FINAL SUBMISSION ON BEHALF OF

THE CLEAN ENERGY ASSOCIATION OF BRITISH COLUMBIA

Re: BRITISH COLUMBIA HYDRO and POWER AUTHORITY

Certificate of Public Convenience and Necessity for the

Dawson Creek/Chetwynd Area Transmission Project

Project No. 3698640
Pursuant to Order G-132-11

August 2, 2012

British Columbia Hydro CPCN for the Dawson Creek/Chetwynd Area Transmission Project ("DCAT")

INTRODUCTION

For the reasons contained in this final submission the Clean Energy Association of B.C.("CEA") supports BC Hydro's ("BCH") application ("Application") to the British Columbia Utilities Commission for a Certificate of Public Convenience and Necessity for DCAT.

The CEA takes no position with respect to the adequacy of BCH's consultations with First Nations or the proposed changes to the Electric Tariff.

The CEA's comments will be addressed at the following topics:

1. **The Need for the Project**
2. **The Appropriateness of the Selected Project Alternative**
3. **The Cost Effectiveness of the Project**
4. **The Migration of the Review Process**
5. **The BCUC's Questions**

1. THE NEED FOR THE PROJECT

The CEA concurs that BCH has demonstrated there is need for the DCAT project to be constructed as soon as possible, in order to

a) Provide stable and reliable service to existing and new customers in the area;

b) Provide for the increasing load from existing customers and also from new industrial customers requesting service;

c) Alleviate constraints in the existing 138 kV transmission system.

2. THE APPROPRIATENESS OF THE SELECTED PROJECT ALTERNATIVE

The CEA agrees that BCH has chosen a Project alternative that is a technically effective way to serve the area loads, that will keep the immediate costs low, and yet will also lead logically into the next stage of system upgrade, which is needed to make an N-1 standard of service possible for all customers in the area.

The CEA also finds that the Project will also serve to advance several of the government's energy objectives for British Columbia, as stated in Section 2 of the Clean Energy Act, namely:

Objective (g) to reduce greenhouse gas emissions - The Project will enable the use of clean non-emitting, renewable electricity to serve the energy requirements of customers in the area.

Objective (h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia - The Project will facilitate the use of non-emitting renewable electricity in place of the burning of fossil fuels.

Objective (k) to encourage economic development and the creation and retention of jobs - The Project will allow the delivery of clean non-emitting and competitively priced electricity to BC industries which will enable them to compete effectively world-wide.

3. THE COST EFFECTIVENESS OF THE PROJECT

The CEA agrees that BCH has chosen the alternative with the most reasonable cost that can still accomplish the upgrading of the area service in a reasonable staged manner, in keeping with the anticipated growth of the load in the area.

4. THE MIGRATION OF THE REVIEW PROCESS

The process for the review of the Application has migrated into a number of areas that while perhaps interesting from a general public policy point of view, don't have anything to do with the Application. Chief among these are:

a) Whether the Project is a transmission system reinforcement/expansion or extension?

b) Whether industry in this Province can be forced to use self-produced energy i.e. natural gas or self-generate electricity rather than purchase electricity from BCH in accordance with the existing tariff?

c) Whether and when BCH has an obligation to serve customers requesting service.

Although the CEA's detailed positions on these and other matters are set out below, in brief the Application is no different than other relatively recent applications to the BCUC for the Vancouver Island Transmission Reinforcement/Sea Breeze VIC ("VITR") the Interior Lower Mainland ("ILM") or Central Vancouver Island ("CVI") transmission projects. No one in these regulatory processes expressed any interest in migrating into the issues described above. Certainly parties in BCUC proceedings should not be shackled by precedent or from positions previously taken but the facts or valid reasons for change have to exist.

In this instance the facts don't warrant a departure from the analytical framework that the BCUC used in VITR, ILM and CVI. In anticipation of the positions that some interveners may take in their final submissions, the only reason that there has been a migration is because there is a perception that the natural gas industry in British Columbia has a readily available supply of natural gas that can be used to produce natural gas.

No one has ever denied the forest products industry access to electricity supplied by BCH because this industry has access to trees or wood-waste in the forest that can be used to produce energy or to the coal mining industry because of its access to coal.

BCH and its regulator the BCUC are not in the business of rationing the supply of electricity or directly or indirectly telling any industry what technology to use or how to best deploy its capital.

