference:** C-5-10

Description:
The Columbia Valley Transmission (**CVT**) Project involves a new 124 km, 230 kV transmission line between the existing Invermere (**INV**) and Golden (**GDN**) substations; a new 3 km, 69 kV line through Golden; a new Kicking Horse substation (**KHS**) and related substation improvements. The target in-service date is October 2012. The total capital cost of the project is estimated to be $132 million - $209 million

Key Drivers:
- Load Growth

Issues Being Addressed:
Rapid load growth, particularly in the Golden area, has created a transmission capacity deficiency in the upper Columbia Valley region. There are transmission capacity constraints on circuit 60L271, a 230/69kV transformation constraint at the Invermere Substation and a 69/25/12kV transformation constraint at the Golden Substation.

BC Hydro's load forecasts indicate the capacity deficiency will continue to grow. The most recent forecast indicates that the existing 69 kV transmission line may not be able to meet the load in the Golden area as early as this coming winter (2010/11). Contingency plans are in place that can bridge the gap for the next two winter peak load periods through Demand Side Management (**DSM**) activities. Peak loads normally occur during very cold weather conditions. For short periods of time, the facilities can be operated above nameplate ratings particularly at lower ambient temperatures. If excessive loads persist, the Louisiana Pacific mill in Golden can either run its local generation or curtail production to limit any overloads until weather conditions improve.

Discussion of alternatives:
Non-Wire Alternatives
i) Demand Side Management.
ii) Local Generation.

Transmission Alternatives
i) Construct a new 138 kV transmission line from Invermere to Golden, approximately 120 km in length; Net Present Value (**NPV**): $114.6 million.
ii) Construct a 138 kV transmission line from Mica to Golden, approximately 220 km in length; NPV: $186.1 million.
iii) Construct a new 230 kV transmission line from Invermere to Golden, approximately 120 km in length; NPV: $115.6 million. This is the recommended alternative.

Additional Information:
The CPCN for the CVT Project was granted on September 3, 2010 under BCUC Order No. C-5-10.

EXHIBIT H-11

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BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER C-4-08

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Transmission Corporation
for a Certificate of Public Convenience and Necessity for the
Interior to Lower Mainland Transmission Project

BEFORE: R.H. Hobbs, Panel Chair and Commissioner
N.F. Nicholls, Commissioner
A.J. Pullman, Commissioner

August 5, 2008

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. On November 5, 2007, the British Columbia Transmission Corporation ("BCTC") applied (the "Application") pursuant to sections 45 and 46 of the Utilities Commission Act (the "Act") for a Certificate of Public Convenience and Necessity ("CPCN") for the Interior to Lower Mainland ("ILM") Transmission Project (the "ILM Project"); and

B. The purpose of the ILM Project is to reinforce the electric transmission system to increase the transmission capability of the ILM grid, and consists of a proposed new 500 kV alternating current transmission line, designated 5L83, between Nicola substation near Merritt and Meridian substation in Coquitlam, a new 500 kV series capacitor station which would be located approximately at the midpoint of the new 500 kV circuit, circuit terminations at each of Nicola and Meridian substations, and necessary telecommunications, protection and control equipment.; and

C. The new transmission line would parallel the existing 5L82 transmission line for most of the new circuit's approximately 246 km length and would be primarily on existing Right of Way, however, the specific alignment will be determined after the Environmental Assessment Certificate Application process and further public and First Nations consultation; and

* [D. The ILM Project has an estimated cost of $602 million, excluding First Nations accommodation costs, environmental mitigation and compensation costs, and costs for legal challenges, with an accuracy level of +30 percent to -10 percent, which is also the P50 estimated cost, and a target in-service date of fall 2014; and] *

EXHIBIT H-12

E. By Order G-137-07 dated November 7, 2007 the Commission determined an Oral Public Hearing was required for regulatory review of the Application, and scheduled a Procedural Conference for December 20, 2007 to address certain procedural issues; and

F. By Order G-172-07 dated December 21, 2007 the Commission established an amended regulatory timetable that included three community input sessions, a second Procedural Conference for March 25, 2008 and an Oral Public Hearing to commence April 14, 2008; and

G. By letter dated February 21, 2008 the Commission determined that it need not consider the adequacy of consultation and accommodation efforts on the ILM Project as part of its determinations in deciding whether to grant a CPCN for the ILM Project, which letter was followed by Reasons for Decision contained in Letter L-6-08 dated March 5, 2008; and

H. By letters dated March 4, 2008 and March 12, 2008 the Commission cancelled the community inputs sessions at Harrison Hot Springs, Coquitlam, and Merritt because of the low number of scheduled presentations and provided for those parties interested in making presentations the opportunity to do so at the Oral Public Hearing; and

I. By letter dated March 13, 2008 the Commission denied the request of the Kwikwetlem First Nation for the Commission to exercise its discretion, pursuant to section 102(2) of the Act, to suspend the hearing; and

J. By Order G-61-08 dated March 28, 2008 the Commission determined that the ILM proceeding could be completed as a written process, and issued an amended regulatory timetable without an Oral Public Hearing component; and

K. BC Hydro, the Independent Power Producers Association of British Columbia, the British Columbia Old Age Pensioners' Organization et al. ("BCOAPO"), the Joint Industry Electricity Steering Committee, the City of Abbotsford, Messrs. Harris and Casselman, and the Nlaka'pamx filed Final Submissions; and

L. By letter dated May 21, 2008 the Commission denied the application of BCOAPO for an adjournment of the proceeding pending the outcome of certain B.C. Court of Appeal decisions; and

M. BCTC filed its Reply Submission on June 3, 2008; and

N By letter dated June 17, 2008 the Commission cancelled the Oral Phase of Argument, and determined that the proceeding was concluded subject to the disposition of a leave application from Messrs. Harris and Casselman; and

O. By Letter L-30-08 dated June 23, 2008 the Commission denied the application for leave from Messrs. Harris and Casselman; and

P. The Commission has considered the ILM Project Application and the evidence and submissions presented on the Application and has determined that it is in the public interest that a CPCN be issued to BCTC for the ILM Project subject to the conditions and directions set out in the Order and Decision.

