BRITISH COLUMBIA UTILITIES COMMISSION

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

AND

AN APPLICATION BY BC HYDRO AND POWER AUTHORITY

Application for Certificate of Public Convenience and Necessity for the Dawson Creek-Chetwynd Area Transmission Project
Project No. 3698640

British Columbia Pensioners' and Seniors' Organization,
Active Support Against Poverty,
BC Coalition of People with Disabilities,
Council of Senior Citizens' Organizations of BC, and
Tenant Resource and Advisory Centre
("BCPSO et al.")

Final Written Submission

August 2, 2012

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Introduction

This is the submission of the British Columbia Pensioners' and Seniors' Organization, Active Support Against Poverty, BC Coalition of People with Disabilities, Council of Senior Citizens' Organizations of BC and the Tenant Resource and Advisory Centre ("BCPSO et al.").[1] BCPSO is a coalition of community organizations representing a diverse and geographically widespread population of BC Hydro's low and fixed income residential ratepayers. Our clients are a ratepayer group with a longstanding history of meaningful participation in BCUC processes and we have, on their behalf, been actively intervening in many of BC Hydro's past applications, including Certificate of Public Convenience and Necessities ("CPCN") such as the one which forms the subject matter of this Application.

In this Application, BC Hydro is applying for approval of a CPCN pursuant to section 46.1 of the *Utilities Commission Act*[2] for the Dawson Creek-Chetwynd Area Transmission Project ("DCAT") intended to address transmission supply constraints in

[1] Please note that BCPSO et al is also known in this proceeding as "BCOAPO et al" as that client organization has changed its name in the year since this application was filed.
[2] *Utilities Commission Act*, R.S.B.C. 1996, c. 473, as amended.

the Dawson Creek and Groundbirch areas based on "past and future anticipated load growth."[3] The DCAT project entails:

a) the construction of

i) a new 230/138 kV substation called Sundance ("SLS") at the intersection between the current 138 kV line from the Chetwynd Substation ("CWD") to Bear Mountain Terminal ("BMT") and BC Hydro's existing 230 kV line system. The land acquisition made in association with this aspect of the proposed project is proposed not only to accommodate equipment necessary to DCAT but also future potential equipment;

ii) two 60 km long 230 kV lines from SLS to BMT; and

iii) two 13 km long 230 kV lines from BMT to the Dawson Creek Substation ("DAW") which will operate at 138 kV;

b) the conversion of BMT from a 138 kV switching station to a 230 / 138 kV substation;

c) the expansion of DAW to add a 138 kV line bay; and

d) the decommissioning and removal of the 138 kV line from SLS to DAW as well as the portion of the 138 kV line from SLS to BMT not required to serve the customer-owned Kiskatinaw Substation. [4]

In addition, BC Hydro is seeking a modification to the Electric Tariff pursuant to sections 58(1) and 61(2) of the *UCA*[5] to allow for the collection of security when large distribution customers seek to add loads to BC Hydro's system of 10 MW or more when this triggers the need for a transmission system reinforcement.

Given the evidence cited below regarding the transmission constraints in the Dawson Creek and Groundbirch area, our clients think it unlikely that any party to this process will argue that BC Hydro need not take any action to address this lack of transfer capability. Our clients do not think it is open to BC Hydro to sit on its hands but neither can they support the Alternative chosen as being in the public interest.

[3] BC Hydro Final Submission, page 1, Section 1.1.
[4] Exhibit B-1, page 1-2 and 4-1.
[5] *Supra* Note 1.

Our clients are concerned by the Utility's decision to put the cart before the horse by applying for approval of the substantial change to the system DCAT is designed to facilitate without recognizing the need to first examine rate design and tariff system issues. Our clients also take issue with the artificial division of this project into two phases, failing to take into account the inextricable nature of its two phases, which link DCAT's already significant costs to ones that have yet to be defined.

Further, BCSPO does not believe that the fairness issues arising from this project have been adequately mitigated. Notwithstanding the uncertainties associated with BC Hydro's forecasts that are meant to justify this project, the $131.5M in security that BC Hydro has secured does not sufficiently cover what is at risk for existing ratepayers.

BCPSO also takes issue with the Utility's approach to the timing and format of the First Nations Consultation in this matter on two bases: first, that the way in which consultation was conducted does not further the goal of reconciliation with the Indigenous people of British Columbia and second, that such an approach significantly increases the regulatory risk and the uncertainty of the project costs.

Finally, our clients note that the timing of this Application was such that the Commission and Interveners with well-established and legitimate reasons for wanting a fulsome regulatory process were, throughout this process, under significant pressure to shorten timelines to accommodate BC Hydro's deadlines.

This submission will follow with sections on project need, cost and alternatives followed by a discussion of the fairness issue and BC Hydro's attempts to mitigate it, including responses to the Commission's questions about Tariff Supplement No. 6. It then discusses the context of First Nations Consultation before concluding that the application as filed is not in the public interest.

Project Need

The existing transmission system in the area has a transfer capability of 150 MW under N-0 system conditions.[6] When an N-1 single contingency requirement is applied it becomes clear that as of the end of 2011, the existing system had a transfer capability of only 70 MW into the Dawson Creek and Groundbirch area.[7]

When BC Hydro filed this Application in July of 2011, the Utility's P50 Load Forecast (without DSM) for the Dawson Creek and Groundbirch area called for very high load growth, in the order of +25% annually between F2010 and F2016. This forecast showed the area's electricity needs growing from 101 MW in F2011 to 306 MW in F2016 followed by a gentler upward trend culminating in an expected load in 2025 of 355 MW.[8]

BC Hydro confirms that the data is consistent with the information from Table 1 on page 82 of 100 of Appendix B of Exhibit B-1. The following table shows the data supporting Figure 2-3.

	Producer (MW)	Other (MW)	Total (MW)
F11	41	60	101
F12	70	65	135
F13	83	70	153
F14	153	71	224
F15	195	73	268
F16	233	73	306
F17	246	74	320
F18	249	75	324
F19	252	76	328
F20	254	77	331
F21	265	77	343
F22	268	78	346
F23	272	79	350
F24	273	79	352
F25	275	80	355

[6] *Supra* Note 3, page 1-1.
[7] *Supra* Note 3, page 2-5.
[8] Exhibit B-5, BCUC IR 1.28.1

This steep increase in forecast load is primarily attributable to an expectation that unconventional gas producers (or "frackers") will use electricity to exploit the local shale gas reserves.[9] According to BC Hydro, the fracker use for electricity in the P50 modeling is based on the expectation that they will use electricity to keep the natural gas pressured both in the field gathering system and at the processing plant(s).[10]

It is important to note that due to a number of factors, the actual distribution load in F2011 was approximately 25 MW lower than initially forecast but at the time of the first round of Interrogatories, BC Hydro was still calling for the F2012 forecast to be back in line with their original projections.[11]

Because of the uncertainty associated with the rate of development of the area's gas reserves and the producer uptake on electricity use for compression as opposed to direct gas-driven compression, BC Hydro also developed High and Low Load Forecast scenarios.[12] However, even under the Low Forecast scenario, the forecast load exceeded the 70 MW N-1 capability in the area by F2011[13] and the 150 MW N-0 capability by approximately 2014.[14]

In November 2011, BC Hydro requested a temporary suspension of the process to allow "time to collaborate with Government and key stakeholders before setting out policy positions on … fundamental issues."[15] According to BC Hydro's application, those fundamental issues included whether rolled in rate principles should apply on their system; whether there should be distinctions made between old and new customers for ratemaking and service level purposes; whether postage stamp rates the N-1 service standard remains appropriate.

