YUKON UTILITIES BOARD
(YUB)

ISSUE: **Need, timing and proposed terms and conditions**

REFERENCE: **May 18, 2021 Minister McPhee's letter - Referral of the Electricity Purchase Agreement with Tlingit Homeland Energy LP**

QUOTE: "3. The YUB shall report on, and make recommendations about, the necessity for the Agreement, its timing, and proposed terms and conditions, with particular regard to:

a. The public need for the Agreement under various reasonable electric load forecasts.

b. The effect of the proposed commitments on the rates of customers and the reliability of electricity service provided to customers.

c. The capability of existing and currently committed and expected generation and transmission facilities including thermal generation facilities to provide reliable electric power generation to meet the forecast load requirements in (a) and the effect of the Agreement on this capability.

d. The risks associated with the Agreement, including its potential impacts on YEC and rates for customers and on the reliability of electricity service provided to customers.

e. Evidence that all reasonable alternative options have been considered, and that proposed spending commitments have been selected on reasonable grounds.

f. Whether it is prudent to enter into the Agreement as proposed at this time."

QUESTION:

a) Please provide a summary of how YEC's application meets each item in the enumerated list from the Minister (and in terms of need, timing and with reference to the terms and conditions in the agreement).

b) How do the terms of the agreement, and specifically the conditions precedent in the agreement, affect the Board's review of factors (a) to (f) above?

ANSWER:

(a) and (b)

Part 4 of Yukon Energy's Submission addresses each of the items in the enumerated list from the Minister:

1. Item 3(a) of the Minister's list is addressed in section 4.1 of the Submission, which also includes:
    a. Section 4.1.1 which addresses item 3(c) of the Minister's list: and
    b. Section 4.1.2 which addresses item 3 (e) of the Minister's list.
2. Item 3(b) of the Minister's list is addressed in Section 4.2 of the Submission.
3. Item 3(d) of the Minister's list is addressed in Section 4.3 of the Submission.
4. Item 3(f) of the Minister's list is addressed in Section 4.4 of the Submission.[1]

In summary, Section 4 of the Submission documents the need for the EPA and its prudence under reasonable electric load forecasts.

- The EPA provides 8.0 MW of renewable dependable capacity during the Peak Winter Period (displacing the equivalent of four rented diesels) as well as LTA annual Winter Period renewable energy of 30.8 GWh that is expected to displace between 15.0 and 19.6 GWh/year of LTA thermal generation over the 40 year EPA term.

- The EPA enables the only near-term resource option other than the BESS to provide material added renewable dependable capacity benefits.

- The EPA provides for all required YEC/AEY study and asset development costs (e.g., for required System Upgrades) to be fully funded in advance by THELP at no cost risk to the utilities or Yukon ratepayers.

[1] Section 3 of the Submission also reviews the key terms and conditions for each part of the EPA. These terms and conditions establish the energy and dependable capacity to be supplied to YEC over the 40-year term, and the costs, prices, payment terms and risks for YEC to purchase the energy and dependable capacity provided under the EPA.

- The EPA impacts on ongoing YEC costs and customer rates are tied to actual THELP deliveries of energy and dependable capacity, and mirror or improve on what would be expected to occur with the least cost permanent thermal resource option. The EPA effect on customer rates is materially lower than the option of equivalent renewable SOP IPP renewable supplies.

- The EPA is expected to maintain, and likely to enhance, current service reliability.

- The EPA places on THELP all risks related to development of the Project, including permitting, securing necessary grant funding, capital costs to complete, and schedule (including completing all condition precedents needed for the EPA to come fully into force for development of the Project).

- In the event that the EPA does not proceed, or it proceeds but the Project in-service is delayed, the EPA retains YEC ability to sustain reliable service using existing YIS resources plus rented diesel units as required for dependable capacity requirements.

- The EPA specifies the timelines required for the Project to proceed in order to secure access to these new renewable energy and dependable capacity resources on a timely and cost effective basis.

As reviewed in Section 4.3 of the Submission, the EPA conditions precedent identify initial risks associated with bringing the EPA into legal force. These risks have minimal if any impact on YEC, on the rates for customers, or on the prudence of proceeding with the EPA at this time. If the EPA is unable to proceed due to failure to complete its Conditions Precedent YEC will know this outcome well before the end of 2022, with ample time to proceed with rented diesel options as required for 2024/25 and subsequent years to ensure reliability of service to customers while other permanent renewable options are reviewed and developed. The fact that the Conditions Precedent remain unresolved at this time does not preclude the Board from assessing the EPA as directed by the Minister based on available information as provided by YEC in its Submission.

ISSUE: **Hydro energy from the Atlin hydro expansion project with THELP**

REFERENCE: **Application, page 1, PDF page 4**

QUOTE: "It can provide the Yukon Integrated System ("YIS") at Jakes Corner with 8 MW of winter dependable capacity and 36 GWh/year of long-term average renewable hydro energy if operated throughout the year."

QUESTION:

a) How accurate is the assumption that the renewable hydro energy will be operated throughout the year?

b) If the Atlin hydro expansion project is operated throughout the year, how likely is it that YEC facilities will spill water due to water license restrictions, which would mean that YEC would not generate electricity from that spilled water?

ANSWER:

(a)

The quote indicates that the project can provide LTA energy capability if operated throughout the year and dependable capacity capability during winter. The EPA, however, specifies a commitment for YEC to purchase energy only during the defined Winter Period (January-May, and September-December, inclusive), i.e., the Project will not operate during the Summer unless YEC specifically requests an energy delivery (which is not expected to occur under normal conditions).

(b)

YEC has substantial surplus renewable generation forecast in the summer period such that Atlin energy provided during this period would be expected only to add to YEC facility spill of water without any material added LTA thermal generation displacement during a year. Under the EPA there will be summer energy deliveries only when requested by YEC as justified in the circumstances, with a separate price for any such deliveries equal to 50% of the last YUB approved blend fuel thermal price. YEC would only exercise this option when thermal generation was otherwise required on the YIS in summer. Buying summer energy from Atlin in this case would be cheaper than running YEC thermal assets.

The YEC Submission estimates that LTA winter EPA deliveries will also have some YEC facility spill of water – however, material added LTA thermal generation displacement is also expected to result from these EPA deliveries throughout the 40 year term of the EPA. Please see response to YUB-YEC-1-11 and YUB-YEC-1-12 for additional analysis.

ISSUE: **Project funding**

REFERENCE: **Application, page 1, PDF page 4**

QUOTE: "THELP is proceeding to secure approvals and permits for the Project, and YEC and THELP are collaborating on securing the necessary government funding."

QUESTION:

a) Has YEC or its parent YDC directly or indirectly contributed any funds to the project – e.g., the work to secure funding? Please explain.

b) Will YEC or YDC be providing any funding for the project? Please explain.

c) Please explain how each of the funding sources and amounts (expected to be secured or already secured) will impact both YEC and ratepayers.

ANSWER:

(a)

No. Neither YEC nor YDC have contributed funds directly to the Atlin project. YEC has incurred and will incur costs related to supporting THELP as necessary to secure funding from governments. The amount is expected to be less than $0.050 million.

(b)

Not directly. The exact routing of funding has not been agreed; it is possible that YDC could be involved in the transfer of funds from YG to THELP. YEC will not be contributing funding directly for the Atlin project.

(c)

The total funding for this project is used to effectively provide an acceptable return to the project proponent while ensuring the buyer pays pricing that is at or lower than the cost of thermal alternatives.

ISSUE: **Project description**

REFERENCE: **Application, page 2, PDF page 5**

QUOTE: "The Project is an 8.7 MW hydroelectric facility that expands, but is separate from, the Existing Plant, although it uses the same Surprise Lake storage (expanded with the new THELP Plant) and Pine Creek water flows."

QUESTION:

a) Can both the Atlin hydro expansion project and the Existing Plan (sic) simultaneously operate at full capacity and for extended periods? Please explain with supporting details.

ANSWER:

(a)

It is assumed that the question is referencing the Existing Plant and the Atlin hydro expansion project (the Project) as identified in the EPA.

The Project and the Existing Plant can simultaneously operate at full capacity for extended periods during the Peak Winter Period (PWP) as defined in the EPA (December 16 to end of February); however, water availability and winter storage requirements can limit this capability during other parts of the year.

The Project capability to provide full capacity during the PWP is reviewed in detail in Section 1.1 of Appendix B of the Submission – including reference to estimated water availability to Seller's Plant over 35 water years (Appendix A, Table A2) assuming forecast Atlin BC Hydro load for 2032 at 6.93 GWh (see Table A1). The following is noted in Section 1.1:

- Based on the assumptions adopted for the LTA delivered energy estimates, expected LTA energy deliveries from the Project to YEC during each PWP over the 35 water years would equal at least 14 GWh and be sufficient to enable a full 8.0 MW of capacity to be delivered to YEC at Jakes Corner for 94% of the PWP days, i.e., for 70.5 of the 75 or 76 days in the PWP, which is more than enough days to cover all of the PWP period when minus 30ºC or lower temperature has been recorded at Whitehorse during the PWP period.

- Table A2 of the Submission confirms that the above outcome is expected even when the Surprise Lake reservoir is not full in the prior October (based on the one relevant historic water year), so long as the Existing Plant load requirement is at 6.93 GWh/year or less (load forecast for 2032).[1]

- To assess sensitivity of dependable capacity to possible higher Existing Plant loads, the following have been confirmed:[2]
    - If Surprise Lake is full in the prior October, the ability to provide 14 GWh of delivered energy to YEC at Jakes Corner (and the dependable capacity at 8.0 MW provided for 94% of the PWP days) is retained regardless of possible Existing Plant load level increases examined (up to 9 GWh per year total load).
    - If Surprise Lake is not full in the prior October, it has been confirmed that so long as the Existing Plant load does not exceed 9 GWh/year, water availability is adequate for LTA delivered energy to YEC during the PWP to be at least 12 GWh, which is sufficient to enable a full 8.0 MW of capacity to be delivered at POI for at least 37 full days (with balance of PWP days at 65% of 8.0 MW), i.e., confirmed ability to accommodate at full capacity at least one two-week cold temperature period plus at least 23 additional days if needed.