NOW THEREFORE pursuant to sections 45 and 46 of the Act the Commission orders as follows:

1. A Certificate of Public Convenience and Necessity is granted to BCTC for the ILM Project as described in the Application, subject to the following conditions:

   1.1 BCTC is to file the Update Report in accordance with the Decision issued concurrently with this Order, and

   1.2 the P50 cost estimate ($2014) that is to be filed with the Update Report is equal to or less than $725 million ($2014). The P50 cost estimate is to be calculated on a basis consistent with the calculation of the P50 cost estimate in the Application, and is to include First Nations accommodation costs, costs arising from the EAC requirements, and legal costs arising from CPCN or EAC appeals.

2. BCTC is directed to file with the Commission Quarterly Progress Reports on the ILM Project showing planned vs. actual schedule, planned vs. actual costs, and any variances or difficulties that the ILM Project may be encountering. The Quarterly Progress Reports will be filed within 30 days of the end of each reporting period.

3. BCTC is directed to file with the Commission a Final Report within six months of the end or substantial completion of the ILM Project that provides a complete breakdown of the final costs of the ILM Project, compares these costs to the P50 cost estimate that is to be filed with the Update Report and provides a detailed explanation and justification of all material cost variances.

5. BCTC is directed to comply with the directions of the Commission set out in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 5th day of August 2008.

BY ORDER

Original signed by:

Robert H. Hobbs
Panel Chair and Commissioner

Update - The latest forecast is now $22.2 million or 53 per cent less than previously reported due to lower tendered construction contracts and equipment cost, and efficiencies that will be achieved by reusing design work done for the Kidd1 project.

Note T8 - The Radium Substation 12/25 kV Conversion project, which is in implementation, is forecast to complete $2.2 million or 48 per cent more than previously reported. A number of changes to the scope to incorporate work to sustain the substation were added during the definition phase of the project. The addition contributed $1.5 million of the increase but the integration resulted in overall cost efficiency for the capital portfolio. The changes included replacing existing wood poles, determined to be at end of life during a site visit, with steel structures, replacing a disconnect switch, and adding a control building with a blast wall for separation from the transformer to reduce reliability and safety risk. A contract change after the completion of the initial project plan and estimates increased the costs by $0.4 million. A multi-staged construction schedule was used in order to ensure safe working conditions, which caused an extended need for a mobile substation and increased staff hours at the Fraser Valley office, resulting in a further $0.4 million increase.

Update - The latest forecast is now $2.6 million or 56 per cent more than previously reported for the same reasons noted above.

Note T9 - The costs for the 500/230kV Selkirk Transformer T4 Addition Project, which is now in service, are forecast to be $3.9 million or 17 per cent higher than previously reported. The failure of an existing transformer (T1) at the station resulted in a one year delay to the T4 project when one of the three phase transformers ordered for installation in the T4 position was used to replace the failed T1 phase and a replacement transformer phase needed to be procured. The project cost increase is mainly from higher cumulated interest charges, escalation and additional construction costs from multiple mobilization-demobilization.

Note T10 - The costs for the Interior to Lower Mainland Project (ILM), are forecast to be $150 million or 25 per cent higher than previously forecast, mainly due to First Nations'

$602,000,000 + 150,000,000 = 752,000,000

accommodation costs, costs arising from the EAC requirements, and legal costs arising from the CPCN and Environmental Assessment Certificate (EAC) appeals, and also updated tender costs for the transmission line, including contingencies.

Note T11 - The costs for the East Toba and Montrose Creek Hydroelectric Project, which is in service, are forecast to be $5.4 million or 14 per cent less than previously reported. The main causes for the variance include savings from 1L48 being originally built to 230 kV and not requiring anticipated upgrade from 138 kV, and construction costs coming in below estimate due to market timing. The variances were partially offset by higher than anticipated environmental and engineering costs.

Note T12 - The costs for the Dokie Wind Farm IPP Project, which is now in service, are forecast to be $4.1 million or 22 per cent more than previously reported. The increase in expenditures are primarily related to the demobilization and remobilization costs associated with putting the project on hold in March 2009, (due to delays in the IPP project schedule) and subsequently restarting construction in October 2009, including additional interest during construction costs. Soil settlement issues were noticed when the project restarted, which also required remediation and added to the construction cost.

Note T13 - The Athalmer Substation Transformer Replacement Project, currently in the implementation phase, is forecast to complete at $2.2 million or 22 per cent less than previously reported. The decrease in expenditures is primarily related to lower construction bids due to favourable market conditions and unused contingencies for site risks that did not materialize.

Note T14 - The Vanderhoof Substation T1 Transformer Replacement Project, currently in the implementation phase, is forecast to complete at $5.4 million or 79 per cent more than previously reported. A number of additions to the scope were made during the definition phase of the project. The scope additions include the need to replace the existing wood-pole feeder section, which is in poor condition and unsafe to operate and

Project Name: Interior to Lower Mainland Project (ILM)

Forecast Capital Cost: $540 million – $780 million	**In-Service Date:** October 2014
Development Phase: Definition	**Filing Reference:** G-83-09; G-38-09; G-2-10; G-15-11; C-4-08

Description:
The project will install a new series compensated 255 km, 500 kV transmission line (5L83) between Nicola substation (near Merritt) and Meridian substation (in Coquitlam) with a series capacitor station at Ruby Creek.

Key Drivers:
- Load Growth

Issues Being Addressed:
The existing ILM transmission system will not have adequate thermal capability for reliable transfer of Interior generation resources to serve customer loads in the Lower Mainland and Vancouver Island during peak periods, or to continue to take the same advantage of available trade opportunities in off-peak periods, sometime before 2014.

Discussion of alternatives:
The alternatives for the project were discussed in BCTC's Application for a Certificate of Public Convenience and Necessity for the ILM Transmission Project.

Additional Information:

The CPCN issued by the BCUC on August 5, 2008 is effectively suspended pending the outcome of a reconsideration proceeding. Several First Nations appealed the BCUC's decision to exclude consideration of the adequacy of consultation from the scope of its review of the CPCN application. The B.C. Court of Appeal ruled that the BCUC ought to have considered the adequacy of consultation up to the point of the BCUC Decision. The BCUC subsequently initiated a proceeding for the purpose "of determining whether the Crown's duty to consult and accommodate the Appellants had been met up to that decision point" as directed by the Court.