[9] *Supra* Note 3, pages 2-6 and 2-10.
[10] *Supra* Note 3, page 2-9.
[11] Exhibit B-6, BCOAPO IR 1.1.1.
[12] *Supra* Note 1, page 2-15.
[13] Exhibit B-5, BCUC IRs 1.33.1 and 1.34.1 and Exhibit B-1, Figure 2.3.
[14] *Supra* Note 1, Figure 2-3.
[15] Exhibit B-19.

Then, in March of this year BC Hydro requested that the Commission reactivate the process and in that request, BC Hydro included an updated load forecast for the area.[16] This new load forecast included some notable changes. First, actual loads for F2011 and F2012 were materially less than forecast in 2010. Second, currently low natural gas prices resulted in a lowering of the forecast up to F2014. However, after F2014 this new load forecast indicates a higher growth in gas producer load through to F2025[17] and calls for 260 MW of load in the area by F2014 as compared to 224 MW in the original forecast.[18]

Even under the updated Low Load Forecast scenario[19], the peak load exceeds the F2012 Forecast and exceeds the 70 MW N-1 capability limit as does the most recent estimate of F2012 load.[20]

To address this imbalance between load and N-1 capability, since F2010 BC Hydro has been requiring that all new loads in excess of 1 MW[21] be interruptible. As a result, the 150 MW revised load forecast for F2013[22] includes 82 MWs of interruptible load[23] for customers who would prefer firm service.

Based on the load forecasts presented, BCPSO concludes that there is an urgent need for additional supply capability in the DCAT area, even when the more conservative assumptions are applied. However, it is clear that there is no certainty regarding future long term loads in the Dawson Creek and Groundbirch areas. In fact, BC Hydro has acknowledged that load growth could be lower than what was projected under the Low Load Forecast scenario if all gas producers chose to use gas compressors.[24]

Apart from the uncertainties BC Hydro has noted regarding future natural gas prices and the development of the Montney Basin as reserves, the ability of gas producers to

[16] Exhibit B-22.
[17] Exhibit B-22, pages 24-26.
[18] Exhibit B-22, page 34.
[19] Exhibit B-22, page 34.
[20] Exhibit B-30, BCOAPO IR 4.2.3.
[21] Exhibit B-30, BCOAPO IR 4.3.2.
[22] Exhibit B-22, page 34.
[23] *Supra* Note 20.
[24] *Supra* Note 1, page 2-15.

choose natural gas versus electric compression represents a material risk to the forecast. Currently the factors involved appear to favour electric compression[25]. However, the advantage does not appear to be so great that a material change in BC Hydro's system expansion and customer contribution policies couldn't potentially have a significant effect on the choice of gas versus electric compression.

[25] Exhibit B-5, BCUC IR's 1.38.4 and 1.43.1.

Project Cost

In the initial Application the P50 cost of the project was set at $219.1 M while the P90 estimate was $254.6 M. These estimates included contingency, capital overheads, interest during construction and inflation, but not the $0.1 M net book value expense for those assets that will be retired as part of the Project.[26]

Then, in the March 2012 Application Update, BC Hydro provided revised P50 estimates of project costs of $222.3M and a P90 estimate of $257.4M.[27]

Project Alternatives

The Original Application

In the July 2011 Application, BC Hydro presented two alternatives. The first was BC Hydro's preferred option, the 230 kV project, and the second involved the construction of the SLS but the line running from that substation to BMT was going to be 138 kV paired with the existing 138 kV line. Also in Alternative 2, at BMT a 110 MVAr SVC would be installed instead of a substation and the DAW would be expanded in a manner similar to BC Hydro's preferred option.[28]

Both of these alternatives had F2014 in-service dates and were presented with the understanding that BC Hydro would then plan and execute a second stage in F2016 involving the construction of additional 230 kV lines and replacement of 500/230 kV transformers[29]. According to BC Hydro's evidence in response to BCOAPO's IR's 1.6.1 and 1.6.2, this second stage is necessary to meet the full 30-year load forecast.

[26] Exhibit B-1, page 4-23.
[27] Exhibit B-1-3, revised page 4-23.
[28] *Supra* Note 1, pp 3-5 and 3-7.
[29] Exhibit B-1, page 3-2 and 3-7

In BC Hydro's original Application, Alternative 1's higher capital cost was presented as justifiable and the basis upon which that valuation was made included its comparatively higher transmission capability and the greater flexibility and reliability this option provides to the local system as well as its lower net present value ("NPV") when the cost of transmission is taken into account.[30]

This apparent NPV cost advantage is not firm and is, in fact, entirely dependent upon the load forecast chosen. The evidence shows that the NPV advantage BC Hydro`s preferred option enjoys over Alternative 2 disappears if the Dawson Creek Areas Load Forecast is reduced by only 15%, a reduction that will occur if Gas Producer Loads are reduced by 20% from the current forecast.[31] Given that the Low Load Forecast is well below 85% of the Base Load Forecast,[32] the risk that this benefit will not materialize is significant. Thus, the load forecast assumptions, particularly over the longer term, are critical to justify the choice of Alternative 1 as the preferred option and our clients remain unconvinced that the forecast relied upon is reasonable in these circumstances.

BCPSO also notes that the higher capability benefit cited for Alternative 1 is only triggered when the 2nd stage, now known as GDAT, comes online. Post GDAT, Alternative 1 allows for 413 MW while Alternative 2 provides a maximum of 386 MW. While GDAT remains unbuilt, which may be for some time given the significant Load Forecast, First Nation Consultation, and Regulatory risks associated with the project, the supply capability spread between the two alternatives favours Alternative 2`s 207 MW versus Alternative 1`s 185 MW.[33]

The Updated Evidence

When BC Hydro filed its updated evidence in March, the utility presented an update on the value of transmission losses based on the modifications to the Electricity Self

[30] *Supra* Note 1, page 3-13.
[31] Exhibit B-6, BCOAPO IR 1.7.2.
[32] Exhibit B-5, BCUC IR 1.33.1.
[33] Exhibit B-6, BCOAPO IR 1.6.4.

Sufficiency Regulation and Special Direction No. 10 to the BCUC. The effect of these changes was to reduce the value of energy in the shorter term[34]. As a result, Alternative 2 now approximately the same present value as Alternative 1 when the original load forecast is used in the analysis. If the updated Load Forecast were used then Alternative 1 would continue to have the lower present value.[35]

In the updated evidence, BC Hydro also provided a comparison of a number of alternate configurations for the transmission system at both stage 1 and stage 2 of its development.[36] Of the five alternatives considered, several proved to be either more expensive than BC Hydro`s preferred option or simply infeasible.[37] Of the two that were not more expensive or impractical, one had various technical/feasibility issues and a later in-service date while the second one only differed from the proposed DCAT project in its approach to Stage 2.[38] As a result, BC Hydro concluded that the proposed DCAT project still represented the best transmission solution.[39]

BC Hydro also assessed a few local gas-fired generation alternatives, concluding that they have a higher net present cost with a lower reliability than their preferred option.[40] Again though, the relative economics depends on the load forecasts used, as the higher forecasts improve the relative attractiveness of DCAT`s economics.[41] In addition, when comparing the relative economics of local gas-fired generation to DCAT, BC Hydro assumed the energy required by the area will come from a gas-fired plant located on the integrated system, a configuration that makes DCAT the more economic option.[42] An alternative approach would be to assume that the energy supplied is from a clean energy source. BC Hydro's response to that suggestion has been to assert that such