[1] The forecast LTA deliveries from the Project assume that the load for the Existing Plant to supply the BC Hydro Atlin community load is 6.93 GW.h/yr. based on load forecast for 2032.
[2] Section 7.2(a) of the EPA restricts modifications to the Existing Plant which would have a material adverse effect on Seller's ability to meet these energy deliveries during each PWP.

ISSUE: **Project description**

REFERENCE: **Application, pages 2-3, PDF pages 5-6**

QUOTE: "A 92 km 69 kV new transmission line from a new substation at the new hydro facilities to a new interconnection substation at Jakes Corner, YK with interconnection to the YIS at the existing 34.5 kV ATCO Electric Yukon ["AEY'] facilities ["AEY System"] for transmission to YEC's S-150 substation in Whitehorse."

QUESTION:

a) Please describe whether each of the facilities listed in the quote are regulated or unregulated, and if regulated, whether YUB or BCUC is the regulator.

ANSWER:

(a)

Under the EPA THELP is responsible for the regulatory requirements for all of the Seller's Plant facilities including the 92 km 69 kV new transmission line and substations identified in the quote. It is YEC's understanding that none of these facilities are regulated by either the YUB or BCUC.

The AEY and YEC facilities referenced in the quote are regulated by YUB.

ISSUE: **Project description**

REFERENCE: **Application, page 3, PDF page 6**

QUOTE: "The Project will also include upgrades to the YIS to accommodate the Project's capacity and energy deliveries (primarily involving AEY System transmission upgrades)."

QUESTION:

a) Please describe these upgrades and who will be responsible for the upgrades (YEC or AEY).

b) Where does YEC expect the upgrades to regulated facilities to be included in rates (YEC and/or AEY's rates)?

ANSWER:

(a)

Please see response to YUB-YEC-1-9(a) for current description of upgrades to be done to the YIS. Under the EPA, YEC has overall responsibility for all upgrades done to the YIS; the Interconnection Agreement and Implementation Agreement address YEC arrangements for AEY responsibilities for the upgrades to its part of the YIS that requires upgrades. Overall, YEC is directly responsible for upgrades located at Whitehorse substation S150, at Jakes Corner Interconnection Substation being developed by THELP, and SCADA related upgrades at Atlin hydro expansion facilities to be developed by THELP. AEY will be responsible for upgrades located on the AEY system between Jakes Corner and S150 at Whitehorse.

(b)

The upgrades to regulated facilities of YEC and AEY will be fully funded by THELP and therefore have no impacts on YEC or AEY rates.

ISSUE: **Project options**

REFERENCE: **Application, page 2, PDF page 5**

QUOTE: "Its significantly shorter project development timeline when compared to other greenfield hydro options (reflecting its expansion of TRTFN's existing Atlin hydro project and the feasibility work already completed for the expansion project)."

QUESTION:

a) Please describe and explain the other options referred to in the above quote. In your response, please identify what non-renewable options were explored.

b) Why was the Altin hydro expansion project the preferred option in terms of both the reasons for the project and project cost?

ANSWER:

(a)

Section 4.1.2 of the Submission describes and explains that the other renewable greenfield hydro options referred to in the above quote are the other small hydroelectric project options in Yukon and northern British Columbia examined in the Knight Piesold Ltd. review reported on in (and attached to) YEC's 10-Year Renewable Electricity Plan (see YUB-YEC-1-32, Attachment 1).

The 10-Year Renewable Electricity Plan also reviewed non-renewable options, including replacement of retired diesel units (see Table 4-1 in Submission). The Submission also considered LCOC costs for greenfield new diesel generation (see footnote 16 in the YEC Submission).

(b)

Please see Section 4.1.2 of the Submission which reviews alternative options to the project other than the BESS that is now being developed. The focus was on renewable hydro generation with storage (that could provide dependable capacity) - the Atlin option has a significantly shorter project development timeline compared to other greenfield hydro options, reflecting the factors noted in the above quote.

The following was also noted in Section 4.1.1 of the YEC Submission:

> "The only other alternative identified to date for meeting the capacity shortfall without rented diesels would be to develop additional permanent thermal (diesel) capability beyond the planned replacements of retired units. As reviewed in the BESS proceeding, the development of new permanent diesel plants is not supported by stakeholders and is also not in line with goals outlined in Yukon government's draft "Our Clean Future: A Yukon strategy for climate change, energy and a green economy." As reviewed in Section 4.2 below, EPA impacts on customer rates are designed to mirror or improve upon the impacts to be expected with a permanent thermal generation option."

Dependable capacity for thermal generation was benchmarked against other permanent generation options (i.e., new greenfield diesel) and not against a rented diesel option. As reviewed in section 4.1.1 of YEC's Submission (page 19), the Board in its BESS Report was "…persuaded that only relying on rented diesel generators would be challenging and would not be a reliable way of closing the capacity shortfall gap."[1]

[1] YUB Report to Yukon Minister of Justice - YEC Application for Energy Project Certificate and Energy Operation Certificate Regarding the Proposed Energy Battery Storage System (BESS) Project, June 30, 2021, page 11. A copy of this report is provided at YUB-YEC-1-32, Attachment 2.

ISSUE: **BC Hydro Supply Agreement**

REFERENCE: **Application, page 2, PDF page 5**

QUOTE: **"In 2009 the TRTFN, through an affiliate of THELP, developed a 2.1 MW hydroelectric power station at Atlin, BC, on Pine Creek with hydro storage at Surprise Lake (the "Existing Plant"). The Existing Plant has an existing electricity purchase agreement with BC Hydro to supply BC Hydro load at Atlin until 2033. THELP expects that a further EPA will be negotiated with BC Hydro for supply after 2033."**

QUESTION:

a) Please provide a copy of the agreement referenced above.

ANSWER:

(a)

Please see Attachment 1 to this response. The agreement referenced above is also available from the BCUC at the link provided below:

https://www.ordersdecisions.bcuc.com/bcuc/orders/en/116883/1/document.do

ISSUE: **YIS upgrades**

REFERENCE: **Application, page 3, PDF page 6**

QUOTE: "The Project will also include upgrades to the YIS to accommodate the Project's capacity and energy deliveries (primarily involving AEY System transmission upgrades)."

QUESTION:

a) Please list all expected YIS upgrades and provide a cost estimate for each upgrade, including the amount of added capacity.

b) Please describe where the interconnection metering point will be.

c) Please describe how far down the Tagish Road the AEY line is. Is it a three-phase line? What voltage is that line?

ANSWER:

(a)

Appendix 1 to this response provides AEY's planning level cost estimate for upgrades to the AEY system. These upgrades constitute most of the required YIS system upgrades. Total estimated AEY costs, including for study work to date, are $16.82 million.

Hatch estimates of YEC system upgrade costs total $1.25 million. These include the following allocations: $0.090 million at S150 (new revenue metering and related work), $0.594 at Jakes Corner substation (new revenue metering and related work, new SCADA panel), $0.170 million at Atlin Generating Station (new SCADA panel), $0.190 common costs for all locations (studies, project management, etc.), and 20% contingency ($0.209 million).

The YIS upgrades and related costs remain subject to review at this time. These system upgrade costs are all funded by the Seller, so there will be no impact to Yukon ratepayers.

(b)

The interconnection metering point (i.e., the YEC revenue meter) will be located at the POI located at Seller's Interconnection Substation at Jakes Corner.

(c)

Electrical service on the Tagish Road is provided by AEY via Carcross. Service from Carcross to Tagish is via a 34.5 kV line and from Tagish to Secret Valley Road is served by a single-phase 14.4 kV line that terminates approximately 11 kilometers from Jakes Corner.

Appendix 1: AEY System Upgrades

AEY has provided a planning level cost estimate of $16.8 million with GST (see the table below) for a maximum of 10.575 MW exported at Jakes Corner. The estimated costs include work to upgrade existing line regulator, add two new line regulators, build connection to the new substation at Jakes Corner, provide power quality metering at the PCC, provide protection upgrades, upgrade 40 km of line with 27.2 km of greenfield construction, 13.2 km of build in place construction, DTT from all upstream AEY protection devices to new THELP substation at Jakes Corner, radio communication line with radios at S150, Grey Mountain tower, Jubilee Mountain tower, Carcross closer recloser, Judas Creek reclosers and Jakes Corner substation,

Item	Cost
Prior work	$ 217,000
Construction Services	$ 80,162
Forestry & Access	$ 540,715
Materials	$ 3,300,273
Camp	$ 2,940,000
Distribution Line Construction	$ 3,541,075
Telecom Labour	$ 835,344
Telecom Materials	$ 862,966
Survey	$ 101,587
Health & Safety	$ 52,500
Land Admin	$ 40,000
Land Planning and Environmental	$ 43,810
Engineering	$ 113,181
Contingency	$ 1,826,903
Management Reserve	$ 713,926
Burdens	$ 810,494
Total	$ 16,019,936
GST	$ 800,997
Total w GST	$ 16,820,933
Previous payments	$ 245,000
Intermediate payment	$ 55,000
Remaining	$ 16,520,933

ISSUE: **Moon Lake**

REFERENCE: **Application, page 3, PDF page 6, footnote 4**

QUOTE: "In future the Interconnection Substation could potentially be connected directly to a new 69 kV YIS facility if new transmission through Carcross to a Moon Lake pumped storage hydro facility is developed as proposed in the Yukon Energy 10-Year Renewable Electricity Plan. See Figure 2-2."