VITR, ILM, and CVI

A thorough review of the BCUC's decisions with respect to VITR, ILM and CVI indicate that none of these projects were considered in the context of the BCUC's Utility System Extension Test Guidelines. The basic physical attributes and requirement for these projects are:

1. **VITR**[1] "By Application dated July 7, 2005, BCTC applied pursuant to Sections 45 and 46 of the UCA for a CPCN for VITR to reinforce the transmission system serving Vancouver Island and the southern Gulf Islands. As described in the Application, VITR would consist of replacing one of the existing 138 kV transmission lines between BCTC's ARN Substation in South Delta and BCTC's VIT Substation in North Cowichan with a new 67 km, 230 kV transmission line with a capacity of 600 MW. BCTC proposes building the project entirely within the existing 138 kV ROW…".

   "It has been known for some time that an upgrade to Vancouver Island's electricity supply system is needed. Several solutions to Vancouver Island's supply problem, including both transmission and generation alternatives, have been proposed."

2. **ILM**[2] "The ILM Project consists of a new 500 kV ac transmission line ("5L83") from the Nicola substation ("NIC") near Merritt to the Meridian substation ("MDN") in Coquitlam, a series capacitor substation near the mid-point of line, and 500 kV single circuit terminations at NIC and MDN. The new line would parallel an existing 500 kV ac transmission line for most of its length. The ILM Project is estimated to cost $602 million ($2014) and is scheduled to enter service in October 2014 (Exhibit B-1, pp. 6-7).…"

   "…The need to reinforce the ILM grid and increase its transfer capability has been discussed by BCH and BCTC for a number of years."

3. **CVI**[3] "BCTC states that the CVI Project comprises the construction of a new transmission line that will connect the existing 230 kV transmission line between Dunsmuir substation ("DMR") and the Sahltam substation ("SAT") with the existing 138 kV transmission system in the vicinity of Nanaimo, and will terminate at a new Harewood West substation ("HWW") to be located in close proximity to the existing 138 kV transmission line connecting Vancouver Island Terminal ("VIT") and Jingle Pot substation ("JPT') approximately 5 kilometers ("km") south of JPT (Exhibit B-1, Appendix A, p. 16).

   BCTC states that, in addition to the new 230 kV Injection transmission line and the new substation, it will carry out necessary modifications to the Lantzville substation ("LTZ") and will purchase sufficient land adjacent to the 230 kV (2L123/128) transmission lines

---

[1] British Columbia Transmission Corporation, "An Application for a Certificate of Public Convenience and Necessity for the Vancouver lsland Transmission Reinforcement Project", July 7, 2006, pages 1 and 3.

[2] British Columbia Transmission Corporation, "An Application for a Certificate of Public Convenience and Necessity for the Interior to Lower Mainland Transmission Project page 2

[3] British Columbia Transmission Corporation, "Certificate of Public Convenience and Necessity, Central Vancouver Island Transmission Project", December 10, 2008 pages 3 and 12

> for a future 500/230 kV transformation substation, the Nanaimo River substation ("NAR"), that will be required when the 230 kV transmission lines are converted to 500 kV operation.
>
> BCTC states that both CVI and SVI have experienced significant load growth over the last several years resulting in the transmission system supplying CVI communities now operating at to close to its maximum rated capacity under normal operating conditions. Under any one of several potential outage conditions during a peak load period, the transmission facilities in the CVI system could experience significant overloads. Consequently it is necessary to upgrade the transmission system as soon as possible…"

The Project and the need for it are fully described in the Application and there is no need to set it out in this submission. It is remarkably similar to VITR, ILM and CVI in that it is an upgrade, expansion, reinforcement or call it what you like but it is not an extension to the BCH transmission system that requires the application of the Utility System Extension Test Guidelines and in particular section 6.2, "Contributions in Aid of Construction".

These contributions are not to be confused with the payments a new customer may be required to make under Electric Tariff Supplement No. 6, Appendix 1 for "System Reinforcement", which specifically does not include generation[4], or the security requirements that are applicable even if a new customer doesn't make a payment for System Reinforcement. These topics are canvassed extensively with respect to the five natural gas electrification load customers in the Information Requests[5] and BCH's Final Written Submission[6]

Natural Gas Used to Produce Natural Gas

While it is an intervener's right to explore the alternatives to DCAT that BCH has examined, to point out BCH's failure to examine certain alternatives or to propose new alternatives this right doesn't extend to BCH's customer's use of energy whether they be a residential, commercial or industrial customer unless there is government policy or law to this effect. Although one of the objectives in the Clean Energy Act is to "ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America," it is also an objective that BCH develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility.