[34] Exhibit B-22, page 37
[35] Exhibit B-22, page 50.
[36] Exhibit B-22, pages 38-46 and pages 51-55.
[37] Exhibit B-22, page 72, per Alternatives B3, B4 and B5.
[38] Exhibit B-22, pages 51-53.
[39] Exhibit B-22, page 51.
[40] Exhibit B-22, pages 63 and 68.
[41] Exhibit B-22, page 68.
[42] Exhibit B-22, page 66.

an approach is inappropriate as it introduces distortions based on the different fuel types used to supply the energy needs.[43]

However, there are serious flaws in BC Hydro's insistence upon a gas-on-gas comparison. One of the key arguments put forward by BC Hydro supporting the DCAT alternative over local gas-fired generation options is that the *Clean Energy Act*[44] limits the amount of gas-fired generation that can be used on its system[45] and that there are other places BC Hydro sees as far more advantageous to use this limited resource.[46] In light of BC Hydro's use of this rationale to bolster the case for DCAT as the preferable alternative, it is, in our respectful submission, disingenuous for the Utility to then assume for the purposes of the economic comparisons with gas-fired generation, that the energy supplied to the area for the DCAT option will be sourced from natural gas. If the comparison of the cost of DCAT is made with the two alternate sources of energy, it is the gas-fired alternative that has the lower net present value.[47]

BCPSO concedes that there is clearly a need for increased supply capability in the Dawson Creek and Groundbirch areas but that this need is not necessarily best served by BC Hydro's preferred option. The case for Alternative 1 is entirely dependent upon the load forecast used and with load forecasts lower than BC Hydro relied upon in its initial Application, the case for other alternatives become stronger and those alternatives more attractive from a ratepayer perspective.[48]

Overall, BC Hydro's case for the DCAT project hinges on loads evolving as anticipated in BC Hydro's Base Load Forecast and very little variation is required before ratepayers face the cost stranded assists. BCPSO suggests that an examination of the merits of this Application requires the Commission to determine whether that Load Forecast is reasonable given the significant risks errors pose to ratepayers and a careful,

[43] Exhibit B-30-1, CEC IR's 4.26.3.5 and 4.27.1.
[44] [S.B.C. 2010] c.22.
[45] Exhibit B-22, page 59.
[46] Exhibit B-22, page 69.
[47] Exhibit B-30-1, CEC IR 4.26.3.5 and Exhibit B-30, BCOAPO IR 4.11.3.
[48] For example, Alternative 2 per Exhibit B-6, BCOAPO IR 1.7.2.

meticulous consideration of the trade-offs between costs, reliability, and the potential that this might be a circumstance where BC Hydro's limited ability to use gas-fired generation is best employed.

Conclusion on Need and Alternatives

If the objective of this project was only to meet the reliability needs of existing customers, then more appropriate alternatives are far less expensive and far more cost-effective. The evidence indicates that the cost of serving existing customers ranges from $30M to $60M compared to DCAT's expected $257M and the additional as of yet undefined cost of the necessary GDAT facilities.[49]

"Fairness of Service"

BC Hydro's Proposal For "Securing" the Cost of DCAT

From the outset of this application, ratepayers have raised issues of fairness. Indeed, the very nature of this project – to build large amounts of infrastructure in order to meet a significant forecasted increase in demand resulting from one nascent industry, has the potential to yield extremely unfair results. If, for example, the shale gas fracturing companies were only to pay the industrial rate it would not come close to reflecting the incremental cost resulting from the demand which they have created. The balance would be made up by other ratepayers who have little to no contribution to the forecasted growth which drives this project.

BC Hydro has responded to issues around fairness by requiring security, and not contributions for the DCAT project. BCSPO is not persuaded by BC Hydro's amount of security to address the fairness issues, and raises several issues with the security and offset calculations below.

[49] *Supra* Note 1, page 3-8; and Exhibit B-5, BCUC IR 1.46.1.

There are currently five customers with loads in excess of 10 MW, all of whom are involved in the Shale Gas Fracturing industry (the "Gas Frackers"). Three of these customers take power at transmission voltage and the security will be provided pursuant to Tariff Supplement No. 6 which is an approved tariff applicable to transmission customers that sets out the extent to which a new customer or load is responsible for the costs of additions or alterations to the system.[50]

Given the high degree of uncertainty associated with the load forecast which is driving this project, and to address the risk that future loads may be materially less than forecast, BC Hydro has canvassed the Gas Frackers and requested that they provide security for their pro-rated share of the costs of the project based on their forecast load. [51] That security, amounting to $131.5M, will be gradually refunded to the customers, depending on the actual revenues provided annually. [52]

The current distribution tariff does not contemplate distribution customers providing security for transmission reinforcement so, as part of its current Application, BC Hydro is seeking to make revisions to the Electric Tariff to permit it to require security for the cost of transmission reinforcements from distribution customers in excess of 10 MW and also, if required, recover some of the costs of the transmission reinforcement made necessary by the new load.[53]

Also, in its response to information requests,[54] BC Hydro noted that the Tariff Supplement No. 6 (TS6)

> *[D]oes not expressly deal with the calculation of a customer contribution to system reinforcements in circumstances where the contemplated reinforcements will improve service to existing customers and non-transmission voltage new customers, as well as permit service to the new transmission voltage customers requesting service.*

[50] Exhibit B-22, page 75 - 76
[51] Exhibit B-1, pages 2-18 – 2-19
[52] Exhibit B-22, pages 80-81 and Electric Tariff Supplement No. 6, Appendix 1, pages 7-10
[53] Exhibit B-22, page 2-20
[54] BCUC 4.8.1.1

In other words, TS6 does not specifically deal with the context for the DCAT project.

In the absence of express language dealing with this situation, BC Hydro has sought to discern and apply the plain meaning of the tariff, and have proposed a method of cost allocation based on the percentage of the project that is necessary to achieve the N-1 standard for existing load, with the residual percentage allocated to the new customer(s).

The share allocated to the Gas Frackers is then subject to an offset by BC Hydro, pursuant to the tariff. For purposes of establishing security requirements, each customers' share of this security requirement is based on its share of the load forecast.[55] Using this approach, BC Hydro calculated that the five Gas Frackers should be held responsible for 60% of the project cost ($131.5 M)[56]. This amount was then allocated pro-rata across the five customers based on their anticipated loads[57].

Tariff Supplement No. 6

Tariff Supplement No. 6 ("TS6") is the facilities agreement that must be signed between BC Hydro and a new transmission voltage customer taking electric service from BC Hydro. It outlines the System Reinforcement, Basic Transmission Extension, Transmission Line and customer facilities required to be installed by each party to facilitate the supply of electricity to the customer. TS6 also identifies the amounts to be paid by the customer.

The additional facilities required to provide service to a customer-owned substation consist of: (a) the Transmission Connection, including the Basic Transmission Extension and the Transmission Line; and (b) System Reinforcements of the existing BC Hydro Facilities, which are constructed and owned by BC Hydro. Typically, the

[55] Exhibit B-1, page 2-19
[56] Exhibit B-22. page 82
[57] BCUC 1.47.2

customer must pay any amount of the project cost that exceeds the amount determined by BC Hydro's offset calculation. This offset calculation considers future incremental revenues and costs.[58] A portion of the security is returned annually to customer based on the actual revenues it provides.[59] For customers over 150 MV.A incremental generation costs are also included in System Reinforcements.[60]

The DCAT project consists entirely of System Reinforcement costs. As a result, while the customer is responsible for such costs under the existing TS6, BC Hydro provides an offset towards the costs.[61] In this case, BC Hydro has determined that of the 115 MW increase in N-1 capability resulting from the project, 42 MW is needed to provide service to existing customers leaving 73 MW to service new customers. As a result, the cost of the project attributable to new customers is deemed to be 60% (roughly 73/115) of the overall cost of $219.1 M – or $131.5 M. In contrast, the offset calculation yields a value of $429 M using an estimated combined load for the five customers of 176 MW.[62] Based on this calculation, there is no capital contribution required from the Gas Frackers, rather they will each provide security for their pro-rata share of the $131.5 M.