QUESTION:

a) Please describe the anticipated cost implications of YEC's relationship with AEY if the Moon Lake project proceeds.

ANSWER:

(a)

In the context of the current EPA review, YEC is not aware of any anticipated cost implications of YEC's relationship with AEY if the Moon Lake project proceeds.

The quote references the potential connection of the Jakes Corner Interconnection Substation to a new 69 kV YIS facility if new transmission through Carcross to a Moon Lake pumped storage hydro facility is developed. If this connection was to occur in the future, YEC would need to make arrangements with THELP to enable the connection to occur at THELP's Interconnection Substation – including required provision of the new POI and revenue meter location.

ISSUE: **Thermal displacement**

REFERENCE: **Application, page 5, PDF page 8**

QUOTE: "As reviewed in Section 3 below, the EPA focuses on energy delivery for the Winter Period (defined as January-May and September-December inclusive). Expected Winter Period deliveries to YEC per calendar year are 30.8 GWh LTA energy and 25.2 GWh firm energy during the lowest water year. Figure 2-3 below shows LTA Winter Project deliveries by month at Jakes Corner, and the resulting LTA YIS thermal displacement benefits of 19.6 GWh/year at forecast 2024 YIS load after considering other existing or expected renewable sources."

QUESTION:

a) If 30.8 GWh is provided year-round and the thermal displacement is 19.6 GWh, what is the cost of the remaining 11.2 GWh?

ANSWER:

(a)

The energy cost is the same for the entire commitment of 30.8 GWh. The unit price is calculated to reflect that not all of this energy will displace thermal. This is clear from the calculations in column A of Table A3-1 of the Submission and further explained in response to YUB-YEC-1-24.

YEC cost savings from EPA or other IPP deliveries relate to the resulting thermal displacement. No YEC cost savings are derived from EPA or other IPP deliveries that do not displace thermal generation.

The referenced long-term average (LTA) 30.8 GWh is for EPA deliveries provided only during the defined Winter Period. It reflects the average deliveries over 35 Atlin water years. The LTA thermal displacement estimated to result from these EPA deliveries reflects the average of 38 YIS water years. Figure 2-4 in YEC's Submission highlights the wide variance over the 38 YIS water years in forecast thermal displacement using 2024 YIS load forecasts.

The estimated LTA thermal displacement was used to develop the EPA energy price to be paid for delivered energy. YEC is required under the EPA to take all of the energy deliveries provided during the Winter Period (i.e., the 30.8 GWh of expected LTA winter deliveries). The EPA price paid per kWh for these deliveries was determined based on the estimated resulting LTA thermal displacement:

- Using $0.19/kWh (2024$) as the expected cost saving for displaced thermal, the 19.6 GWh/year of expected thermal displacement from the EPA winter deliveries were therefore estimated to provide YEC cost savings of approximately $3.72 million per year (2024$).

- The resulting EPA energy price payable for these winter deliveries was set to equal the expected thermal displacement cost savings for YEC, i.e., the average price paid for LTA 30.8 GWh of deliveries equals $0.121/kWh or $3.72 million divided by 30.8 GWh.

Table A3-1 of the Submission provides detailed calculations for the average EPA price payable in 2024$ for the 2024 load forecast ($0.121/kWh) and for the 2035 load forecast ($0.093/kWh). Table A3-2 of the Submission provides the determination of firm and non-firm winter energy prices (2024$/kWh delivered) payable per Section 8.2 of the EPA, based on the calculations in Table A3-1.

ISSUE: **Benefit of winter deliveries**

REFERENCE: **Application, Figure 2-3, page 5, PDF page 8**

QUOTE:

QUESTION:

a) For areas of the blue portions of Atlin deliveries that are above the red line in Figure 2-3, does that mean that YEC would take deliveries when there are no LTA benefits? Why or why not?

ANSWER:

(a)

Yes. YEC will take deliveries under the EPA (as well as under other IPP agreements) when there are no LTA benefits.

This will occur because, under the EPA, YEC is required to purchase all Atlin deliveries during the Winter Period. This requirement reflects both the technical inability to dispatch deliveries on anything less than a multiple day order period, and the Seller inability to accept the financial risks related to payments being provided only when YEC achieves thermal displacement.

The EPA pricing in the agreement is reduced to recognize that certain energy deliveries have no thermal offsets. That is, the EPA energy price was set based on the average LTA thermal displacement expected from winter deliveries. As reviewed in more detail in the response to YUB-YEC-1-11, assuming \$0.19/kWh saving for thermal displacements, the average EPA energy price for 2024 winter deliveries is only \$0.121/kWh rather than \$0.19/kWh – reflecting the ratio of expected LTA thermal displacement to total expected LTA energy deliveries.

ISSUE: **Government grant funding**

REFERENCE: **Application, page 6, PDF page 9**

QUOTE: "Yukon Energy's 10-Year Renewable Electricity Plan assumed government grant funding to support the development of renewable sources that would not otherwise be selected as the lowest cost resources. YEC and THELP are accordingly collaborating on securing government grant funding necessary for the Project to proceed.

Project capital costs have been estimated to date at approximately $206 million. Grant funding of approximately $150 million is being sought from the governments of the Yukon Territory, British Columbia and Canada to support the economics of the Project. Such funding would allow Yukon Energy to purchase energy and capacity from the Project at prices comparable with the lowest cost thermal alternatives, and deliver a reasonable return to THELP."

QUESTION:

a) What are the current "lowest cost thermal alternatives", and what is their cost per megawatt hour?

b) What YEC backup resources will be available to maintain N-1 capacity if THELP's delivery of electricity under the EPA did not occur or were undelivered?

c) What is the minimum amount of thermal generation capacity that YEC will require to maintain N-1 capacity after electricity deliveries under the EPA take effect? How long does YEC expect to have to maintain such thermal generation capacity and from what thermal generation sources? This projection should include YEC's load growth projections for the life of the EPA.

ANSWER:

(a)

"Lowest cost thermal alternatives" has been estimated separately for energy and dependable capacity. The EPA pricing for the current thermal alternative when the Atlin project is first expected (2024) to provide deliveries to YEC assumes the following (see YEC Submission, section 4.1.1 of Appendix B):

- **Energy**: blend fuel 2024 thermal energy generation cost of $0.19/kWh ($19/MWh), based on 90% LNG[1] at 2024 cost of $0.18/kWh and 10% diesel[2] at 2024 cost of $0.30/kWh, before any potential future impact of carbon taxes.

- **Dependable Capacity**: cost for greenfield new diesel generation capital and non-fuel O&M at (2024$) $200/kW-yr. This price is within the bottom end of the range for levelized cost of capacity (LCOC) estimates of YEC levelized cost of capacity (i.e., fixed capital and O&M costs, excluding fuel costs) for a 12.5 MW new diesel generation facility of $175 per kW (2019$) if located at Takhini without any property taxes, and $199.8 per kW (2019$) if located in Whitehorse with related property tax costs (see response to Undertaking #7 in BESS proceeding).[3] The 2019 LCOC costs escalated at 2% per year for inflation to 2024 equal $193 and $220.6 per KW respectively.

Dependable capacity for thermal generation is benchmarked against other permanent generation options (i.e., new greenfield diesel) and not against a rented diesel option. As reviewed in section 4.1.1 of YEC's Submission (page 19), the Board in its BESS Report

[1] LNG fuel price forecast for 2021 GRA was $0.18/kWh – this price is the same as forecast for 2024. The forecast as developed in late 2021 assumed LNG average efficiency for 2019-2021 of 2.63 kWh/litre (vs 2.66 for 2021 GRA), forecast LNG cost of $20.44/GJ (vs. $20.89/GJ for 2021 GRA – assumes increase in commodity price to $3.34/GJ is more than offset by decrease in transportation charge) and energy content of 0.02367HHV GJ/l (vs 0.02309 GJ/l for 2021 GRA).

[2] Average diesel fuel price forecast for 2021 GRA was $0.205/kWh, based on prices in mid-2020. The price forecast for 2024 reflects YEC October 2021 diesel fuel prices (average $0.302/kWh).

[3] Estimates as per response to Undertaking #7 in BESS proceeding, based on 2021 GRA WACC of 4.794% and Midgard estimated costs (2019$) for 12.5 MW new diesel plant with five 2.5 MW units and 40 year life ($2.6 million per MW capex, fixed year 1 non-fuel O&M of $64,500/MW without property taxes and $91,000/MW with Whitehorse property taxes).

was "…persuaded that only relying on rented diesel generators would be challenging and would not be a reliable way of closing the capacity shortfall gap."[4]

(b)

YEC's dependable capacity requirement provides backup for the largest single contingency event (N-1) disruption of generation supply. This currently results in approximately 37 MW of backup based on possible disruption of the Aishihik Generating Station supply. To require additional capacity to back up the EPA resource, or in fact any other resource would effectively require double-redundancy or N-2 contingency planning. However, there are certain risk mitigation protections in the EPA.

Section 4.3 of YEC's Submission reviews risks related to dependable capacity service reliability.