On February 3, 2011, the BCUC released its decision on the Reconsideration of the CPCN issued on August 5, 2008. The overall question before the BCUC was whether the consultation efforts were adequate up to the point of the BCUC's CPCN decision. In considering the scope of its assessment, the BCUC found that the duty to consult first arose in December 2005 when the BCTC's Board of Directors first approved funding for the Definition Phase of the ILM project. The BCUC assessed consultation up to August 5, 2008, when the CPCN was issued.

Of the nine issues raised by First Nation Interveners and considered by the BCUC as part of its assessment of the adequacy of the overall consultation process, the BCUC found consultation to be fully adequate with all First Nations on seven of the issues. However, the BCUC found consultation to have some deficiencies with some First Nations on two issues:

1. Consultation on alternatives to 5L83, including an HVDC alternative; and
2. An explanation of why revenue sharing was not available.

BC Hydro has been given 120 days to address these deficiencies with the applicable First Nations and to submit a report to the BCUC setting out the steps taken to rectify the deficiencies.

In the fall of 2009, a group of First Nations (NNTC, and UNIB/ONA) petitioned the B.C. Supreme Court for a judicial review of the Province's decision on the Environmental Assessment Certificate (made in June 2009). The Court initiated a hearing on February 7, 2011 and a decision is expected in the summer 2011.

Should ILM not be in service by fall 2014, under Ministerial Order No. M-314 dated November 5, 2010, BC Hydro can rely on Burrard Thermal for a maximum capacity of 900 MW until all of the Mica 5/6, 5L83, and Meridian transformer projects are in service. BC Hydro could also import additional electricity from the U.S. if required.

Amended F12-F14 RRA:
Forecast Capital Cost: $709 million (+10 per cent / - 10 per cent)
Change to In-Service Date: from October 2014 to January 2015 (F2015)
Capital Addition Impact in test period: none
This project is now in the implementation stage.

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BRITISH COLUMBIA UTILITIES COMMISSION

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ORDER NUMBER C-3-10

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Transmission Corporation
for a Certificate of Public Convenience and Necessity
for the Vancouver City Central Transmission Project

BEFORE: A.A. Rhodes, Commissioner/Panel Chair
L.A. O'Hara, Commissioner
A.J. Pullman, Commissioner

June 2, 2010

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. On September 21, 2009, the British Columbia Transmission Corporation (BCTC) applied (the Application), pursuant to sections 45 and 46 of the *Utilities Commission Act* (the Act), to the British Columbia Utilities Commission (Commission) for a Certificate of Public Convenience and Necessity (CPCN) to construct and operate the Vancouver City Central Transmission Project (the VCCT Project) as described in this Application; and

B. BCTC is proposing the VCCT Project as the preferred solution to: i) serve load growth in the Mount Pleasant/South False Creek area, ii) resolve reliability concerns associated with the end of life condition of the Main Street distribution duct banks being used to serve the Mount Pleasant/South False Creek area, and iii) resolve reliability concerns in view of the zero-rating of transmission circuit 2L53; and

total $201M

C. The VCCT Project as originally filed, had an estimated capital cost of approximately $174 million and a further $27 million to be incurred for British Columbia Hydro and Power Authority's Substation Distribution Assets (SDA), which were not at that time the subject of the Application, and included the construction of a new Mount Pleasant substation and a new transmission line approximately 8 km in length that follows the route described in the Application as Route Option B; and

D. In the F2010/2011 BCTC Capital Plan Decision, dated July 13, 2009, the Commission directed BCTC to work with British Columbia Hydro and Power Authority (BC Hydro) to either accept its proposal to have BCTC or BC Hydro seek regulatory approval for the entire project, including both transmission and SDA components, or develop an alternative approach and directed BCTC and BC Hydro to provide their report within 90 days from the date of Decision; and

EXHIBIT H-13

E. On October 21, 2009, BCTC filed amendments to its Application to incorporate an application for an order issuing a CPCN to BC Hydro for the construction and operation of the VCCT Substation Distribution Assets; and

F. On Wednesday, November 25, 2009, the Commission held a Procedural Conference to hear submissions on the appropriate regulatory process for the review of the Application; and

G. By Order G-159-09 dated December 16, 2009, the Commission directed that the Application be reviewed by way of a Written public hearing process; and

H. The Written public hearing process concluded with the filing of BCTC's Reply submission on April 15, 2010; and

I. The Commission Panel has reviewed the evidence and submissions of all of the parties and determines that the Project is in the public interest.

NOW THEREFORE pursuant to section 45 of the Act, the Commission orders as follows:

1. A CPCN is granted to BCTC for the VCCT Project and a further CPCN is granted to BC Hydro for the construction of the VCCT Substation Distribution Assets, as applied-for.

2. BCTC and BC Hydro are to comply with the directives in the Commission's Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this *Second* day of June 2010.

BY ORDER

Original signed by:

A. A. Rhodes
Commissioner/Panel Chair

3.1.2.1 Tunnel

The portion of Circuit 2L20 which travels beneath False Creek (approximately 850 meters) will require the construction of a tunnel. BCTC describes two methods of tunnel construction which could be appropriate for the geological conditions: Horizontal Directional Drilling (HDD) and tunneling using a Tunnel Boring Machine (TBM). (Exhibit B-1, p. 69; Appendix D – Golder Geotechnical Overview Assessment Report, p. 18)

HDD involves the use of a steerable, fluid-jet assisted, mechanical cutting tool to bore a small pilot hole from the ground surface, generally along a curved arc. Reamers are then pulled through the pilot hole to enlarge it to a diameter sufficient to pull the conduit bundle through. The hole is stabilized by circulating a large volume of viscous fluid such as bentonite slurry, which also removes the drill cuttings. The tunnel would be about 15 to 30 meters below the bed of False Creek. Installation time would be in the order of four to five months. This method is generally cheaper than tunnelling where conditions are favourable. (Exhibit B-1, pp. 69-71; Appendix D – Golder Geotechnical Overview Assessment Report, p. 14)

The TBM method requires the excavation of vertical entry and exit shafts, the walls of which are supported by temporary shoring. Large work areas are required at shaft locations. The tunnel would be about 12-18 meters beneath the bed of False Creek. Construction time is estimated to take a minimum of eight months. (Exhibit B-1, pp. 69-71; Appendix D – Golder Geotechnical Overview Assessment Report, p. 12)