While TS6 does not expressly deal with the situation where system reinforcements are also triggered by the existing loads and new non-transmission customers, [63] it does address the circumstance where subsequent transmission customers connect to BC Hydro' system and use the transmission connection. [64] In such cases, the new customers are required to pay a share of costs based on their proportion of the total of the Contract Demands. A similar provision also exists with respect to reinforcement costs whereby any payment (i.e., to cover costs in excess of the BC Hydro offset) made by the first customer is recalculated based on the combined loads and an appropriate amount refunded to the first customer. [65] As a result, BCSPO submits that the approach

[58] BCUC 1.40.1
[59] Exhibit B-22, pages 80-81 and Electric Tariff Supplement No. 6, Appendix 1, pages 7-10
[60] Exhibit B-22, page 77
[61] Exhibit B-22, pages 76-77
[62] BCUC 1.48.2
[63] BCUC 4.8.1.1
[64] Tariff Supplement No. 6, Appendix 1, pages 15-16
[65] Tariff Supplement No. 6, Appendix 1, pages 9-10

proposed by BC Hydro whereby responsibility for system reinforcement costs is allocated to existing and new customers based on their proportionate loads is consistent with the principles used in TS6.

However, in BCSPO's submission, there are a number of issues regarding how BC Hydro has applied this principle in determining the portion of the Project costs that are attributable to the Gas Frackers, and in particular the calculation of the BC Hydro's offset to those costs.

Firstly, the treatment of the revenues from the two distribution customers for the purposes of determining the BC Hydro offset and whether or not a capital contribution, rather than a security deposit is required from these customers is problematic. Similar to TS6, the Electric Tariff for distribution customers contains provisions for addressing the cost of distribution system reinforcements regarding transmission system reinforcements, whereby the fee to be charged to distribution customers for distribution expansion/reinforcement is "offset" by anticipated revenues.[66] The result is that the anticipated revenues from these distribution customers is being counted twice – once in the determination of the offset to be provided against distribution system reinforcement costs and then again in the determination of the offset to be provided against transmission system reinforcement costs. This is a serious flaw.

BC Hydro suggests that since these distribution customers are posting security for their portion of the project's cost it is reasonable to include the distribution revenue in the offset calculation.[67] The problem with this rationale is that the revenues are being used twice to offset the cost of adding the customer's load – thereby diluting the protection supposedly being provided to the system's other customers. Proper treatment of these revenues would see them counted only once for purposes of determining offsets –either for transmission reinforcements or for distribution reinforcements, but not for both. In the alternative, the total of each distribution customer's share of <u>both</u> transmission and

[66] BCOAPO 4.17.1
[67] BCOAPO 4.17.3

distribution reinforcement costs could be determined and compared (once) with the anticipated revenues the customer will provide. However, such an approach would require similar treatment of revenues in the offset calculations for both which is currently not the case.

BC Hydro also suggests that the financial impact of not including the distribution customers in the calculation is not material.[68] It is true that if one adjusts the determination of the BC Hydro offset for transmission reinforcement so as to remove the distribution customers, the value of the offset still exceeds the cost of project[69]. Thus, if one were to consider the customers in aggregate, then the offset could be viewed as fully addressing the cost of the transmission reinforcement such that no contributions would be required. However, BC Hydro has firmly stated that Tariff Supplement No. 6 is meant to be applied on an individual customer basis.[70] This means that if the two distribution customers' revenues are used to "offset" distribution system reinforcements, then a financial contribution should be required to support their pro-rated share of the transmission system reinforcements. A further discussion on whether to aggregate the Gas Frackers for the purposes of TS6 is below in the response to the Commission's questions.

Second, BC Hydro has used the original P50 cost of $219.5M to calculate the 60% contribution of the $131.5M security. At the very least they should use the $222.3M P50 estimate from the March 2012 update. BCSPO prefers the more conservative $257.4M P90 estimate from the March update of which 60% is $154.44M.

Third, BC Hydro has determined that load requirements of the existing customers is 112 MW. Since the current system in the DCAT area can only serve 70 MW with N-1 reliability, BC Hydro has attributed 42 MW of the increased system capability from the DCAT Project to existing customers. [71] BCSPO notes that the basis for the 112 MW not

[68] BCOAPO 4.17.2
[69] BCOAPO 4.17.3
[70] Exhibit B-22, page 84
[71] BCUC 1.39.1

totally clear. It is not based on either the load forecast used in the initial Application or the load forecast presented in the March 2012 update. Rather, it is based on an earlier forecast[72] and, as a result, it cannot be reconciled with the either of these load forecasts which were used to support the Project's need. Also, while the response to BCOAPO IR4.2.1.2 states that the 112 MW does not include the existing (i.e. F2011) load attributable to the Gas Frackers, the responses to BCOAPO IR4.2.4 and 4.2.3 suggest that the 86 MW of total load forecast for F2012 (which all Gas Producer loads) is the current equivalent to the 112 MW.

Further, the response to BCOAPO IR4.2.1 indicates that "existing loads" represents all other loads except for the Gas Frackers, including other smaller gas producers, and reflects an F2011 value. This approach is reasonable as it includes in its consideration all loads except those of the Gas Frackers to whom TS6 is proposed to apply, and it reflects existing conditions. Using this approach the F2011 "existing load" is 114.4 MW if one were to use the original DCAT forecast[73] (135 MW less the 20.6 MW associated with the Gas Frackers[74]). As a result, while the genesis of the 112 MW is not clear, the value appears to be reasonable based on the forecast developed at the time of the initial Application.

A third concern about how BC Hydro has implemented its interpretation of TS6 is with respect to the 176 MW of load used to calculate the value for the BC Hydro offset. The approach was questioned by BCUC staff in BCUC 2.19.1. BC Hydro's rationale for using the full 176 MW of new load expected from these customers by F2014 is that once DCAT is completed it will be able to supply this full load under N-0 conditions.[75] However, BC Hydro has also acknowledged that additional facilities will be required to provide these customers (and others) the N-1 reliability standard that is required for the DCAT area.[76]

[72] BCOAPO 4.2.1
[73] BCOAPO 4.2.3
[74] Exhibit B-22, page 5 and BCOAPO 4.2.1.2
[75] BCOAPO 4.16.4
[76] BCOAPO 4.16.4, BCUC 2.19.1 and BCOAPO 4.4.1 & 4.4.2

Given that the 176 MW of load is giving rise to the need for further upgrades after the DCAT project in order to provide the required N-1 reliability conditions, it is inappropriate to include the revenue attributable to the full 176 MW in the determination of the revenue offset. In principle, DCAT can only supply 73 MW of this load at the required N-1 reliability condition. This is the value that should be used in the determination of the BC Hydro offset. The balance of the 176 MW (i.e., 103 MW) is part of what is driving the need for the F2016 Stage 2 GDAT project and should be linked to that project and not DCAT. In order to credibly use the 176 MW in the offset calculation, the cost being offset would have to include both the DCAT and GDAT projects, which is not precisely known at this time. What is certain is that the combined costs would be significantly higher.

Using 73 MW as opposed to 176 MW in the offset calculation results in a value of $175.8 M which still exceeds these customers pro-rated share of the total capital costs.[77] However, as this is the first time that TS6 has been interpreted/applied to such situations it is important, particularly in terms of precedent, to get the principles correct.