Construction and Commissioning - Section 4.3 of the EPA provides that YEC may proceed to rent diesel generating units for this Peak Winter Period (PWP) if THELP is unable to confirm to YEC on or before June 1, 2024 the availability of Dependable Plant Capacity for the first PWP, and no Dependable Capacity Payment will be payable by YEC to THELP for the first PWP for Dependable Plant Capacity that was already provided by such rented diesels.[5]

Operations - During subsequent operation of the Atlin Project after commissioning the risk that dependable capacity is not provided as planned during a PWP varies materially depending on when the issue is identified as well as its magnitude and duration:

- Available evidence from 35 water years and the SNC Lavalin analysis (see Section 2.1.3 of the YEC Submission) confirms that water availability is not an expected

[4] YUB Report to Yukon Minister of Justice - YEC Application for Energy Project Certificate and Energy Operation Certificate Regarding the Proposed Energy Battery Storage System (BESS) Project, June 30, 2021, page 11. A copy of this report is provided at YUB-YEC-1-32, Attachment 2.
[5] YEC currently relies on rented diesels during the winter period to address N-1 dependable capacity requirement shortfalls on the YIS. In order to proceed with such rentals, YEC typically needs to know by June what diesel rental requirements exist for the subsequent winter. Absent notification by June of a such a requirement, YEC would not be able to have in place during the subsequent winter the needed dependable capacity to address an N-1 event during an extended cold weather period of two weeks. Section 6.2 of the EPA requires as follows throughout the Term: "If Seller becomes aware that it will not be able to provide 100% of the Dependable Plant Capacity Committed for the following Peak Winter Period due to factors other than water availability to Surprise Lake, Seller will provide, as soon as practicable, Notice to Buyer to permit Buyer when feasible to make alternative arrangements."

risk affecting Project ability to provide dependable capacity as required during the PWP.

- During a PWP it is possible that issues with the ice cover of the power canal or other brief disruptions affecting THELP's Plant may result in short term disruptions to the delivery of dependable capacity. Such disruptions are not expected to occur on any frequent basis, and would be unlikely to affect overall YIS service reliability unless they are concurrent with an N-1 event during a cold weather period.

- To address notification of other constraints on THELP's Plant capability regarding dependable capacity, Section 6.2 of the EPA requires as follows throughout the Term: "If Seller becomes aware that it will not be able to provide 100% of the Dependable Plant Capacity Committed for the following Peak Winter Period due to factors other than water availability to Surprise Lake, Seller will provide, as soon as practicable, Notice to Buyer to permit Buyer when feasible to make alternative arrangements."

    - If such Notice is provided with sufficient time (i.e., by June prior to a PWP) YEC would expect to be able to secure rental diesel capacity as required to ensure reliable service for the coming PWP – and the EPA provisions would ensure that this capacity would be excluded from any dependable capacity payments for that PWP.

    - Otherwise, if YEC is unable to secure rental diesel capacity replacement due to lack of time or other inability to secure rentals, there is a risk resulting that YIS would have a N-1 dependable capacity shortfall for the affected PWP. This same risk relates to all of YEC's facilities and is not expected to be a material risk unless there is in fact an N-1 event during a cold weather period during the affected PWP.

(c)

Yukon Energy's 10-Year Renewable Electricity Plan as summarized in Section 4.1.1 of YEC's Submission, in Figure 4-1 and Table 4-1, provides the best available forecast on thermal generation capacity that YEC will require to maintain N-1 capacity after electricity deliveries under the EPA take effect in late 2024. These projections include YEC's non-industrial peak load growth (as relevant for N-1 determinations) forecast to 2041/42 (in Figure 4-1).

Figure 4-1 and Table 4-1 indicate a forecast YIS N-1 capacity shortfall for winter 2024/25 without the Project of 17.2 MW related to non-industrial YIS load.[6] This capacity shortfall forecasts existing YEC and AEY thermal generation capacity of 36.4 MW plus diesel replacements of 12.5 MW (total permanent thermal capacity of 38.9 MW). The capacity shortfall is assumed to be met with rented diesel capacity unless other new dependable capacity is developed.

- Without the Project and Moon Lake pumped storage, this capacity shortfall increases to 27.6 MW by 2027/28 (requiring 16 of 1.8 MW diesel rental units, plus any spares needed to support these units), and then to 41.5 MW by 2030/31 (requiring 24 rented diesel units).[7] Figure 4-1 indicates this capacity shortfall increases further by about 10 MW by 2041/42, based on non-industrial peak load growth and no changes in permanent resource availability. Non-industrial peak load forecasts have not been extended beyond 2041/42 – however, there is clear potential for ongoing further material growth over the balance of the EPA 40-year term to 2064.

- The EPA is expected to reduce this capacity shortfall and diesel rental requirement by 8.0 MW. Rented diesel requirements would be forecast to be reduced accordingly (ignoring any additional requirement for spares):
    - In winter 2024/25, from 16 units to 11 units (reduction of 5 units)
    - In winter 2030/31, from 24 units to 19 units (reduction of 5 units)

- Moon Lake Pumped Storage Project development is projected to provide an additional 35 MW in Phase 1 and a further 10 MW in Phase 2. The 10-Year Renewable Electricity Plan proposed Phase 1 completion in 2028 (resulting in a 10.8 MW capacity surplus in winter 2028/29) and Phase 2 completion in 2031 (when the capacity shortfall would otherwise re-emerge in winter 2031/32). Figure 4-1 indicates that with these resource developments a capacity shortfall would be likely once again to re-emerge after winter 2041/42. The Moon Lake Pumped Storage Project remains today at a very early planning stage, and would require a major level of federal funding support in order to proceed after necessary planning

[6] The forecast is after forecast DSM, the WH2 uprate, diesel replacements and BESS.
[7] YEC also uses Loss of Load Expectation (LOLE) as system capacity planning criteria where the system is planned not to exceed a LOLE of 2 hours/year. The LOLE criterion includes industrial loads as part of the assessment. At the forecast industrial load, however, the LOLE criterion was satisfied in forecast years so long as the single contingency, N-1, criterion was met.

has occurred. The feasibility of this project is expected to be further clarified by the time that EPA deliveries commence.

ISSUE: **Low water sequence**

REFERENCE: **Application, Figure 2-4, page 6, PDF page 9**

QUOTE:

QUESTION:

a) For the assumption for "Average for Low Water Sequence", which is the solid red line in Figure 2-4, explain how likely it is that Atlin can provide contracted electricity deliveries at full levels to YEC if there are low water or drought conditions.

b) Would low water or drought conditions impact Atlin's operations?

ANSWER:

(a)

The LTA winter deliveries from Atlin with the EPA reflect full delivery during winter months each year based on available water year information for the Atlin project (35 years) as provided in Table A1 of YEC's Submission.

Figure 2-4 assumes LTA Atlin deliveries throughout the model range of YIS water years. No model development has been feasible to date to assess potential correlation of a YIS low water sequence with low water conditions at Atlin, and therefore no probability assessment of that possible correlation can be provided at this time.

The EPA energy pricing separates a price for "firm" energy deliveries (the first 25.2 GWh during the Winter Period in a calendar year, based on the lowest recorded Atlin water year) from the price for "non-firm" energy deliveries (all energy delivered above 25.2 GWh during the Winter Period in a calendar year). Row 5 of Table A3-1 in YEC's Submission shows that most of the LTA thermal displacement benefits are secured with the firm energy deliveries:

- 2024 load forecast: firm accounts for 89% of all LTA thermal displacement benefits.
- 2035 load forecast: firm accounts for 95% of all LTA thermal displacement benefits.

Available analysis in Table A1 of Atlin EPA deliveries over the 35 Atlin water years indicates the following for Atlin water years with deliveries less than 90% of the 30.8 GWh/year LTA (i.e., below 27.7 GWh) used in Figure 2-4:

- 2 years below 26 GWh (1978 at 25.2 GWh and 1979 at 25.8 GWh).
- 3 years above 26 GWh, and below 27 GWh (1965 at 26.55 GWh, 1966 at 26.8 GWh and 1985 at 26.9 GWh).
- 1 year above 27 GWh, and below 27.7 GWh (1973 at 27.4 GWh).

(b)

Low water conditions at Atlin are not expected to lower the dependable capacity of 8.0 MW provided by the EPA. As reviewed in Section 2.2 of the EPA Submission, expected energy deliveries during each Peak Winter Period (PWP), based on the Project's Surprise Lake storage and its 35 water years of record,[1] are expected to enable a full 8.0 MW of capacity to be delivered to YEC each year at Jakes Corner for at least 94% of the PWP days, i.e., for 70.5 of the 75 or 76 days in the PWP. This is more than enough days to cover the 20 or less days of the PWP period when minus 30ºC or lower temperature has been recorded at Whitehorse.[2]

[1] See Table A2 of the Submission.

[2] YEC's winter peak non-industrial load forecast assumes -38ºC, with approximately 8 MW load added by an average daily temperature drop below -30ºC. The forecast LTA deliveries from the Project during a PWP as stated apply regardless as to whether the Surprise Lake reservoir is full in the prior October provided that the load for the Existing Plant to supply the BC Hydro Atlin community load is 6.93 GW.h/yr or less as per the load forecast for 2032. See Section 1.1 of Appendix B of this Submission for more details and sensitivity assessments.

ISSUE: **Project capital costs**

REFERENCE: **Application, page 6, PDF page 9**

PREAMBLE: Project capital costs have been estimated to date at approximately $206 million.

QUESTION:

a) On a best estimate basis, provide the capital cost breakdown for this project between generation (production) costs and transmission costs.

ANSWER:

(a)

The Project is being developed by THELP, and YEC is therefore only aware of capital cost estimates and breakdowns as provided by THELP. Section 2.1(d)(iii) of the EPA requires, as a Condition Precedent to be satisfied, by May 31, 2022, that THELP will have submitted to YEC a detailed funding plan that includes independent third party estimates of capital costs as well as sources of grant funding from governments and debt financing third party lenders.

The $206 million estimate (2024$) for Project capital costs reflects information provided to YEC by THELP in spring 2021, with adjustment to reflect late 2021 estimates for YEC/AEY System Upgrade Costs. This estimate included the following (the generation and transmission/substation components include estimates for construction/ procurement, owner's costs, contingencies, escalation and financing costs):

Generation Plant	$136.2 million
Transmission/ Substation Plant	$53.3 million
YEC/AEY System Upgrades	$16.5 million
Total Project Capital Cost	$206 million

YEC understands that the above estimate is being revised by THELP based on review with its owner's engineer and selected contractors.