BCTC notes that the use of HDD, if feasible, would result in a lower cost for the False Creek crossing and is investigating the subsurface conditions with a view to determining feasibility. The cost estimates provided assume the more expensive Tunnel Boring Machine methodology. Therefore, if HDD can actually be used, the project cost will be lower. (Exhibit B-1, p. 71) Without the additional information provided by an exploratory HDD program, Golder opines that the chance of successful completion of an 813 mm diameter HDD bore is about 60 percent, as compared to the chance of successful completion of a 3 m diameter tunnel using an Earth Pressure Balanced (EPB) Tunnel

Boring Machine of 100 percent. Golder notes that if HDD can be used, cost savings in the order of $8 to 16.5 million may be achieved. (Exhibit B-1, Appendix D, p. 17)

$12.25M in midpoint $20.1M − $12.25M =

3.1.2.2 Project Costs

* Based on a -15%/+30% accuracy level, BCTC estimates the Project will cost a total of $200.9 million, which includes $173.7 million for transmission assets and $27.2 million for system distribution assets. (Exhibit B-1, p. 73 Revised)

The following table shows a breakdown of the Project Costs:

Table 2 Vancouver City Central Transmission Project Cost Schedule

	Project Cost ($ thousands)	Transmission	SDA	Total
	BCTC Managed Cost			
1	Project Management	915	143	1,058
2	Consultation and Regulatory	2,460	385	2,845
3	Definition Engineering/Environmental	3,546	556	4,102
4	Properties Acquisition and ROW	2,971	466	3,437
5	Subtotal	9,892	1,550	11,442
	Transmission			
6	Cables	25,767	-	25,767
7	Civil - Duct Banks	20,294	-	20,294
8	Civil - Manholes	1,996	-	1,996
9	Tunnel	16,073	-	16,073
10	Subtotal	64,130	-	64,130
	Mount Pleasant Substation			
11	Building and Land	28,393	-	28,393
12	12kV Switchgear	-	10,886	10,886
13	230kV GIS	10,356	-	10,356
14	230kV Transformer	-	8,311	8,311
15	Protection & Control	3,889	-	3,889
16	Station Service / Grounding	2,238	-	2,238
17	Telecom	1,474	-	1,474
18	System Operations	57	-	57
19	Subtotal	46,407	19,197	65,604
	Sperling Substation			
20	230kV GIS	3,167	-	3,167
21	Protection & Control	415	-	415
22	Station Service / Grounding	213	-	213
23	Telecom	305	-	305
24	System Operations	20	-	20
25	Subtotal	4,120	-	4,120
	Cathedral Square Substation			
26	230kV GIS	4,953	-	4,953
27	Protection & Control	759	-	759
28	Station Service / Grounding	209	-	209
29	Telecom	100	-	100
30	System Operations	27	-	27
31	Subtotal	6,048	-	6,048
32	**Inflation**	8,663	1,712	10,375
33	**Contingency**	18,650	3,239	21,889
34	**Overhead**	4,427	688	5,115
35	**Interest During Construction**	11,375	838	12,213
36	**Gross Total**	**173,711**	**27,225**	**200,936**
37	Percentage of total project	86.5%	13.5%	100.0%

Source: Table 5-3, Exhibit B-1, p. 74

BRITISH COLUMBIA
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NEWS RELEASE

For Immediate Release
2010EMPR0023-000642
May 28, 2010

Ministry of Energy, Mines and Petroleum Resources

NTL AGREEMENTS WILL CREATE JOBS, POWER B.C.'S NORTHWEST

VICTORIA – Clean energy agreements between BC Hydro, British Columbia Transmission Corporation (BCTC), Coast Mountain Hydro L.P., a wholly owned subsidiary of AltaGas Income Trust Ltd. (AltaGas) and the Tahltan Nation will help to create jobs, provide clean and renewable electricity to B.C.'s Northwest, and power the development of the Northwest Transmission Line (NTL), announced Blair Lekstrom, Minister of Energy, Mines and Petroleum Resources.

"I congratulate all the partners for working to make these agreements a reality," said Lekstrom. "These agreements will open up the Northwest by providing access to some of the up to 2,000 megawatts of clean energy potential that has been identified in the region and will reduce greenhouse gas emissions. They are part of our long-term vision for clean, renewable, low-cost energy for all British Columbians."

The agreements, which will support construction of the NTL, include:

- A $180-million umbrella agreement between AltaGas and BCTC for the construction and development of the NTL.
- An electricity-purchase agreement between BC Hydro and AltaGas for the Forrest Kerr clean energy project near Bob Quinn Lake.
- An impact-benefit agreement between AltaGas and the Tahltan Nation for the Forrest Kerr project.

The NTL project also includes $130 million in funding through the Government of Canada's Green Infrastructure Fund, announced by Prime Minister Stephen Harper last September. The estimated ratepayer contribution to the NTL will be $94 million, which is expected to be offset by contributions from future clean, renewable energy projects and/or mine developments.

"The Forrest Kerr project represents an important evolution in AltaGas' power business as we continue to build long-term, contracted, generation assets," said David Cornhill, chairman and chief executive officer of AltaGas. "This project will provide the people of British Columbia with clean and reliable power from a significant water resource. For our investors, this announcement comes at an important time in history as governments move to reduce emissions while building for the future."

-more-

EXHIBIT H-14

The NTL is a $404-million, 287-kilovolt, 335-kilometre, publicly owned transmission line from Skeena Substation (near Terrace) to Bob Quinn Lake. It will provide a secure interconnection point for clean generation projects, supply clean electricity to support industrial developments in the area, and reduce greenhouse gas emission by enabling communities now relying on diesel generation to connect to the grid.

An application for an environmental assessment certificate for the NTL was accepted by the B.C. Environmental Assessment Office on April 14, 2010. The 180-day application review period is underway, and public meetings have been held in the project area.

"BC Hydro welcomes the opportunity to extend the provincial grid to ensure industries that generate jobs for British Columbians are fuelled by clean energy and to improve the quality of life in rural and remote communities that are now dependent on diesel generators," said Dave Cobb, BC Hydro president and CEO. "In addition, the transmission line will enable us to purchase clean energy from the Forrest Kerr project and, in the future, from other renewable power projects, helping us to become electricity self-sufficient by 2016."