In BCSPO's submission, the comparative incremental cost for the purposes of calculating the level of security sough from the Gas Frackers should be equal to the P90 cost ($257.4M) minus the least expensive alternative to serve the load without the Gas Frackers ($60M), resulting in an incremental cost of $197.4M which is significantly higher than the $131.5M secured from the Gas Frackers. Unless the $197.4M difference is covered by security or contributions, ratepayers will be at risk if the uncertain forecasts do not materialize.

BCUC Letter L-35-12

[77] BCOAPO 4.16.5

On June 15, 2012, the Commission issued letter L-35-12[78], outlining specific questions to be addressed in final submissions.

1. Should the Guidelines apply to TS 6? If so, does TS6 reasonably reflect the Guidelines?

BCSPO submits that the Guidelines should apply to TS6. TS6 deals with who is responsible for facilities and costs when a customer seeks supply from BC Hydro, and specifically addresses matters associated with system reinforcement and transmission system extension. These are the same topic areas addressed by the Guidelines, which arose out a generic hearing on electric and gas system extension policies. As BC Hydro seeks to apply their interpretation of TS6, it is useful to refer to the Guidelines in that interpretation.

Arguments could be made that the Guidelines apply only to electric and gas distribution system expansions and related system improvements, given the explanation of critical terms provided in the Guidelines.[79] However, such arguments would overlook the stated purpose of the Guidelines, which is to facilitate a degree of consistency across utilities in terms of their approaches to system extensions and system extension tests.

To the extent that the BCUC seeks consistency across utilities in the approach taken to system extensions, it is reasonable to conclude that the BCUC would similarly seek consistency between the approaches taken for transmission versus distribution system expansions. Also, based on the terminology clarification provide in the Guidelines,[80] it is clear that the references to System Improvements are meant to reflect improvements to both the distribution and transmission systems.

There are several key areas where TS6 does not reflect the Guidelines:

[78] A-31
[79] Exhibit A2-2, page 3
[80] Exhibit A2-2, page 18, Footnote #1

- The Guidelines generally deal with three different types of costs[81]: a) Connection Costs, b) Extension Costs and c) System Improvement Costs. It envisions Connection costs and System Improvement costs (to the extent they are common to all new customer including infill) being recovered through a "connection charge"[82] paid by the customer. In contrast, System Extension costs and project-specific System Improvement costs would be included in the System Expansion test. In BC Hydro's case, TS6 effectively requires the customer to pay for all System Extension costs, referred to in TS6 as the Transmission Connection, and it is only the System Improvement costs ('System Reinforcement' in TS 6) that are subject to a "test" as to how much the customer should pay. This difference is one of the issues raised in the AMPC evidence.[83]

- The Guidelines recommend that the evaluation of system extensions be based on a discounted cash flow evaluation.[84] However, TS 6 uses what the Guidelines characterizes as an "Undiscounted Net Revenue Test."[85]

- The Guidelines call for the System Expansion test to consider net revenues - customer payments net of commodity purchases and upstream transmission costs[86]. In contrast TS6 uses the total customer revenue in its evaluation.

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 determination of the Maximum Offset as calculated in TS 6, Appendix 1, clause 5(c)(ii)?

As noted above, TS6 includes the customer's total revenue in the determination of the offset and does not net out "commodity purchases and upstream transmission." It

[81] Exhibit A2-2, page 3
[82] Exhibit A2-2, pages 18 and 32 (Point #6)
[83] Exhibit C3-10, Appendix A
[84] Exhibit A2-2, page 31 (Point #1)
[85] See Exhibit A2-2, page 10 and TS 6, pages 8-9
[86] Exhibit A2-2, page 32

should be noted that the Guidelines appear to be written from an unbundled utility perspective where the commodity cost and upstream transmission do not form part of the revenue requirement for the utility connecting the customer but rather are "pass through" costs paid to 3rd party transmission service and commodity providers. In contrast, BC Hydro is a fully integrated utility that includes the "upstream transmission" and "commodity supply" functions. Indeed, its transmission system can be viewed as being the "upstream transmission system" that would typically service local distribution utilities.

Given this context, the Guidelines could be applied to BC Hydro and TS6 in one of two ways. The first approach would be to exclude "commodity-related" revenues from the calculation as set out in clause 5 (c) (ii). The second would be to include all revenues but then include in system improvements the incremental cost of generation needed to service the customer's incremental load. TS6 represents a hybrid of these two alternatives in that it includes all revenues but only includes incremental generation costs when the incremental load exceeds 150 MV.A.[87] In order for TS 6 (in its current form) to conform to the Guidelines, the revenue determination for incremental loads of less than 150 MV.A would need to exclude "commodity-related" revenues. From a broader perspective, the Commission would also need to determine which of the two approaches outlined above should be adopted for an integrated utility such as BC Hydro or whether a hybrid approach such as that used in TS6 is appropriate.

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?

As noted in response to Question 2.1 there are two alternatives for applying the Guidelines to BC Hydro's circumstances and TS 6. If Commission were to adopt the first approach, then the revenues associated with the commodity and upstream transmission (i.e., 500 kV) would need to be excluded from the offset calculation. Since BC Hydro is an integrated utility these revenues are not generated through separate charges as is the case for gas distribution utilities. However, it should be possible,

[87] Exhibit A2-2, page 5

using the result of the cost allocation model BC Hydro uses for rate design, to determine the proportion of the revenues from transmission customers that is attributable to generation (i.e. the commodity) and net this amount out of the gross revenue calculation. A similar approach could be used for the 500 kV system (if impacts on it are not considered as part of the costing of system improvements).

If the second approach were to be adopted then BC Hydro would need to establish an acceptable methodology for determining incremental generation (and possibly 500 kV transmission) costs. In the case of generation, BC Hydro already has developed incremental costing approaches which it uses in its rate design.

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 system 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, Q 102)

3.1 TS 6 states "additions or alterations to generation plant" while BC Hydro refers to it as "any incremental generation costs." Do "additions or alteration to generation plant" and/or "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?

The short answer is yes. TS6 was written in the early 1990's when BC Hydro effectively met generation requirements by building new plant (or increasing, through alteration the supply from existing plant). In today's context, BC Hydro meets new generation requirement through a combination of actions that include both alterations to existing plant and purchases from IPPs.

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?

No. TS6 is an Agreement between BC Hydro and an individual customer and should be interpreted in that context. In fact, the Guidelines recommend that extension tests be done on a disaggregated basis.[88]

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

Whether customers are considered on an aggregated or disaggregated basis should not impact the approach used to determining "incremental generation costs". See the response to Question #2.2

4. TS 6, Appendix 1, clause 5(c)(ii) 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?

Contrary to the premise set out in the question, TS6 does establish a 5 year timeframe for considering subsequent customers who make use of the System Reinforcement.[89] However, if one accepts the response to Question #3.2, then customers would not be aggregated for purposes of defining System Reinforcement costs and this question does not come into play. Indeed, TS6 envisions the situation where new customers seek to use the System Reinforcements – which assumes that the capability of the System Reinforcements extends beyond simply serving the "first" customer. In the case

[88] Exhibit A2-2, page 31 (Point #3)
[89] TS6, Section 5 (e)

of transmission, this scenario is a distinct possibility since transmission investments are "lumpy" and tend to create excess capacity. In contrast, BC Hydro's incremental generation costs are typically expressed on a $/kWh or $/kW basis and if they were included in the initial TS6 offset calculation on this basis, there would be no "excess capacity" whose costs should be shared with subsequent users.