ISSUE: **Grant funding**

REFERENCE: **Application, page 6, PDF page 9**

QUOTE: "Grant funding of approximately $150 million is being sought from the governments of the Yukon Territory, British Columbia and Canada to support the economics of the Project."

QUESTION:

a) What parts of the project would B.C. government funding cover?

b) What parts of the project would Yukon government funding apply to?

c) What parts of the project would federal government funding apply to?

d) Please describe each of the grants, the amounts of each of the grants, and the current status and completion dates of each of the grant applications.

e) Please explain the funding source for the $56 million in costs for the project not covered by government grants.

ANSWER:

(a), (b), (c) and (d)

The Project is being developed by THELP, and YEC is therefore only aware of THELP's funding source information as provided by THELP or as provided in joint discussions with government grant funders. We are not currently aware of any grant funding being allocated only to specific parts of the project rather than to the overall project. The Yukon government has committed $50 million to the Atlin Hydro Expansion Project. Grant funding to be provided by other governments continues to be under discussion, and details cannot be appropriately provided at this time.

Section 2.1(d)(iii) of the EPA requires, as a Condition Precedent to be satisfied by May 31, 2022, that THELP will have submitted to YEC a detailed funding plan that includes independent third party estimates of capital costs as well as sources of grant funding from each government and debt financing third party lenders.

(e)

YEC understands that THELP is in discussion with the Canadian Infrastructure Bank (CIB) for debt financing related to the Project. YEC does not have further information at this time on other funding sources beyond government grants and CIB.

ISSUE: **Lowest cost thermal alternative**

REFERENCE: **Application, page 6, PDF page 9**

QUOTE: "Such funding would allow Yukon Energy to purchase energy and capacity from the Project at prices comparable with the lowest cost thermal alternatives, and deliver a reasonable return to THELP."

QUESTION:

a) Describe the lowest cost thermal alternatives.

b) What is the cost of the lowest cost thermal alternative?

c) After regular deliveries from the EPA begin, how many rented diesel generators will YEC need to ensure N-1 capacity is maintained going forward?

d) Will the number of such generators increase as the YIS load increases, and if so, by how many?

ANSWER:

(a) and (b)

Please see response to YUB-YEC-1-13(a).

(c) and (d)

Please see the response to YUB-YEC-1-13(c). Until such time as Moon Lake Pumped Storage is in service, the number of rental units required on the YIS is forecast to increase as peak non-industrial load increases, and the Atlin EPA is expected to reduce this number by five units in each year (see response to YUB-YEC-1-13(c)). The Moon Lake Pumped Storage Project is planned in two phases to remove the need for rented diesels for 10+ years.

ISSUE: **YIS system upgrades**

REFERENCE: **Application, page 7, PDF page 10**

QUOTE: "THELP is responsible for all AEY and YEC system upgrade costs needed to connect the Project to the YIS. Final scoping for these upgrades (with planning level cost estimates) is to be included in the Buyer-AEY System Interconnection Study Report that is currently being concluded as part of the Interconnection Agreement between THELP, YEC and AEY."

QUESTION:

a) Does the referenced quote mean all connection costs up to and at Jakes Corner, including substation and metering costs?

b) Does this include upgrades to the AEY transmission system? If so, please describe those upgrades.

c) What are the estimates for each of these connection costs?

ANSWER:

(a) (b) and (c)

THELP is responsible for the cost of design, construction and maintenance of transmission and substation assets at Atlin, from Atlin to Jakes Corner, and at the Interconnection Substation at Jakes Corner. The referenced quote addresses THELP's additional responsibility for all AEY and YEC system upgrade costs needed on the existing YIS for the Project's connection to the YIS, including responsibility for the cost of any additional metering requirement.

AEY and YEC system upgrades as referenced in the quote are upgrades to the existing AEY (Jakes Corner to Whitehorse, including extending existing transmission to the new Interconnection Substation) and YEC (Whitehorse substation S150) transmission systems that are part of the YIS. YEC system upgrades also include facilities required at the

Interconnection Substation (i.e., YEC revenue meter). Please see response to YUB-YEC-1-9(a) for information on these System Upgrades and related estimated costs.

ISSUE: **Starting templates**

REFERENCE: **Application, page 8, PDF page 11**

QUOTE: "The Parties used as a starting template for the negotiation an amalgam of the YEC Standing Offer Program (SOP) EPA and the BC Hydro Independent Power Producer (IPP) Large Project EPA, and certain other commercial principles and basic terms relevant to the Parties."

QUESTION:

a) Please provide copies of the YEC Standing Offer Program EPA and the BC Hydro Independent Power Producer (IPP) Large Project EPA.

b) Does BC Hydro define a "large project EPA"? If so, please provide that definition.

c) To the extent that YEC is able to answer, what were the commercial principles relevant to the parties?

ANSWER:

(a)

Please see Attachment 1 and Attachment 2 to this response.

(b)

Per Attachment 2 to this response, a large project is defined as a Project having a Plant Capacity of 10 MW or more.

(c)

Section 3.4.1 of the YEC Submission summarizes the key principles relevant to YEC that were reflected in the EPA commercial terms.

ELECTRICITY PURCHASE AGREEMENT

BETWEEN

[SELLER]

- and -

[UTILITY]

[PROJECT NAME]

(YUKON STANDING OFFER PROGRAM)

Dated the ___ day of ____, 20__

TABLE OF CONTENTS

[UTILITY]

STANDARD FORM ELECTRICITY PURCHASE AGREEMENT

STANDING OFFER PROGRAM

THIS ELECTRICITY PURCHASE AGREEMENT ("**EPA**") is made as of the __ day of ____, 20__

BETWEEN:

[SELLER], a corporation incorporated under the laws of _____ ("**Seller**")

- and -

[UTILITY], a corporation incorporated under the laws of the Yukon ("**Buyer**")

WHEREAS:

A. The Government of Yukon issued the *Energy Strategy for Yukon* in January 2009 and in October 2015 issued the *Independent Power Production Policy* as reviewed and updated in October, 2018 (the "**IPP Policy**") as part of the strategy's priority action to "update and develop a policy framework for electricity that emphasizes efficiency, conservation and renewable energy". The IPP Policy created a framework for the development of the Standing Offer Program. In support of the objectives of the IPP Policy, the Government of Yukon issued the SOP OIC and, together with the Utilities, developed the SOP Rules;

B. Seller has proposed the development of the Project on the Electrical Grid pursuant to the Standing Offer Program and such Project has been reviewed and approved in accordance with the SOP Rules; and

C. This EPA is being entered into by the Parties in respect of the Project under the Standing Offer Program in accordance with the SOP Rules.

NOW THEREFORE Seller and Buyer agree as follows:

ARTICLE 1
DEFINITIONS, INTERPRETATION AND SCHEDULES

1.1 Definitions and Interpretation

The definitions and certain principles of interpretation that apply to this EPA are set out in Schedule "A".

1.2 Schedules

The following Schedules attached hereto are incorporated into and made a part of this EPA:

Schedule "A"	-	Definitions and Interpretation
Schedule "B"	-	Project Description

Schedule "C"	-	Form of Annual Operating Plan
Schedule "D"	-	System Interconnection Study Report
Schedule "E"	-	Monthly Energy Shortfall Payment
Schedule "F"	-	Termination Payment
Schedule "G"	-	System Interconnection Guidelines
Schedule "H"	-	Joint Operating Procedure
Schedule "I"	-	Delivery Time Adjustment Table

ARTICLE 2
CONDITIONS PRECEDENT AND TERM

2.1 Conditions Precedent

(a) Except as provided in this Section, this EPA has no legal force until the Conditions Precedent described in Schedule "B" are satisfied by Seller or waived by Buyer. The Conditions Precedent may only be waived by Buyer by notice in writing to Seller.

(b) Seller will:

(i) seek to satisfy each of the Conditions Precedent on or before the Condition Date;

(ii) keep Buyer informed of any circumstances which may result in any of those Conditions Precedent not being satisfied in accordance with their terms; and

(iii) promptly notify Buyer upon satisfaction of any of those Conditions Precedent and provide such supporting evidence as may be reasonably required by Buyer.

(c) If the Conditions Precedent are not satisfied or waived on or before the Condition Date, or it becomes apparent that the Conditions Precedent will not, in the reasonable opinion of Buyer, be satisfied by the Condition Date, the Conditions Precedent will be taken to have failed and Buyer shall be entitled to terminate this EPA, in which event each Party shall release the other from any and all claims, damages, costs, expenses or liabilities whatsoever incurred by it and its Affiliates in relation this EPA provided that (i) Seller shall remain liable for all costs incurred by Buyer in respect of the System Interconnection Study Report, System Upgrade Costs or New Interconnection Facilities Costs and (ii) otherwise each Party shall be responsible for its own costs incurred by it in connection with this EPA.

(d) Section 2.1(a) does not apply to this Article 2, Section 3.5 and Articles 10, 11, 12, 13 and 15 which shall be in full force and effect from the date of this EPA.

2.2 Term

Subject to Section 2.1, this EPA shall commence on the Effective Date and continues for the period specified in Schedule "B", unless it is terminated earlier in accordance with this EPA.

ARTICLE 3
CONSTRUCTION AND OPERATION

3.1 Construction and Operation Costs, Liabilities and Actions

Seller will be fully responsible for the permitting, design, engineering, construction, Interconnection, commissioning, operation, maintenance, reclamation and decommissioning of the Seller's Plant and shall be responsible for all costs, expenses, liabilities and other obligations associated with such activities.

3.2 Standard of Construction and Operation

Except as otherwise consented to in writing by Buyer, such consent not to be unreasonably withheld, conditioned or delayed, Seller will ensure that the location, design, engineering, construction, Interconnection, commissioning, operation and maintenance of the Seller's Plant, are and will be carried out at all times during the Term:

(a) in accordance with the description of the Seller's Plant in Schedule "B" and the information in the Application in all material respects;

(b) in compliance with the Project Standards; and

(c) by qualified and experienced individuals.