The objectives are not contradictory. BCH is to serve new and existing customers while keeping its rates competitive but it is not supposed to pull up the drawbridge for the benefit of existing customers and send new industrial development to other jurisdictions.

In VITR, ILM, and CVI no participant proposed or was it even considered that an alternative to these projects was to require new customers to use another form of energy (e.g. natural gas) other than electricity to meet their energy needs. Under any circumstances this would be a daunting task that would have to take into account many matters such as greenhouse gas and natural gas price risks and a customer's cost of capital.

---

[4] Electric Tariff Supplement No. 6, Appendix 1, definition of "System Reinforcement" page 5

[5] Exhibit B-5, BCH responses to BCUC Information Requests 1.48.1-1.49.1

[6] Section 7.1, page 15

With respect to CVI, on page 17 of the decision, the BCUC said:

"In considering the Application the Commission Panel has taken into account the requirements of the UCA and the government's energy objectives including the need to "develop adequate energy transmission infrastructure and capacity in time required to serve persons who receive or may receive service from the public utility", as well as Sections 64.01 and 64.02 for the achievement of electricity self-sufficiency."

5. BCUC Questions

1. Should the Guidelines apply to TS 6? If so, does TS 6 reasonably reflect the Guidelines?

No. Please see the heading "VITR, ILM and CVI" under which the CEA explains why DCAT is not a system extension. In any event, TS-6 does reasonably reflect the Guidelines, because of the provisions in Appendix 1 that relate to cost recovery and the posting of security for System Reinforcement.

2. The Guidelines recommend that, as a general principle, the costs and benefits to be considered in the analysis of proposed system extensions include "… net revenues from the system extension (i.e. customer payments less revenues to provide for commodity purchases and upstream transmission charges)." (p.32)

2.1 How does this section of the Guidelines apply to the Maximum Offset as calculated in TS 6, Appendix 1, clause 5(c)(ii)?

Appendix 1 of TS-6 is the equivalent to this recommendation. Except that the Customer's responsibility for additions and alterations to "generation plant" (which the CEA interprets to be similar and included in the term "commodity purchases") only comes into effect when the Customer's new or incremental load exceeds 150 MV.A, and only applies to "additions or alterations to existing BCH Facilities."

At page 2-20 of the Application can be found the following:

"Tariff Supplement No. 6 provides for new customers paying the incremental costs for transmission reinforcement undertaken to serve their load to the extent the projected revenue from their future rates do not cover those costs. Customers are also required to post security equal to the revenue they are projected to contribute through rates."

2.2 Assuming it is applicable, what is an appropriate cost for commodity purchases and upstream transmission charges to use in the calculation of the Maximum Offset?

It is not clear what the BCUC intended, in 1996, to include in the cost of upstream transmission charges but presumably these related to third party charges, if applicable.

It is also not clear what the BCUC meant to include in the term "commodity purchases". However, if they intended to include the cost of energy generation, then the appropriate amount would certainly be BCH's average cost of generation. There is no evidence on the record to support a discussion about using the incremental cost of new generation because by Order G-56-12, the BCUC ruled that the appropriateness of rolled in rates, or postage stamp principles and Province wide resource planning issues are out of scope. For example should the incremental cost of new generation be the electricity price at Mid C? The Alberta pool price? The IPP Clean Power Call price? Site C price? These are resource planning matters. Should the prices be adjusted for the location of the new industrial customer's facilities or should the prices be based on the cost of electricity delivered to the Lower Mainland? Should losses be calculated as the Lower Mainland or the Peace River area? These are matters that would be completely contrary to the regulatory practice of postage stamp pricing and would lead to a multitude of other issues of inequity.

3. TS 6, Appendix 1, clause 2 defines System Reinforcement such that it does not include any "additions or alterations to generation plant and associated transmission, or transmission lines at 500 kV and over," unless the new or incremental loads exceed 150 MV.A.

BC Hydro states that "System Reinforcement includes all costs BC Hydro will need to incur to permit its transmission to provide service. It does not include any incremental generation costs incurred to provide service unless the customer load exceeds 150 MV.A. None of the DCAT Project customers has a load exceeding 150 MV.A" (Exhibit B-22, Q102)

3.1 TS 6 states "additions or alterations to generation plant" while BC Hydro refers to it as "any incremental generation costs" include costs for all potential sources of supply including the incremental costs to obtain electric energy from Independent Power Producers if required

3.2 Would it be appropriate to aggregate the five new customers identified in the Application for the purpose of interpreting the definition of System Reinforcement in TS 6, Appendix 1, clause 2, and consequently the inclusion of any "additions or alterations to generation plant" and/or "incremental generation" costs incurred to provide service to the new customer in the System Reinforcement calculation.