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. The Guidelines also require that "estimates are as accurate as possible."[90] Presumably the GDAT Stage of the project was not included as part of the current CPCN because the project definition and consideration of alternatives had not progressed sufficiently for this stage to be clearly defined and costed.[91]

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

The basis for this question is further support as to why the costs of subsequent (yet to be fully determined) reinforcements should not be considered. In the case of the DCAT project, the fact that there will be a subsequent stage did not have an impact on the evaluation of alternatives, as the future selection of a specific alternative for Stage 2 does not impact on the alternative decision for Stage 1.[92] If this had been the case, then clearly BC Hydro would have had to more fully develop both the alternatives for Stage 2 and their associated costs such that an informed (and prudent) decision could be made in the selection of the Stage 1 alterative. As discussed above, the use of 176 MW at N-1 reliability used to calculate the offset is flawed and problematic for this very reason.

[90] Exhibit A2-2, page 32, (Point #4)
[91] Exhibit B-1, page 3-2
[92] Exhibit B-1, page 3-2

6. TS 6, Appendix 1, clause 3(a) states that it is the primary responsibility of the Customer to establish that the provision of 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?

The "public interest" takes into account a wide range social, environmental and economic considerations. Evaluating the impact of constructing/operating the necessary facilities to provide a customer electric service on these factors is generally beyond the capability of the customer and, indeed, it is the utility and not the customer that has majority of the information necessary to make such a determination. This view particularly applies to "system reinforcement" which directly involves BC Hydro's facilities. As a result, whether or not the system reinforcement is in the public interest is becomes part of the BCUC's considerations in granting the CPCN.

In the context of the TS6 requirement for the customer to "establish that the provision of electrical service by BC Hydro to the Customer's Plant is in the public interest", what the customer should be expected to demonstrate is that the facilities it is responsible for (e.g. the Transmission Line and Customer Substation per Figure 1 of TS6) are in the public interest. In BCSPO's submission, the determination of the public interest should take into account issues of fairness to ratepayers, and whether the steps proposed by BC Hydro adequately mitigate the fairness issues. [In our respectful submission they do not.]

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

See the response to 6.1. For the Commission the public interest issues related to TS6 are the same as those it must consider with respect to the overall CPCN Application.

6.2.1 Should consideration be given to the total rate impact including the incremental capital and operating costs associated with the 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 capital and operating costs only?

Consideration should be given to both perspectives. The inclusion of cost of energy to serve incremental loads (as well as inclusion of the higher loads that can now be served as a result of the project) yields a more holistic view of the impact of the serving the new customer. However, limiting the calculation to the incremental capital and operating costs provides some context as to the scope of the project relative to the utility's overall costs. Both perspectives are valid and useful to understand.

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.

In an ideal situation there would have been sufficient information available for the CPCN application to cover both the F2014 and the F2016 project stages. However, as discussed in response to Question #5, this is not the case. Based on the information that is available and the apparent need to proceed expeditiously with Stage 1 in order to improve the reliability for existing customers, consideration should be limited to the DACT Project. However, given this scope for the Application, the loads used in any evaluation of the BC Hydro offset under TS6 should be limited to those that can be adequately supplied with N-1 service by the DCAT project. This point has been discussed above as one of the issues associate with the application of TS6 to the DCAT project.

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

Should the Commission decide that BC Hydro has not applied TS6 (as proposed) properly or that more wholesale changes are needed to BC Hydro's approach to funding system expansion, an issue that arises about the extent to which such changes should be applied to the customers with whom BC Hydro has already has signed electric service agreements,[93] notably the Gas Frackers.

[93] BCOAPO 4.13.1

To the extent BC Hydro's proposals do not represent what the Commission determines to be a reasonable interpretation and application of the existing TS6 agreement, then it is reasonable to expect these customer to abide by any changes the BCUC directs. At issue here is the proper application of existing tariffs.

However, to the extent the Commission directs changes to TS6 in order in order that it be aligned with the Guidelines, such changes should only be applied to new customers who have not yet executed Service Agreements. To apply such changes to those customers with executed agreements would be a form of retro-active rate making which should be avoided by the Commission.

First Nations and the Adequacy of Consultation

On page 26 of its Final Written Submission, BC Hydro correctly states that the Crown's duty to consult with First Nations arises when the Crown (1) has knowledge, real or constructive, of the potential existence of the Aboriginal right or title and (2) contemplates conduct that has the potential to adversely affect it. The scope and content of the duty to consult varies with the circumstances, and is proportionate to the strength of the case supporting the existence of the right or title, and the seriousness of the potentially adverse effect upon the right or title claimed.[94]

However, BCPSO submits that BC Hydro understates the depth of the consultation required in the present case. Here, the West Moberly have an established treaty right to "pursue their usual vocations of hunting, trapping and fishing" throughout the Treaty No. 8 territory "saving and excepting such tracts as may be required or taken up from time to time for settlement, mining, lumbering, trading or other purposes".[95]

[94] *Haida Nation v. British Columbia (Minister of Forests)*, 2004 SCC 73 ("*Haida Nation*") at paras. 35 and 39.
[95] Treaty No. 8, made 21 June 1899, quoted in *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)*, 2005 SCC 69 ("Mikisew") at para. 2.

The Crown is deemed to have knowledge of treaty rights and, in any case, it is clear that BC Hydro did have knowledge of the existence of Treaty 8 in the present case.

Where an Aboriginal right has been established, a low threshold for consultation will be found to be appropriate within the law only where "the breach is less serious or relatively minor" and even in such cases the "consultation must be in good faith, and with the intention of substantially addressing the concerns of the aboriginal peoples whose lands are at issue."[96]

Potential Adverse Effect

BC Hydro submits that the potential for adverse effects from the DCAT project is low. It bases this assessment on the following factors:

(1) In total, 80 percent of the proposed transmission line is located on privately owned farmland, while only 20 percent would be located on Crown land.[97]

Two things must be noted here. First, 20% of the proposed transmission line will be on Crown land. This equates to approximately 15 kilometers of transmission line requiring a 33 meter right of way and the clearing of approximately 130 hectares of trees (plus "additional trees outside the ROW). In addition, construction of the SLS will require the clearing and permanent use of approximately 21 acres of Crown land. The BMT expansion will require the permanent use of approximately 35 additional acres. The amount of additional land required to be permanently occupied by the DAW expansion does not appear to be indicated in the Application.[98]

Second, although 80% of the transmission line ROW will traverse private land, such land has not necessarily been "taken up" in the sense required to exclude exercise of treaty rights. In *Badger*, the Court said:

[96] *Delgamuukw v. British Columbia*, 1997 CanLII 302 (SCC) at para. 168, quoted in *Haida Nation* at para. 40.
[97] BC Hydro Final Written Submission, page 31.
[98] Exhibit B-1, pp. 4-21 to 4-22 and 4-5 to 4-15.

The evidence led at trial indicated that in 1899 the Treaty No. 8 Indians would have understood that land had been "required or taken up" when it was being put to a use which was incompatible with the exercise of the right to hunt. Historian John Foster gave expert evidence in this case. His testimony indicated that, in 1899, Treaty No. 8 Indians would not have understood the concept of private and exclusive property ownership separate from actual land use. They understood land to be required or taken up for settlement when buildings or fences were erected, land was put into crops, or farm or domestic animals were present. …

An interpretation of the Treaty properly founded upon the Indians' understanding of its terms leads to the conclusion that the geographical limitation on the existing hunting right should be based upon a concept of visible, incompatible land use. This approach is consistent with the oral promises made to the Indians at the time the Treaty was signed, with the oral history of the Treaty No. 8 Indians, with earlier case law and with the provisions of the Alberta Wildlife Act itself.[99]

This interpretation of the Treaty No. 8 right is consistent with evidence given in the current proceeding by Chief Willson:

> *… just because it's on private land doesn't mean it doesn't affect our treaty rights. If the private land is not put to incompatible uses, we still have access there.*[100]

Although BC Hydro describes the privately owned land generally as "farmland", it is not clear that all of the private land affected is actually used as farmland or that all farmland is fenced, put into crops or has domestic animals present. However, the evidence suggests it is not. Mr. Slaney testified:

[99] *R. v. Badger*, [1996] 1 SCR 771 ("*Badger*") at paras 53 and 54.
[100] Transcript Volume 2, July 10, 2012, page 566.