The Parties shall conduct their respective operations in accordance with the Joint Operating Procedure.

3.3 Project Changes

Without Buyer's prior written consent, not to be unreasonably withheld, conditioned or delayed Seller will not make any change to:

(a) the Seller's Plant as described in Schedule "B"; or

(b) any other aspects of the Seller's Plant or the information in any System Interconnection Study Report completed for Seller's Plant prior to the Effective Date which would require changes by Buyer to the System Upgrades where such change would increase Buyer's liability for any costs or otherwise increase the obligations or risks of Buyer with respect to the Seller's Plant or any other project.

Seller acknowledges that Buyer may require, as a condition of its consent to any change described in this Section, that Seller agree in writing to reimburse Buyer for any reasonable incremental liability for any losses, costs and damages incurred by Buyer or any third party, with respect to the Seller's Plant or any other project, as a result of any change described in this Section. Buyer may also require that Seller provide performance assurance or security to Buyer in order to ensure that Buyer has no financial exposure in respect of such reimbursement obligation.

3.4 Development Progress Reports

Seller will deliver a Development Progress Report to Buyer on each January 1, April 1, July 1 and October 1 after the Effective Date until Seller's COD. Buyer shall be entitled to request such additional information as it may reasonably require from time to time in respect of Seller's development of Seller's Plant.

3.5 Responsibility for Upgrade Costs

Seller will be responsible for and shall pay Buyer for all System Upgrade Costs and New Interconnection Facilities Costs in accordance with the following:

(a) the System Interconnection Study Report sets out Buyer's estimate of System Upgrade Costs and the New Interconnection Facilities Costs. Seller shall (i) pay to Buyer in advance an amount equal to such estimate of System Upgrade Costs and New Interconnection Facilities Costs ("**Upgrade Costs Advance**") and/or (ii) provide such other security in form, substance and amount as may be acceptable to Buyer in its Discretion to secure the obligation of Seller to pay such costs ("**Upgrade Costs Security**"). Buyer shall not be required in any circumstances to accept Upgrade Costs Security except in its Discretion. Buyer shall not be required to perform any work or incur any System Upgrade Costs or New Interconnection Facilities Costs where Buyer determines in its Discretion that the amount of Upgrade Costs Advance it has received together with any Upgrade Costs Security is not sufficient to adequately secure the obligation of Seller to pay all System Upgrade Costs and New Interconnection Facilities Costs and Seller shall forthwith provide to Buyer such additional Upgrade Costs Advance and/or Upgrade Costs Security as may be reasonably required by Buyer;

(b) Buyer will exercise Good Industry Practice to perform, or cause to be performed, the work required in respect of the System Upgrades and the New Interconnection Facilities for the Project. Buyer shall be entitled to draw upon the Upgrade Costs Advance and Upgrade Costs Security from time to time in its Discretion to satisfy any System Upgrade Costs and New Interconnection Facilities Costs as and when incurred by Buyer; and

(c) notwithstanding the estimate of System Upgrade Costs and New Interconnection Facilities Costs provided by Buyer to Seller contemplated in Section 3.5(a) or the amount of any Upgrade Costs Advance and Upgrade Costs Security provided by Seller, Seller shall be responsible for and shall pay Buyer the actual System Upgrade Costs relating to the System Upgrades incurred by Buyer. Following the completion of the System Upgrades and the payment in full by Seller of all System Upgrade Costs incurred by Buyer for such work, Buyer shall release to Seller any undrawn portion of the Upgrade Costs Advance and Upgrade Costs Security.

3.6 Metering

As part of the System Upgrades and New Interconnection Facilities, Buyer will install and maintain an appropriate Meter installation at the POI, and ensure that such Meter is tested and sealed according to any Measurement Canada standards. Seller will allow Buyer to access the Seller's Plant as may be necessary from time to time to install and maintain the Meter at the POI. If there is any dispute regarding the accuracy of the Meter, either Party may give notice to the other Party of the dispute. In that case, the Parties will resolve the matter in accordance with the *Electricity and Gas Inspection Act* (Canada).

3.7 Insurance

Seller will, at its cost, obtain and maintain (a) policies of commercial general liability insurance with a per occurrence limit of liability not less than $5,000,000, and (b) property insurance, with limits of liability and deductibles consistent with those a prudent owner of a facility similar to the Seller's Plant would maintain and those the Facility Lender may require. All commercial general liability policies must include Buyer, its directors, officers, employees and agents as additional insureds and must contain a cross liability and severability of interest clause. All policies of insurance must include a waiver of subrogation in favour of Buyer. All policies of insurance must be placed with insurers that have a minimum rating of A- (or equivalent) by A.M. Best Company and are licensed to transact business in the Yukon and must be endorsed to provide to Buyer 30 days' prior written notice of cancellation, non-renewal or any material amendment that results in a reduction in coverage. Seller will give Buyer a copy of the insurance certificate(s) for the insurance required to be maintained by Seller under this Section not more than 30 days after the effective date of coverage and promptly upon renewal thereafter. Seller will be responsible for the full amount of all deductibles under all insurance policies required to be maintained by Seller under this Section.

3.8 Seller's COD

(a) Except with Buyer's prior written consent, Seller's COD may not occur earlier than 90 days prior to Target Seller's COD.

(b) Buyer will not be required to incur any incremental expense or other liability of any kind to enable Seller's COD to occur prior to Target Seller's COD.

3.9 Change in Target Seller's COD

If the estimated date for completing the System Upgrades or the New Interconnection Facilities as required to achieve Buyer's COD is later than 90 days prior to the Target Seller's COD, Buyer shall provide notice to Seller of such delay and, provided Seller is not responsible for any delay in completing the System Upgrades or the New Interconnection Facilities (including a failure to pay amounts contemplated in Section 3.5), upon Seller's written request that the Target Seller's COD be postponed, Buyer will postpone the Target Seller's COD to the estimated date for completing the System Upgrades and the New Interconnection Facilities plus 90 days.

3.10 No Liability For Delay

Buyer shall exercise reasonable commercial efforts to achieve Buyer's COD prior to Target Buyer's COD. Buyer will have no liability under this EPA for delays in completion of (a) any System Upgrades or the New Interconnection Facilities, or (b) other work undertaken by Buyer or any of Buyer's Affiliates on the Seller's Plant side of the POI, in each case howsoever arising.

3.11 Outages

(a) **Notice of Seller's Outage -** Seller will notify Buyer of any Outages in Seller's Plant, or changes in any such Outages, by delivering to Buyer an Outage Notice or revised Outage Notice:

(i) promptly in the case of a Forced Outage or a Maintenance Outage;

(ii) not less than 90 days in advance of any Planned Outage, or such shorter time period with Buyer's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and

(iii) promptly in the case of any changes to the duration, start time or end time of any Outage.

(b) **Notice of Buyer's Outage -** In addition to Buyer's reporting requirements under Section 4.8(d), Buyer will notify Seller of any Planned Outages that will result in a Buyer's Distribution/Transmission Constraint or changes in any such Planned Outages, by delivering to Seller an Outage Notice or revised Outage Notice:

(i) not less than 90 days in advance of any such Planned Outage, or such shorter time period with Seller's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and

(ii) promptly in the case of any changes to the duration, start time or end time of any Outage.

(c) **Coordination and Scheduling of Outages -** Seller will coordinate all Planned Outages or Maintenance Outages with Buyer's maintenance schedule or other requirements where such schedule or requirements are publicly available or otherwise notified to Seller.

3.12 Annual Operating Plan

On or before October 31 in each year during the Term, Seller will provide to Buyer its Annual Operating Plan, including any required update to the then current Annual Operating Plan, for the 12-month period commencing on January 1 of the next year. Seller will promptly provide Buyer with a revised Annual Operating Plan from time to time upon Seller becoming aware of any expected material change in the original Annual Operating Plan for that period. The Parties agree the Annual Operating Plan is provided for planning purposes and does not guarantee or limit the quantity or timing of Delivered Energy to the POI.

ARTICLE 4
PURCHASE AND SALE OBLIGATIONS

4.1 Energy prior to Buyer's COD

Subject to satisfaction of all obligations of Seller under this EPA, upon the occurrence of Seller's COD but prior to the occurrence of Buyer's COD, Buyer will not be obligated to purchase, or accept delivery from Seller of, any Energy, provided if Buyer does accept, in its sole discretion, delivery of Energy at the POI, Buyer will pay for such Energy accepted by Buyer prior to Buyer's COD in accordance with Section 5.1.

4.2 Energy after Buyer's COD

From and after Buyer's COD for the remainder of the Term, Seller will sell and deliver all Energy to Buyer at the POI and Buyer will, subject to Sections 4.3 and 4.4, purchase and accept delivery of all Delivered Energy. Buyer will pay for Delivered Energy from and after Buyer's COD in accordance with Section 5.1.

4.3 Limit on Delivered Energy and Capacity

Notwithstanding the foregoing provisions of this Article 4:

(a) in any hour, Buyer will not be obligated at any time to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Seller's Plant Capacity in such hour (as measured in KWh) and no amount will be payable by Buyer for Delivered Energy in excess of the Seller's Plant Capacity in such hour, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI;

(b) in any calendar year, Buyer will not be obligated to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Project Energy Volume and no amount will be payable by Buyer for Delivered Energy in any such calendar year in excess of the Project Energy Volume in such calendar year, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI; and

(c) in determining the total amount of Delivered Energy for a year, month, hour or any other time period under this EPA for any purpose, the amount of Delivered Energy in each hour of such time period will not exceed the Seller's Plant Capacity in such hour, even if Seller delivered to the POI Energy in excess of such amounts, or the Seller's Plant was capable of generating Energy in excess of such amounts.