Construction of the NTL is scheduled to begin in late 2010 and will create an estimated 280 construction jobs, subject to receiving necessary environmental assessment and regulatory approvals and accommodation of First Nations' interests. The NTL is the first step in reinvigorating the regional economy of B.C.'s Northwest. It will provide significant direct economic stimulus to the region. It will also leverage an investment of more than $700 million from AltaGas's clean energy project that will lead to the creation of 400 jobs. The investment and number of jobs is expected to rise with new industrial development.

British Columbia's new Clean Energy Act, which is currently before the B.C. legislature, sets the foundation for a new future of electricity self-sufficiency, job creation and reduced greenhouse gas emissions, powered by unprecedented investments in clean, renewable energy across the province.

-30-

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BC Hydro signs construction contract for Northwest Transmission Line

September 7, 2011 · Updated 4:56 PM
0 Comments

BC Hydro has now signed the largest contract connected to its Northwest Transmission Line.

It calls for a design and build of the line which will stretch 344km from the crown corporation's Skeena Substation south of Terrace to Bob Quinn on Hwy37 North.

The contract with Valard, a Quanta company, and Burns and McDonnell was not unexpected as the two companies topped a BC Hydro shortlist last year and had already established operations in the northwest by doing prep work.

The contract was signed August 31, clearing the way for full-on construction with an anticipated finishing date of December 2013.

"There's been a lot of work already going on," said BC Hydro VP Bruce Barrett of environmental assessments, forestry work, preliminary design and more lately, geotechnical work along the line's route.

BC Hydro did not have Valard and Burns and McDonnell commit specifically to using northwest companies or residents for supplies, service and labour but Barrett said the crown corporation is assured there will be regional benefits.

"There will be substantial opportunity for northwest businesses to participate," he added.

Barrett also noted that BC Hydro has already financed what it calls "boot camps" for mainly aboriginal youth which provide the basics leading up to entering apprenticeship programs.

But Barrett would not release the dollar value of the Valard and Burns and McDonnell contract.

"It's BC Hydro's policy not to disclose," he said, citing confidentiality reasons.

It's also BC Hydro policy not to disclose the dollar value of the impact benefits agreements it signs with First Nations over whose traditional territory the line will travel.

So far the crown corporation has signed agreements with the Nisga'a Nation and a number of other First Nations, including the Kitselas east of Terrace.

Barrett was also not sure if BC Hydro would release the sum total of the impact benefits agreements once it has signed all of the agreements it can with First Nations.

But Barrett did say BC Hydro prefers people stop using the figure of $404 million when talking about the capital cost of the project.

Although that figure is used in BC Hydro's application for an environmental certificate and is widely quoted in provincial government press releases, Barrett says the corporation uses a range of anywhere from $364 million to $525 million.

"We're still operating within that range," he said of the dollar values which BC Hydro first developed at least four years ago.

The $404 million figure does not include the dollar value of the impact benefits agreements it has been signing with the Nisga'a and with First Nations, Barrett added.

He said the BC Hydro was confident the line will be built within the suggested dollar value range.

To date, BC Hydro has spent nearly $30 million, Barrett said.

PLANNED PROJECTS OVER $50 MILLION

BC Hydro has planned for the following projects, each with capital costs expected to exceed $50 million, listed according to targeted completion date. Some of the projected cost ranges may be large, particularly for projects still in Definition Phase, as scope, final costs and completion dates are still to be determined. These projects have been approved by the Board of Directors.

COLUMBIA VALLEY TRANSMISSION PROJECT (CVT)	Oct 2012 In-Service	$112 Total cost ($ millions)[1]	$112 LTD cost[2] ($ millions)
Constructed a new 230 kV transmission line from the existing Invermere substation to a new substation (called Kicking Horse) built on the west side of the Columbia River near the town of Golden; constructed a new 69 kV transmission line between the new Kicking Horse substation and the existing Golden substation; expanded Golden and Invermere substations and modified the Cranbrook substation—all to meet load growth in the Columbia Valley area. CVT project is now in close out phase.			

STAVE FALLS SPILLWAY GATE REPLACEMENT	Mar 2013 In-Service	$46 Total cost ($ millions)[1]	$46 LTD cost[2] ($ millions)
Upgraded the spillway gates[3] at the Stave Falls dam to increase public and employee safety and ensure the gates meet flood discharge reliability requirements.			

SMART METERING & INFRASTRUCTURE PROGRAM	F2015 Targeted completion	$840-930[4] Total cost ($ millions)[1]	$583 LTD cost[2] ($ millions)
The Smart Metering and Infrastructure Program (SMI) includes the installation of 1.9 million smart meters in homes and businesses across the province, optional conservation tools, an advanced telecommunications infrastructure to support electricity system management and customer applications, and information technology to support customer billing, load forecasting and outage management systems. The SMI Program plays a key role in modernizing BC Hydro's electricity grid. All customers will benefit from more choice and control over their electricity usage and operational efficiencies.			

VANCOUVER CITY CENTRAL TRANSMISSION (VCCT)	F2014 Targeted completion	$160-201 Total cost ($ millions)[1]	$138 LTD cost[2] ($ millions)
Build an enclosed 230/12 kV substation in the Mt. Pleasant area of Vancouver and two new underground 230 kV transmission lines connecting the new substation to the existing transmission network to serve growing loads in the Mt. Pleasant/False Creek area and maintain a reliable supply of electricity to other areas of Vancouver.			

MICA SF_6 GAS INSULATED SWITCHGEAR (GIS) REPLACEMENT PROJECT	F2014 Targeted completion	$199 Total cost ($ millions)[1]	$140 LTD cost[2] ($ millions)
Replace the switchgear system at the Mica Generating Station to ensure the reliability of this key generating station and reduce SF_6 (a greenhouse gas) leakage. The switchgear system uses 500 kV circuits to conduct the energy from the Mica underground powerhouse to the surface, where it transitions to transmission lines.			

SEYMOUR ARM SERIES CAPACITOR STATION (SASC)	F2015 Targeted completion	$49-58 Total cost ($ millions)[1]	$13 LTD cost[2] ($ millions)
Construct a 500 kV series capacitor station adjacent to the existing transmission lines 5L71 and 5L72, which run between Mica Generating Station and the Nicola Substation near Merritt. The capacitor station will increase the transmission capacity of the lines and allow the Mica Generating Station to securely deliver its full station output with the new generating units 5 and 6 in place.			