> *… just under 50 percent, 46 percent of the route is on anthropogenic surfaces – you know, from cleared fields, to roads, to hard surfaces from rail lines, to those kind of disturbed areas.*[101]

This suggests that significant portions of the private "farmland" are not in active use so as to exclude the exercise of treaty rights. In addition, Chief Willson testified:

> *We can enter into agreements with the land owner to access their lands to hunt and carry on certain things. We've done that before. We have very good relationships with lots of the residences in the Peace country.*[102]

Further, the effects of what occurs on private land are not necessarily limited to private land. Chief Willson testified:

> *Well, if they're building a big infrastructure on private land because they bought the land, and the infrastructure -- the fallout of that expands, spills off into the Crown lands, then there's an impact to us. So we have to have a say what goes on with that because that's a cumulative impact to us.*[103]

Such spillover impacts on wildlife may be especially prominent with the type of infrastructure -- high voltage transmission lines and substations – proposed here.

(2) A large portion of the line would be located parallel to 1L358 and 2L312, and some portions along Highway 97, utilizing part of the road ROW. Where the new line is expected to parallel an existing line, the additional ROW width will be less than what is typically required for new transmission line ROW.[104]

Although the additional ROW will be less than what is typically required for new transmission line ROW, the additional width required is still significant. The existing 138

[101] Transcript Volume 2, page 607.
[102] Transcript Volume 2, page 566.
[103] Transcript Volume 2, page 566.
[104] BC Hydro, Final Submission at page 31.

kV line ROW is generally 18 meters, while the new 230 kV line will require a 33 meter ROW.[105]

(3) Because the line is located in a populated area, underground and overhead utility crossings are already present in the area, as is an existing highway and railroad.

(4) There are major forest service roads, public and private roads and access trails along the route. BC Hydro's preference is to use existing access to the extent feasible. If required, extensions from existing roads and trails will be constructed during the construction of the transmission line.[106]

It does not appear that the number and extent of road extensions required for construction and maintenance of the proposed transmission line have been identified and evaluated.

BC Hydro does acknowledge that there will be some limited impact from the Project on the ability of the WMFN to exercise their treaty rights. These impacts include the potential for some destruction or alteration to fish and fish habitat during the construction, operation and maintenance phases of the Project; limited impact on wetlands (the BMT to DAW section passes through riparian habitat: Exhibit B-1, p.4-8); disruption and possible dispersion of furbearers and game species during construction; disruption in access for trappers, hunters and fishers during the construction and operation phases of the project.[107]

BC Hydro appears to assume that because there have already been significant modifications to the natural landscape in the affected, further modifications will have less of an adverse effect on treaty rights, reducing the depth of the required consultation. This is not correct. As the *de facto* ability to exercise a treaty right dwindles, the more significant additional impacts become. For example, in *Musqueam*,

[105] Exhibit B-1, pages 4-5.
[106] BC Hydro, Final Submission at page 31.
[107] BC Hydro Final Submission, page 31.

the Court noted the significant impact on the Musqueam if the Crown were to sell one of only two large pieces of Crown land remaining within the Musqueam's traditional territory.[108]

Similarly, in *West Moberly*, the Court described the impact of previous development on the Burnt Pine Caribou herd resulting in its near extirpation, and said:

> To take those matters into consideration as within the scope of the duty to consult, is not to attempt the redress of past wrongs. Rather, it is simply to recognize an existing state of affairs, and to address the consequences of what may result from pursuit of the exploration program.[109]

A similar issue arises in the present case: previous development has impacted moose habitat, making it more (not less) important to protect what remains, and increasing the significance of impacts that may otherwise be considered minor. Chief Willson testified:

> *So though there is not an endangered species we are relying heavily on moose and we do know, though the studies that we've done, that the moose habitats are shrinking. So for us it's very important to protect whatever good moose habitat is left out there and to avoid as much impact or – we call them predator highways. And whenever there is a new linear disturbance on the land, that creates a predator highway, instantly, out there. So we try to avoid them as much as possible.*[110]

Further, the WMFN has expressed concern over "piggybacking", where each infrastructure project becomes a justification for the next. Chief Willson testified:

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[108] *Musqueam Indian Band* v. *British Columbia (Minister of Sustainable Resource Management)*, 2005, BCCA 128 ("*Musqueam*") at paras. 66-67

[109] *West Moberly First Nations v. British Columbia (Chief Inspector of Mines)*, 2011 BCCA 247 ("*West Moberly*") at para. 119.

[110] Transcript Volume 2, page 561.

> *… a forest company will go into an area and open it up for development, put in roads, do cut blocks…. Right after they get in there, the oil and gas companies come in and say, "well, hey … we're interested in the area and we want to do some exploration work … we're just going to go on existing roads, infrastructure. We'll put the lease sites in logging blocks." And they'll drill something, and they'll find something interesting. And they'll think, "Well, we have to go 200 meters over, or a quarter section over here. So we have to put in a new road."…*[111]

The DCAT project is specifically designed to encourage, or at least accommodate, this type of piggybacking. That is, the Project is needed primarily to service the anticipated needs of current and future natural gas fracking operations, which will themselves impact WMFN's treaty rights. Although it is correct to say that consultation must be directed at the impact of whatever particular proposal happens to be on the table at the time, failing to consider the impact of known piggybackers may be an error.

> I am therefore respectfully of the view that to the extent the chambers judge considered future impacts, beyond the immediate consequences of the exploration permits, as coming within the scope of the duty to consult, he committed no error. And, to the extent that MEMPR failed to consider the impact of a full mining operation in the area of concern [when the current application was only for bulk sampling and exploration permits, it failed to provide meaningful consultation.[112]

Based on the foregoing, BCSPO submits that BC Hydro has under estimated the depth of consultation required in the present circumstances.

The Consultation to Date

Although BCSPO has not had any direct involvement in the consultation process, a number of issues arise out of the information made publicly available in this process, including:

[111] Transcript Volume 1, pp. 479-480.
[112] *West Moberly* at para. 125.