4.4 Distribution/Transmission Constraints

Buyer will not be in breach or default of its obligations under Sections 4.1, 4.2 or 5.1 if Buyer is not able to accept delivery of Energy at the POI as a result of a Distribution/Transmission Constraint. Buyer will have no liability with respect to a Distribution/Transmission Constraint, except as set out in Section 4.8, if applicable.

4.5 Exclusivity

(a) Seller will not at any time during the Term commit, sell or deliver any Energy (or related Environmental Attributes) to any Person other than Buyer under this EPA. Seller will not use any Energy (or related Environmental Attributes) for any purpose whatsoever except for sale to Buyer under this EPA. These prohibitions do not apply if, and for so long as, Buyer is in breach of its obligations under Section 4.2.

(b) Seller shall not be entitled to interconnect a generating facility to the Seller's Plant and transmit electricity via the Seller's Plant to the POI.

4.6 Custody, Control, Risk of and Title To Energy

Custody, control, risk of, and title to, all Energy (including any Delivered Energy exceeding the limits set out in Section 4.3 even where Buyer has not paid for such excess Delivered Energy) shall pass from Seller to Buyer at the POI. Seller will ensure that all Energy delivered to Buyer under this EPA is free and clear of all liens, claims, charges and encumbrances.

4.7 Line Losses

Seller will be responsible for all Line Losses, costs and liabilities relating to the transmission of Energy and other electricity, if applicable, from the POI to the interconnection point between the New Interconnection Facilities and the Electrical Grid. Such Line Losses shall be determined in accordance with the Line Loss Methodology.

4.8 Distribution/Transmission Constraint

(a) If, in any month after Buyer's COD, Seller is unable to deliver Energy at the POI or Seller's ability to deliver Energy at the POI is reduced solely as a result of a continuous Distribution/Transmission Constraint which exceeds 30 minutes in duration and which:

(i) is not caused by a Planned Outage by Buyer of the Distribution System or Transmission System;

(ii) is not caused by an event beyond the reasonable control of Buyer; and

(iii) is not caused by Seller, the Seller's Plant or anything on Seller's side of the POI;

(a "**Non-Permitted Distribution/Transmission Constraint**") then, notwithstanding that Buyer is excused under Section 4.4 from its obligations under Section 4.2, Buyer shall pay Seller, for each calendar month in which the Non-Permitted Distribution/Transmission Constraint has occurred, the Monthly Energy Shortfall Payment calculated in accordance with Schedule "E" less any costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint.

(b) Buyer will not be required to pay any Monthly Energy Shortfall Amount under this Section in any of the following circumstances:

(i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;

(ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure; or

(iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Non-Permitted Distribution/Transmission Constraint occurs.

(c) Seller will maintain accurate and complete Records of all costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint and will report all such costs to Buyer and provide Buyer with all information required to calculate such costs.

(d) Buyer will give Seller notice of all Distribution/Transmission Constraints in each month which individually exceed 30 minutes in duration when it provides its monthly statements in accordance with Section 5.3.

(e) In the event of a Dispute by the Parties in respect of the amount of any Monthly Energy Shortfall Amount, the matter shall be resolved in accordance with Article 12.

4.9 Buyer Dispatch/Turn-Down Right

(a) Buyer may at any time during the Term deliver notice to Seller requiring Seller to Dispatch/Turn-Down and Seller will promptly comply with any such direction except to the extent that any operational, technical or regulatory constraint prevents or limits Seller's ability to comply with such direction.

(b) For each hour of the applicable Dispatch/Turn-Down, Buyer will pay Seller an amount equal to:

(i) the price payable for post-COD Delivered Energy under Section 5.1 multiplied by (A) the aggregate of the duration of the applicable Dispatch/Turn-Down (measured as a fraction determined as the aggregate number of minutes in such Dispatch/Turn-Down period divided by 60) multiplied by (B) an amount equal to the positive difference, if any, of (1) the "Non-Permitted Distribution / Transmission Constraint Hourly Deemed Energy" set out in Table E-1 of Schedule "E" for the applicable calendar month less (2) the amount of Delivered Energy in such hour of Dispatch/Turn-Down (the positive difference being the "**Dispatch/Turn-Down Deemed Energy**"); less

(ii) any costs Seller avoided or, acting reasonably, could have avoided during the period of the Dispatch/Turn-Down.

(c) Buyer will not be required to pay any amount in respect of Dispatch/Turn-Down Deemed Energy under this Section in any of the following circumstances:

(i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;

(ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure;

(iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Dispatch/Turn-Down occurs;

(iv) during any other hour when the Seller's Plant would otherwise not have been operating if there had been no Dispatch/Turn-Down notice; or

(v) where Buyer's requirement for Seller to Dispatch/Turn Down is the result of the operation of the Seller's Plant in a manner inconsistent with Section 3.2.

(d) Where Buyer requires the Dispatch/Turn-Down as result of a Non-Permitted Distribution/Transmission Constraint, Section 4.8 will apply.

4.10 Electric Service to Seller

If at any time Buyer delivers electrical energy to service Seller's Plant Load, then such electrical energy shall be accounted and paid for separately under the applicable agreement for such electricity energy services and will not be netted off of Delivered Energy for the purposes of determining amounts payable by Buyer in accordance with Section 5.1.

ARTICLE 5
PRICE AND PAYMENT TERMS

5.1 Energy Price

In each billing period, Seller shall pay to Buyer, for each KWh of Delivered Energy, the Energy Price calculated in accordance with Schedule "B".

5.2 No Further Payment

The amount payable by Buyer as specified in Section 5.1 is the full and complete payment and consideration payable by Buyer for Delivered Energy and for Environmental Attributes.

5.3 Statements and Payment

(a) **Statements**

(i) Buyer will, by the 15th day of each month after the Buyer's COD, deliver to Seller a statement for the preceding month. The statement must indicate, among other things:

(A) the amount of, and price payable for, Delivered Energy for that month;

(B) any amount owing by Buyer in respect of a Non-Permitted Distribution/Transmission Constraint pursuant to Section 4.8;

(C) any Final Amounts owing by either Party to the other Party.

Where there has been any Delivered Energy purchased by Buyer in the period prior to Buyer's COD, the first statement following Buyer's COD shall also account for all amounts payable by Buyer to Seller for such period prior to Buyer's COD. The statement must set out in reasonable detail the manner by which the statement and the amounts shown thereon were computed and be accompanied by sufficient data to enable Seller, acting reasonably, to satisfy itself as to the accuracy of the statement.

(ii) Either Party may give notice to the other Party of an error, omission or disputed amount on a statement within 36 months after the statement was first issued together with reasonable detail to support its claim. After expiry of that 36 month period, except in the case of willful misstatement, fraud or concealment, amounts on a previously issued statement will be considered accurate and amounts which were omitted will be considered to be nil, other than amounts disputed in accordance with this Section within the 36 month period, which will be resolved in accordance with this EPA.

(iii) If Seller gives notice to Buyer of an error, omission or disputed amount on a statement as described in Section 5.3(a)(ii), Seller may direct Buyer to promptly produce new statements for the relevant month(s). The new statements will show the undisputed amount and disputed amount each in a separate statement or will otherwise separate the amounts in a single statement in a manner acceptable to Seller, acting reasonably.

(b) **Payment**

(i) Within 30 days after receipt of a statement delivered under Section 5.3(a), and subject to Section 5.5, Buyer will pay to Seller or Seller will pay to Buyer the amount set out in the statement, except to the extent Seller in good faith disputes all or part of the statement by notice to Buyer as described in Section 5.3(a)(ii).

(ii) If Seller disputes any portion of a statement, the applicable Party must pay the undisputed net amount payable by it pursuant to the statement or, if applicable, the new statement of the undisputed amount described in Section 5.3(a)(iii).

(iii) The Parties will endeavor to resolve any error, omission or disputed amount on a statement amount within 30 days of the notice described in Section 5.3(a)(ii).

(iv) Any amount required to be paid in accordance with this EPA, but not paid by either Party when due, will accrue interest at an annual rate equal to the Prime Rate plus 2%, compounded monthly. Any disputed amount that is found to be payable will be deemed to have been due within 30 days after the date of receipt of the statement which included or should have included the disputed amount.

(c) **Payment Calculations**

(i) For the purpose of all payment calculations under this EPA:

(A) all payment calculations will be rounded to the nearest cent; and

(B) Energy will be expressed in KWh rounded to two decimal places.

(ii) For the purpose of all payment calculations under this EPA, where CPI is to apply, if Statistics Canada (or the then recognized statistical branch of the Canadian Government):

(A) computes, at any time after the Effective Date, the CPI on a basis different to that employed at the Effective Date, then the CPI will be converted using the appropriate formula recommended by Statistics Canada (or the then recognized statistical branch of the Canadian Government);

(B) at any time ceases to publish or provide the CPI, then the provisions of Section 2.7 of Schedule "A" will apply;

(C) has not published the CPI for a relevant period at the time Buyer is required to provide Seller with a statement, Seller will prepare the invoice based on the CPI in effect at the time the invoice is issued and when the CPI for the relevant period is published, Buyer will recalculate the invoice amounts in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation; or

(D) recalculates the CPI within 36 months after an invoice affected by that CPI calculation has been issued, then Buyer will recalculate the invoice amounts for the relevant period in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation.

5.4 Taxes

All dollar amounts in this EPA do not include any value added, consumption, commodity or similar taxes, including GST and any successor thereto, which, if applicable, will be added to each statement and paid by Buyer.