DAWSON CREEK/ CHETWYND AREA TRANSMISSION (DCAT)	F2015 Targeted completion	$220-255 Total cost ($ millions)[1]	$24 LTD cost[2] ($ millions)
The project will expand the Peace Region 230kV transmission system to the Dawson Creek-Chetwynd Area to supply the high area load growth. The solution will include the construction of new 230kV lines between Dawson Creek (DAW) and Bear Mountain (BMT), and from BMT to a new station called Sundance (SLS), located approximately 19 km east of Chetwynd.			

NORTHWEST TRANSMISSION LINE PROJECT (NTL)	F2015 Targeted completion	$736-746 Total cost ($ millions)[1]	$340 LTD cost[2] ($ millions)
Construct an approximately 340 km, 287 kV transmission line between Skeena Substation near Terrace and a new substation to be built near Bob Quinn Lake to ensure a reliable supply of clean power to potential industrial developments in the area; provide a secure interconnection point for clean generation projects; and potentially help certain northwest communities access their power from the electricity grid rather than diesel generators. **Total cost range represents the gross cost of the project and has not been netted for contributions, which total $220 million from the Federal Government and a customer. The LTD cost has not been netted for $23.4 million in contributions received from the Federal Government.*			

[1] The capital expenditure amounts are presented to reflect the impact of IFRS and do not include dismantling or asset retirement costs.

[2] Life to date (LTD) costs to March 31, 2013.

[3] Spillway gates control the amount of water that can be discharged from the reservoir. They are generally used in times of flood to pass high inflows.

[4] Smart Metering & Infrastructure Program amount includes both capital costs and operating expenditures subject to regulatory deferral.

CAPITAL EXPENDITURES SUMMARY

INTERIOR TO LOWER MAINLAND PROJECT (ILM)	F2015 Targeted completion	$690-725 Total cost ($ millions)[1]	$251 LTD cost[2] ($ millions)
Construct a new 500 kV transmission line, approximately 255 km in length, between the Nicola Substation near Merritt and the Meridian Substation in Coquitlam and build a new series capacitor station at Ruby Creek near Agassiz to help meet domestic load growth in the Lower Mainland.			

MERRITT AREA TRANSMISSION PROJECT (MAT)	F2015 Targeted completion	$58-66 Total cost ($ millions)[1]	$5 LTD cost[2] ($ millions)
Construct a new 138 kV radial transmission line from the existing Highland Substation to a new substation in Merritt to meet the increased demand for power in the Merritt area.			

UPPER COLUMBIA CAPACITY ADDITIONS AT MICA—UNITS 5 & 6	F2015–F2016 Targeted completion	$627-714 Total cost ($ millions)[1]	$284 LTD cost[2] ($ millions)
Install two additional 500 MW generating units into existing turbine bays at the Mica Generating Station. The new units are similar to the four existing units, but with more efficient turbines. Includes construction of a series capacitor station located near the mid-point on the existing Mica-Nicola 500kV transmission lines.			

HUGH KEENLEYSIDE SPILLWAY GATE RELIABILITY UPGRADE	F2016 Targeted completion	$116-123 Total cost ($ millions)[1]	$45 LTD cost[2] ($ millions)
Upgrade the spillway gates[3] at the Hugh Keenleyside Dam to increase public and employee safety and ensure the gates meet flood discharge reliability requirements.			

G.M. SHRUM UNITS 1 TO 5 TURBINE REPLACEMENT	F2016 Targeted completion	$197-272 Total cost ($ millions)[1]	$70 LTD cost[2] ($ millions)
Replace the turbines for Units 1 to 5 to reduce the risk of runner failure, decrease maintenance costs and improve operating efficiency.			

ISKUT EXTENSION PROJECT	F2016 Targeted completion	$167-180 Total cost ($ millions)[1]	$0 LTD cost[2] ($ millions)
Construction of a 92 km, 287 kV transmission extension, plus a 16 km distribution line from Bob Quinn substation. The transmission line would terminate at a new substation at Tatooga Lake and the 16 km, 25 kV distribution line continuing to Iskut. **The total cost range represents the gross cost of the project and has not been netted to reflect contributions of $39.6 million from a customer.*			

SURREY AREA SUBSTATION PROJECT	F2016 Targeted completion	$76-94 Total cost ($ millions)	$1 LTD cost[2] ($ millions)
Construct a new 200 MVA 230/25 kV substation in the Fleetwood area of Surrey. The supply to the station will be from circuit 2L75 and will allow for increased station capacity of 400 MVA.			

RUSKIN DAM SAFETY AND POWERHOUSE UPGRADE	F2018 Targeted completion	$626-748 Total cost ($ millions)[1]	$145 LTD cost[2] ($ millions)
This project upgrade will meet modern safety and seismic requirements and replace the powerhouse equipment, which is in poor condition. It is expected to take six years to complete and includes: reinforcement of the right bank; seismic upgrade of the dam and water intakes; powerhouse upgrades; and, relocation of the switchyard. Once completed, the upgraded facility will be reliable and safe and will produce enough electricity to serve more than 33,000 homes.			

JOHN HART GENERATING STATION REPLACEMENT	F2019 Targeted completion	$1,004-1,149 Total cost ($ millions)	$81 LTD cost[2] ($ millions)
Replace the existing six-unit 126 MW generating station (in operation since 1947) and add integrated emergency bypass capability to ensure reliable long-term generation and to mitigate earthquake risk and environmental risk to fish and fish habitat. In February 2013, BC Hydro received a Certificate of Public Convenience and Necessity from the BCUC for the project.			

SITE C CLEAN ENERGY PROJECT	2023* Targeted completion	$7,900 Total cost ($ millions)[1]	$258 (deferred capital) LTD cost[2] ($ millions)
Site C is a proposed third dam and 1,100 megawatt hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It would be capable of producing approximately 5,100 gigawatt-hours of electricity annually and would deliver firm electricity with a high degree of flexibility. The Site C project is currently in Stage 3—environmental and regulatory review, which includes an independent federal and provincial environmental assessment. Subject to environmental certification, construction would take about seven years and Site C would provide clean, reliable power to B.C. for more than 100 years. **Planned in-service date for all units. This timeline reflects the project's current regulatory schedule and is subject to change based on a review of the construction schedule.*			

[1] The capital expenditure amounts are presented to reflect the impact of IFRS and do not include dismantling or asset retirement costs.