- The stage at which the WMFN was consulted and the alternatives considered
- The timeliness of WMFN's response/participation in the consultation
- The scope of the studies requested/considered and funded

The duty to consult arises at the earliest stages of the project, when the Crown "contemplates conduct that has the potential to adversely affect" an Aboriginal right. This includes consultation on decisions made at the "strategic planning" level. In many instances, once strategic planning level decisions -- such as decisions regarding patterns of development, the need for infrastructure and form the infrastructure will take – are made, the decisions remaining at the operational level amount to little more than tinkering with the details. This issue was addressed in *Haida Nation* in the forestry context. The Court said:

> The inventories and the timber supply analysis form the basis of the determination of the allowable annual cut ("A.A.C.") for the licence. The licensee thus develops the technical information based upon which the A.A.C. is calculated. Consultation at the operational level thus has little effect on the quantity of the annual allowable cut, which in turn determines cutting permit terms. If consultation is to be meaningful, it must take place at the stage of granting or renewing Tree Farm Licences.[113]

In the present case, it does not appear BC Hydro engaged the WMFN in a consultation process until the Project had entered the "operational phase", where the only outstanding decisions related to the exact route the transmission lines would follow. Even then, it appears the WMFN was presented with only a couple of options to choose between. Chief Willson testified:

> *Right from the very beginning, from the first initial letter that we received, the first initial review, it was already determined that this was going to be a transmission*

[113] *Haida Nation* at para. 76.

line. We were going to -- all we were going to talk about is where we're going to put the transmission line. We never got to talk about, is there alternatives. The possibility of Shell, or one of the proponents, building a co-gen plant to run gas, to burn gas to create energy. We never got to talk about possible geothermal activity. They're drilling wells all over the place out there. And the down hole temperatures in these wells are extremely hot. They can put a geothermal plant out there quite easily. We never had any discussions about any of that kind of stuff. You know, they made a determination that it was going to be a transmission line. So they had already decided they were building a transmission line. Well, that's not consultation. That's: This is what we're going to do. We may adjust it a little bit but how do we start consultation when they've already pre-determined what they're doing?[114]

This testimony was confirmed by Ms. Dutka:

MS. RANA: Q: And this report considers various other ways to meet the needs and avoid the implications of doing nothing, so to speak. Different versions of the transmission line, interconnection with Alberta, and ultimately on the last two pages, wind generation and Site C. These options are discussed briefly in the report and dismissed. Hence the title of "Dismissed Alternatives". Can I ask you if you had any discussion with West Moberly at that meeting about these dismissed alternatives?

MS. DUTKA: A: So again, our discussions at the June meeting with West Moberly focused on the alternatives that B.C. Hydro determined to be, or BCTC at the time, determined to be feasible or seriously contemplated alternatives. The alternatives described in Appendix A of the system planning report were alternatives that, for various reasons, B.C. Hydro determined were not feasible and were not ones that would address the issues in the area, so they were not seriously contemplated.

[114] Transcript Volume 2, pp. 553-554.

MS. RANA: Q: So they were dismissed before you met with the First Nation for the first time.

MS. DUTKA: A: Yes. B.C. Hydro considered these alternatives not ones that would meet the needs.[115]

It appears that BC Hydro has also never seriously considered the possibility that adequate consultation and accommodation of First Nations rights could mean the DCAT project would never be built, or even that the anticipated start date for construction could be delayed.

Ms. Dutka: So, I've talked a little bit earlier today about a couple of particular issues that were identified, seasonal rounds and trails. And talked a bit about what the potential mitigation measures would be for those should we, you know, be able to get some more detailed information about exactly what those impacts on those items might be. We've also started the moose and, you know, provided evidence on the moose, and the horizontal directional drilling. So, these issues that have been identified so far, again, as we've said, we are definitely willing to meet with West Moberly, find out some details about those, and perhaps develop mitigation plans to the extent possible. You know, based on our current timelines, should the project be approved, construction will start later towards the end of this year, and I think for those issues that have been identified, you know, I am optimistic that we will be able to work something out to mitigate any impacts that we do determine may happen.[116]

This is essentially the situation that arose in *West Moberly*. In that decision, the Court said:

[115] Transcript Volume 2, pp. 617-618.
[116] Transcript Volume 2, p. 667.

> MEMPR never considered the possibility that the [First Nation] petitioners' position might have to be preferred. It based its concept of consultation on the premise that the exploration projects should proceed and that some sort of mitigation plan would suffice. However, to commence consultation on that basis does not recognize the full range of possible outcomes, and amounts to nothing more than an opportunity for the First Nations "to blow off steam".
>
> Effectively, MEMPR regarded the petitioners' Treaty 8 right to hunt as subject to, or inferior to, the Crown's right to take up land for mining or other purposes. There are at least two problems with this approach. First, it is inconsistent with what First Nations peoples were told when the Treaty was signed or adhered to. They were given to understand that they would be as free to make their livelihood by hunting and fishing after the Treaty as before, and that the Treaty would not lead to "forced interference with their mode of life". Second, the concept of mining, as understood by the treaty makers would never have included the possibility that areas of important ungulate habitat would be destroyed by road building, excavations, trenching, the transport of heavy equipment and excavated materials, and the installation of an "Addcar system".
>
> When MEMPR entered into the consultation process without a full and clear understanding of what the Treaty meant, the process could not be either reasonable or meaningful. A consultation that proceeds on a misunderstanding of the Treaty, or a mischaracterization of the rights that the Treaty protects, is a consultation based on an error of law, and cannot therefore be considered reasonable.[117]

BC Hydro has also been critical of the timeliness and clarity of WMFN responses to requests for information and meetings. This issue was addressed in *Tsilhqot'in Nation*:

[117] West Moberly at paras. 149 to 151.

> It must be borne in mind that it is a significant challenge for Aboriginal groups called upon in the consultation process to provide their perspectives to government representatives. There is a constant need for adequate resources to complete the research required to respond to requests for consultation. Even with adequate resources, there are times when the number and frequency of requests simply cannot be answered in a timely or adequate fashion.[118]

With respect to the present case, it is fair to say the WMFN is inundated with consultation requests and other referrals. The WMFN identified the number and variety of processes they are currently dealing with in Exhibit C5-13. Additional evidence relating to the volume of referrals and other requests received by the WMFN relating to development in their traditional territories can be found in the testimony of Mr. Muir in Transcript, Volume 1, pp. 472 to 474. In these circumstances, it is hardly surprising the WMFN have a difficult time responding to the numerous requests in a timely fashion.

One of the purposes of the consultation procedure is to identify and assess the potential impacts of a proposal on First Nations' substantive rights. Without appropriate studies, it is difficult to see how these impacts can be identified and quantified. It may fairly be said, then, that the first step in the consultation process is to identify the baseline data that must be collected and the types of studies that must be undertaken to inform the remainder of the consultation and accommodation process. In the present proceeding, BC Hydro and the WMFN do not appear to have yet completed even this first step.

In summary, BCSPO submits that BC Hydro underestimated the depth of the consultation process required in the present circumstances and that, likely as a result of this underestimation, they failed to carry out adequate consultation with the WMFN.

In light of this examination of the law, BCPSO's position remains that the regulatory and project cost risk associated with BC Hydro's inadequate First Nations accommodation

[118] Tsilhqot'in Nation v. British Columbia, 2007 BSC 1700 ("Tsilhqot'in Nation") at para. 1138.

and consultation process with the WMFN in relation to DCAT is significant and not a cost or risk our clients believe should be borne by BC Hydro's ratepayers.

Conclusion

BCSPO has major reservations about this project, and the way in which it has been developed and brought before the Commission. The preferred Alternative is vulnerable to real and significant variations in the Load Forecast, and the failure of the Utility to fully secure the cost differential between a project designed to service existing customers ($30-$60M) and the DCAT's estimated cost ($256.5M) in this project presents a significant and unacceptable risk of stranded assets, the cost of which would be borne not by the Utility's shareholder or the Gas Frackers, but by BC Hydro ratepayers. BCSPO is not persuaded by BC Hydro's calculation of the appropriate costs and offsets to be applied in establishing a security or indeed a contribution from the Gas Frackers. Finally, BC Hydro has failed in our submission to adequately and honourably represent the Crown in its Constitutional duty to consult.

For the reasons listed above, BCSPO cannot support this project as being in the public interest.

All of which is respectfully submitted,

Sincerely,
BC Public Interest Advocacy Centre

[*Original on file signed by:*]

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