Absolutely not. They are separate legal entities that compete with one another, and they will be signing separate legal contracts. They may form joint ventures, limited partnership or some other entities with Asian buyers of LNG. It would be the equivalent of aggregating two competing copper mining companies because their ore bodies are in the same broad geographic area.

3.3 Assuming it is appropriate to aggregate the five customers identified in the Application, what would the appropriate cost be for any "additions or alterations to generation plant" and/or "incremental generation" costs incurred to provide service to the new customers?

Please see the CEA's answer to question 2.2.

4. TS 6, Appendix 1, clause 5(c)(i) requires that the "first year of normal operation" be used to calculate the estimated incremental revenue and incremental operating and maintenance expenses. The System Extension Guidelines state that "… where customer contributions are required, the Commission recommends that the utilities develop a policy which requires at a minimum all customers who attach within the first five years to contribute to system extensions." (p.26) . The Systems Reinforcement definition in TS 6, Appendix 1, clause 2 does not specify a period of time for determining the 150 MV.A load threshold.

4.1 What period of time would be appropriate to ascertain if the 150 MV.A threshold is met; the first year of normal operations, the largest forecast load within five years of the system reinforcement being complete, the full 30-year forecast, or some other point/range of time?

The appropriate answer is as set out in Exhibit B-30, BCH's response to BCUC IR 4.3.1. At any rate BCH is protected from a stranded asset risk by obtaining security.

5. When interpreting System Reinforcement in TS 6, Appendix 1, clause 2, should any subsequent reinforcement costs to the transmission system, such as the F2016 Stage GDAT Project (which is required to provide N-1 service to the new customers) be considered?

No. They are separate projects and it is the five new industrial customers who are going to be paying for N-1 service although they receive only N-O service. If GDAT doesn't go ahead and there is no guarantee that it ever will including the receipt of regulatory approval, they will continue to pay for this inferior service.

The CEA is always concerned about "project creep" when applications for project approval are filed with the BCUC. It is possible to avoid a thorough regulatory review by incrementally

expanding a small project into a large one which may have been the project that should have been subject to the review in the first instance. The CEA does not have this concern about DCAT in particular because the risk being taken is being fully covered by the customers.

5.1 Assuming yes, how should the costs of these subsequent reinforcements be determined in the absence of firm project estimates?

See the response to 5. It is impossible to make any credible estimate. Any estimate would be purely speculative

6. TS6, Appendix q, clause 3(a) states that it is the primary responsibility of the Customer to establish that the provisions of the electrical service by BC Hydro to the Customer's Plant, is in the public interest.

6.1 Have the five customers demonstrated that the system reinforcement is in the public interest?

Yes. All they are required to do is reasonably demonstrate that they are going to make a financial investment in B.C. that complies with all existing and future laws and regulations. Neither BCH or anyone else has the expertise to determine otherwise.

6.2 What public interest issues should the Commission consider in the application of TS 6 in this proceeding?

The same as those that it considered in VITR, ILM, and CVI. It is BCH that is the regulated utility and not the five new customers.

6.2.1 Should consideration be given to the total rate impact including the incremental capital and operating costs associated with project, plus any cost of energy to service the incremental customer loads, or should consideration be limited to the rate impact caused by the incremental customer loads, or should consideration be limited to the rate impact caused by the incremental capital and operating costs only?

BCH would use all-inclusive rate impacts for portfolio analyses in an Integrated Resource Plan but not necessarily for individual project evaluations. Only on an integrated basis can all the necessary factors be included.

6.2.2 Should consideration be limited to the DCAT Project or should consideration also be given to the 2016 Stage GDAT Project which is required to provide N-1 service?

Please see the CEA's answer to question 5.

7. Any other issue related to the Guidelines or the interpretation of the TS 6 that may be applicable to the DCAT proceeding?

No.

.

6. CONCLUSION

For the reasons provided above the CEA supports the Application, agreeing with BCH that the Project fulfills an important need at a low cost to ratepayers, and as quickly as possible, while also serving to advance the government's energy objectives.

The CEA, however, takes no position with respect to the adequacy of BCH's consultations with First Nations or the proposed changes to the Electric Tariff.