[2] Life to date (LTD) costs to March 31, 2013.

[3] Spillway gates control the amount of water that can be discharged from the reservoir. They are generally used in times of flood to pass high inflows.

Project Name: Northwest Transmission Line (NTL)

Forecast Capital Cost:	**In-Service Date:**
$364 million - $525 million	December 2013
Development Phase:	**Filing Reference:**
Definition	

Description:
The Northwest Transmission (**NTL**) Project consists of approximately 340 km of 287 kV transmission line from the Skeena Substation near Terrace to a new substation at Bob Quinn. The NTL will provide infrastructure for connecting new sources of generation, future industrial development and communities in the area.

Key Drivers:

- The primary driver to the NTL is to facilitate the connection of clean energy to grid. Other drivers include the support of industrial development in the region, the reduction of greenhouse gas emissions and the potential to get communities off diesel power. The project is aligned with the CEA.

Issues Being Addressed:
The line avoids multiple privately owned and operated lines in the area and promotes new development that might not otherwise be feasible through a combined lower cost participation approach.

Discussion of alternatives:
High level analysis was undertaken for various alternatives including:

i) Upgrade of the existing 138 kV line. This would not create capacity that would meet the kind of growth anticipated in the area.
ii) Build a 287 kV line from Kitwanga. This would require a new substation off the 500 kV line at Telkwa, would involve approximately 25 km of extra line and would be more expensive than the alternative chosen.
iii) Upgrade of the existing 138 kV line as far as Meziadin with a double circuit 138/287 kV line from the Skeena Substation. This reduces rights-of-way requirements, but creates logistical problems in terms of temporary service while the structures are being replaced and is more expensive than the alternative chosen.
iv) Upgrade of the existing 138 kV line as far as Meziadin with a double circuit 287 kV line from the Skeena Substation and new substations to serve the communities now serviced by the existing 138 kV line. This reduces rights-of-way requirements, but has the same logistical problems as iii) and is more expensive than the alternative chosen.
v) Replacement of the existing 138 kV line as far as Meziadin with a single circuit 287 kV line. More expensive than the existing proposal and requires the upgrade of the existing stations that serve the communities from the 138 kV line and also has the same logistical problems as iii) and iv), but requires less new rights-of-way.
vi) Build a 287 kV transmission line from the Skeena Substation near Terrace to a new substation at Bob Quinn. This alternative is the least expensive. (Selected alternative.)

Additional Information:
On May 28, 2010, agreements between BC Hydro, BC Transmission Corporation, Coast Mountain Hydro L.P., a wholly owned subsidiary of AltaGas Income Trust Ltd. (**AltaGas**), and the Tahltan Nation were announced by the Ministry of Energy, Mines and Petroleum Resources. These agreements, which will support construction of the NTL, include a $180-million umbrella agreement between AltaGas and BCTC for the construction and development of the NTL project.

The NTL project also includes $130 million in funding through the Government of Canada's Green Infrastructure Fund, announced by Prime Minister Stephen Harper in September 2009.

Amended F12-F14 RRA:
Forecast Capital Cost: $561 million (+10 per cent/-10 per cent)
Change to In-Service Date: December 2013 to May 2014
Capital Addition Impact in test period: $145 million decrease (net of CIA) [reflecting IFRS]
Reason for Capital Addition Change: Project in-service delay to F2015

The forecast cost for this project has increased compared to the range provided in the F12-F14

($741M-$180M= $561M.

RRA to incorporate the cost of Impact Benefits Agreements, which were previously excluded, additional costs for environmental compensation resulting from the Environmental Assessment (EA), and an update of the cost estimate.

The project is now in the implementation stage.

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER C-5-13

TELEPHONE: (604) 660-4700
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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Hydro and Power Authority
for a Certificate of Public Convenience and Necessity for the
Dawson Creek/Chetwynd Area Transmission Project

BEFORE: L.A. O'Hara, Panel Chair/Commissioner
C.A. Brown, Commissioner
D.M. Morton, Commissioner

April 25, 2013

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. On July 11, 2011, British Columbia Hydro and Power Authority (BC Hydro) applied (the Application) pursuant to subsection 46(1) of the *Utilities Commission Act* (the Act), to the British Columbia Utilities Commission (Commission) for a Certificate of Public Convenience and Necessity (CPCN) to construct and operate the Dawson Creek/Chetwynd Area Transmission Project (the Project) as described in the Application;

B. The Project is located in the Dawson Creek/Chetwynd area of north east British Columbia. Transmission capacity is needed in this area to enhance the quality of service to existing customers and to meet increasing customer load. The Project is BC Hydro's preferred alternative to meet the area's forecasted load growth;

C. The Project consists of three main components:

   i. The construction of the new Sundance Lake Substation (SLS) including the acquisition of 8.15 hectares to facilitate the space requirements of the new substation;

   ii. The construction of a double circuit 230 kV transmission line strung on steel monopoles from SLS to Bear Mountain Terminal (BMT) (60 km) and from BMT to Dawson Creek Substation (DAW) (12 km). A new 33 meter (m) right-of-way is required for the route; in portions where the route parallels existing transmission lines, the required additional width may be less;

   iii. The expansion of BMT including the acquisition of approximately 14 hectares of land to facilitate the additional equipment required for the Project.

.../2

EXHIBIT H-15

D. The Project's expected cost is $222 million and the authorized budget is $257 million with a planned in-service date of April 30, 2014;

E. At the request of BC Hydro, the Commission Panel temporarily suspended the review process on November 30, 2011. The suspension was lifted on April 11, 2012;

F. The Commission held a Procedural Conference on May 2, 2012 in Vancouver, BC to discuss, inter alia, the Scope of the Review of the CPCN Application; Order G-184-11 sets out the Commission's Determinations in that regard;

G. The review of the Application was conducted primarily by way of a written hearing. The adequacy of First Nations' consultation was conducted in an Oral Hearing Phase held from July 9 to July 10, 2012;

H. On October 10, 2012, the Commission issued Order G-144-12, wherein the Commission found the Crown's Duty to Consult West Moberly First Nations on the DCAT Project, had not been adequately met to the date of that Order. Order G-144-12 Directive 2 states:

"The Commission will grant a CPCN to BC Hydro for the DCAT Project, as set out in the Application as Alternative 1, subject to the following conditions:

(a) Within 180 days of the date of this Order, BC Hydro shall file with the Commission evidence of further consultation, as directed in the accompanying Decision.

(b) West Moberly First Nation[s] will have 10 days from the date of the filing of the evidence to file a written response.

(c) BC Hydro will then have 7 days from the date of the filing of West Moberly First Nation[s'] response to file a written reply.

The Commission will review the submissions and, if the further consultation is determined to be adequate to meet the Crown's duty to consult, as set out in this accompanying Decision, the CPCN will be granted."

I. Order G-144-12 also includes Directive 5 which states:

"The revision to section 8.3 of the Terms and Conditions of the Electric Tariff as proposed by BC Hydro is not approved at this time. The Panel may accept the proposed changes subject to receipt of the following clarifications:

(a) BC Hydro is to specify how a new customer's load is to be allocated between Tariff Supplement 6 and the Electric Tariff for the purpose of the deposit/contribution calculation.

(b) BC Hydro is to provide revised amended language for the Electric Tariff section 8.3 which specifically indentifies each section of Tariff Supplement 6 that is applicable to System Reinforcement."

J. On April 4, 2013, BC Hydro filed its Compliance Filing to Directives 5 (a) and (b) of Order G-144-12. In relation to Directive 2(a), BC Hydro states "[t]he potential for double counting can be eliminated by applying the customer's estimated revenues first to the calculations in respect of transmission System Reinforcement, and then any unused portion of the revenues would be eligible to cover BC Hydro's Contribution to the distribution Extension";

K. On April 8, 2013, BC Hydro filed its Compliance Filing to Directive 2 of Order G-144-12 to provide evidence of further consultation with West Moberly First Nations;

L. Also on April 8, 2013, West Moberly First Nations filed its written response to BC Hydro's April 4, 2013 Compliance Filing;

M. The Commission has considered BC Hydro's Compliance Filings and the submission of West Moberly First Nations and finds that BC Hydro has complied with Directives 2, 5(a) and 5(b) of Order G-144-12.

NOW THEREFORE the Commission orders as follows:

1. For the reasons set out in Appendix A to this Order, the Crown's Duty to Consult with the West Moberly First Nations on the DCAT Project has been adequately met, to the date of this Decision.

2. The Commission grants a Certificate of Public Convenience and Necessity for the DCAT Project, as set out in the Application as Alternative 1.

3. BC Hydro must file with the Commission semi-annual updates on the actual Project schedule and costs with a comparison to the plan as set out in the Application and any variances the Project may be encountering. The semi-annual progress reports will be filed within 45 days of the end of each reporting period.

4. BC Hydro must file a final report within six months of the end or substantial completion of the Project. The final report is to include a reconciliation of actual and anticipated Project costs as set out in the Application and provide an explanation of any material costs in excess of $257.4 million.

5. BC Hydro is directed to recalculate the deposit/contribution requirement under Tariff Supplement 6 and, if applicable, the Electric Tariff, for each DCAT customer and file the revised calculation with the Commission within 30 days of this Order.

6. BC Hydro's revised section 8.3 of the Electric Tariff as shown in BC Hydro's April 4, 2013 Compliance Filing, and as directed in Order G-144-12, Directives 5 (a) and (b) is approved.

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of April 2013.

BY ORDER

Original signed by:

L.A. O'Hara
Panel Chair/Commissioner

INFO BULLETIN

Nov 13, 2013

Dawson Creek-Chetwynd area transmission line construction begins

VANCOUVER – BC Hydro has started construction on a major transmission upgrade in the South Peace region that will help provide cost-effective, reliable power to the growing natural gas industry.

BC Hydro has begun right-of-way clearing and site preparation for the Dawson Creek-Chetwynd area transmission project that will employ 55 to 110 workers during construction. The new transmission line will double the electricity capacity in the region and is expected to begin delivering power in 2015.

Some facts about the project

Over the next 10 years, the annual rate of load growth in the South Peace is expected to be 10 times greater than the growth forecast for BC Hydro's entire system.

The Dawson Creek-Chetwynd Area transmission project includes:

- A new substation at Sundance Lake located 19 kilometres east of Chetwynd near Highway 97;
- A new 60-kilometre, double circuit, 230-kilovolt transmission line between the new substation and Bear Mountain Terminal, located about 12 kilometres west of Dawson Creek;
- A new 12-kilometre, double circuit, 230-kilovolt transmission line to connect Bear Mountain Terminal to the existing Dawson Creek Substation; and
- Expansion of Bear Mountain Terminal to a full substation and the expansion of Dawson Creek Substation.

The British Columbia Utilities Commission approved the project, issuing a 'certificate of public convenience and necessity' in April 2013.

In 2012, BC Hydro released a cost estimate range of $190 to $300 million during the planning phase. The cost estimate listed in BC Hydro's most recent Service Plan was $255 million. The latest detailed project cost estimate is $296 million.

The revised estimate reflects an increase in the cost of construction resources, like labour and material, a redesign of poles to improve safe work procedures in future, and additional project consultation requested by the Commission.

For more information please contact:

BC Hydro Media Relations

p. 604 928 6468

“Appendix 4”

BRITISH COLUMBIA

SEP 18 2012

Ref. 70973

Mr. Charles Reid
President and Chief Executive Officer
BC Hydro
18th Floor – 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Mr. Reid:

Re: Kleana Power Corporation's Proposed Hydroelectric Project on the Klinaklini River

Further to the enclosed June 10, July 3 and October 15, 2008 letters from my predecessor, Mr. Richard Neufeld, to Mr. Fred Glendale, Chief Councillor of the Da'naxda'xw/Awaetlala First Nation, I write to direct the British Columbia Hydro and Power Authority to enter into negotiations with Kleana Power Corporation with respect to their proposed hydroelectric project on the Klinaklini River.

As my predecessor stated, any resulting Electricity Purchase Agreement (Agreement) would be subject to review and approval of the British Columbia Utilities Commission to ensure the Agreement is in the interest of BC Hydro's ratepayers. One of the main considerations would be the price of the electricity. I direct that you enter into good faith negotiations with this mandate in mind.

Sincerely yours,

Rich Coleman
Minister and Deputy Premier

Enclosures

Ministry of
Energy, Mines & Natural Gas
and Deputy Premier

Office of the Minister

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