5.5 Set-off

If Buyer and Seller each owe the other an amount under this EPA in the same month, then such amounts with respect to each Party will be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount will pay to the other Party the difference between the amounts owed, provided that this Section applies only to any purchase price for Delivered Energy and any Final Amount owing by either Party to the other Party. Except as otherwise expressly provided herein, each Party reserves all rights, counterclaims and other remedies and defenses which such Party has, or may be entitled to, arising from or related to this EPA.

5.6 Change in Law and GRA Cost Recovery

(a) If at any time after the Effective Date:

(i) the costs to Buyer of complying with its obligations under this EPA are, as a result of one or more Changes in Law, increased or decreased (including, for greater certainty, any increase of the obligations or risks of Buyer with respect to the Seller's Plant, but excluding any increase of the obligations or risks of Buyer with respect to the System Upgrades or New Interconnection Facilities); or

(ii) the costs to Buyer of complying with its obligations under this EPA which were of a category or type previously recovered under a General Rate Application are determined under a General Rate Application to no longer be approved for recovery from Buyer's customers in such General Rate Application;

then, to the extent that Buyer would not have incurred such costs except for the Seller's Project and/or the entering into of this EPA, the amount payable by Buyer as specified in Section 5.1 shall be adjusted by the amount necessary to reflect those changed costs which Buyer is unable to recover from Buyer's customers in a General Rate Application.

(b) For each relevant event in Section 5.6(a)(i) or 5.6(a)(ii), Buyer shall provide Seller with a statement setting out such information as is reasonably necessary to demonstrate that such an event has occurred, the reasonableness and necessity of the measures taken by

Buyer in relation to the event, its efforts to mitigate the costs associated with such event including reasonable efforts of Buyer to recover such costs from its customers in a General Rate Application, the nature and extent of any increase or decrease in the amount payable by Seller as specified in Section 5.1, and any such other information as may be reasonably requested by Seller.

(c) If in Seller's view there has been a Change in Law that may decrease Buyer's costs, Seller may request Buyer to demonstrate how such Change in Law has affected its costs under this EPA by providing the applicable information contemplated in Section 5.6(b).

(d) The payments between the Parties shall thereafter be adjusted effective as of the date such event in Section 5.6(a)(i) or 5.6(a)(ii) affects the costs of Buyer hereunder.

(e) If there is any Dispute between the Parties with respect to this Section 5.6, including as to the appropriate increase or decrease in any payments between the Parties under this Agreement, the Dispute shall be resolved in accordance with Article 12.

ARTICLE 6
ENVIRONMENTAL ATTRIBUTES

6.1 Environmental Attributes

Seller hereby transfers, assigns and sets over to Buyer all right, title and interest in and to the Environmental Attributes. Seller will ensure that all Environmental Attributes transferred to Buyer under this EPA are free and clear of all liens, claims, charges and encumbrances. Seller shall use commercially reasonable efforts to (i) provide information reasonably requested by Buyer in relation to such Environmental Attributes, including as may be required to allow Buyer to verify or certify that such Environmental Attributes exist or have been created and (ii) assist in having Seller's Plant certified, licensed, qualified or approved under any rules, regulations, programs or applicable Laws of any Governmental Authority or independent certification agency in respect of Environmental Attributes, provided that Buyer shall pay Seller all costs reasonably incurred by Seller in respect of the same. Any failure by Seller to exercise such commercially reasonable efforts under this Section 6.1 is a "material default" for the purposes of this EPA, and Buyer may terminate this EPA under Section 9.1(j).

ARTICLE 7
EPA ADMINISTRATION, RECORDS AND AUDITS

7.1 Records

Each of Buyer and Seller will prepare and maintain all Records, or duplicates of such Records, at Buyer's head office or local Yukon office or the Seller's Plant, as applicable, or following the expiry of the Term or the earlier termination of this EPA, at such other location as may be agreed in writing between the Parties, for a period of not less than 7 years from the date on which each such Record is created. The Audit Parties may take copies of such Records for the purposes of an inspection or audit under Section 7.2.

7.2 Inspection and Audit Rights

For the sole purpose of verifying:

(a) compliance with this EPA;

(b) the accuracy of statements, supporting information and calculations delivered by a Party under this EPA;

(c) the qualification of the Seller's Plant and the Energy for the Environmental Certification; or

(d) the liability of Seller for System Upgrades Costs and New Interconnection Facilities Costs,

Buyer or Seller, as applicable, will, on reasonable prior written notice from either Party desiring to conduct an audit, provide the Audit Parties with prompt access during normal business hours to (i) in respect of Buyer, Buyer's records solely relating to this EPA, or (ii) in respect of Seller, Seller's Plant and all records relating to the Seller's Plant, including any Seller Confidential Information, as applicable, to enable the Audit Parties to conduct an inspection or audit thereof. The Audit Parties will exercise any access and audit rights under this Section in a manner that minimizes disruption to the operation of the Party subject to the audit. The audit rights contained in this Section 7.2 shall be subject to the limitations set forth in Section 5.3.

7.3 Seller Consents

Seller will promptly provide any consents required to enable any of the Audit Parties to make enquiries with any Governmental Authority or any Person administering the Environmental Certification concerning any or all of the following: (a) the qualification of the Seller's Plant and the Energy for Environmental Certification, the status of the Environmental Certification and copies of any audits, inspections or reports prepared in connection with the Environmental Certification; and (b) compliance by Seller with Laws and Permits applicable to the Seller's Plant.

ARTICLE 8
FIRST NATION CLAIMS

8.1 Notification of First Nation Claim

Given the ownership and location of the Project, Seller and Buyer do not expect any First Nation Claims. However, if Buyer or Seller receives or obtains evidence of a First Nations Claim, it will notify the other Party as soon as practicable.

8.2 Obligation to Consult

If Buyer receives, obtains evidence or becomes aware of a First Nations Claim, it may direct Seller, at Seller's cost, to:

(a) consult with the First Nations making the First Nation Claim, or, if requested by Buyer, assist Buyer in the consultation process;

(b) take any measures Seller deems necessary to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts provided the measures are consented to in advance by Buyer and the First Nations making the First Nation Claim; and

(c) provide regular written reports to Buyer concerning Seller's compliance with this Section, as may be reasonably requested by Buyer.

8.3 Seller Termination for First Nation Claim

At any time prior to Buyer's COD, if:

(a) within 60 days of Buyer receiving, obtaining evidence or becoming aware of a First Nations Claim, Buyer does not make a direction to Seller as contemplated in Section 8.2;

(b) Buyer notifies Seller in writing that it will not make a direction to Seller as contemplated in Section 8.2; or

(c) after consultation with the First Nations making the First Nation Claim it becomes clear that the measure(s) necessary for Seller to resolve the First Nation Claim or to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts would, in Seller's discretion, impose a commercially unreasonable cost on Seller, or would require the consent of Buyer under this EPA or agreement by Buyer to amend this EPA in order to address any Potential Impacts and such consent or agreement to amend is not provided within 60 days after Seller's request to Buyer,

then Seller may terminate this EPA on notice to Buyer. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. A termination by Seller under this Section will, for all purposes of this EPA, be treated in the same manner as a termination by Seller under Section 9.3(c) of this EPA (including the obligations of Seller under Section 9.7). The termination of this EPA is the exclusive remedy to which Seller may be entitled to if Seller elects to terminate this EPA under this Section.

8.4 Buyer Termination for First Nation Claim

At any time prior to Buyer's COD, if Buyer receives, obtains evidence or becomes aware of a First Nations Claim, Buyer may, at its sole discretion, terminate this EPA on notice to Seller. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. Upon a termination by Buyer under this Section 8.4, Seller shall reimburse Buyer for costs or liabilities described in Sections 9.7(a), (b) and (c). The reimbursement by Seller of such costs or liabilities, the indemnification by Seller contemplated in Section 8.5 and the termination of this EPA are the exclusive remedies to which Buyer may be entitled to if Buyer elects to terminate this EPA under this Section.

8.5 Seller Indemnity for First Nation Claim

Seller shall indemnify and hold Buyer and its Affiliates harmless from any and all claims, damages, costs, expenses, or liabilities whatsoever incurred by Buyer and its Affiliates in relation to such First Nation Claim and such indemnity shall survive termination of this EPA.

ARTICLE 9
TERMINATION

9.1 Termination by Buyer

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA by notice to Seller if:

(a) Seller's COD does not occur within 730 days following Target Seller's COD for any reason whatsoever (including Force Majeure), provided that Buyer may terminate this EPA under this provision only if Buyer delivers a termination notice prior to Seller's COD; or

(b) at any time after Buyer's COD, Seller fails to deliver at least an average of 25% of the aggregate Projected Monthly Energy as set out in Schedule "E" to Buyer over all hours in a period of 730 continuous days for any reason whatsoever (including Force Majeure, a Distribution/Transmission Constraint), but excluding a Non-Permitted Distribution/ Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(c) at any time after Buyer's COD, Buyer is unable to accept delivery of Energy at the POI for a period of 730 continuous days due to Force Majeure invoked by Buyer or a Distribution/ Transmission Constraint other than a Non-Permitted Distribution/ Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(d) Seller breaches Section 4.5; or

(e) Seller fails to complete any application, payment, filing, study, document or other step in the process for interconnecting the Seller's Plant to the Distribution System, Transmission System or New Interconnection Facilities, as applicable, in accordance with the requirements of, and within the time limits, including any cure periods, specified by Buyer, and such failure could reasonably be expected to have an adverse impact on Buyer or any third party; or

(f) any System Interconnection Study Report completed after the Effective Date contains information that is inconsistent with the description of the Seller's Plant in Schedule "B" and Seller has not received Buyer's consent under Section 3.3 for the change to Schedule "B"; or

(g) Seller is Bankrupt or Insolvent; or

(h) Seller, as a result of an act or omission of Seller, ceases to be exempt from regulation as a "public utility" as defined in the *Public Utilities Act* with respect to the Seller's Plant and the sale of Energy to Buyer under this EPA, and the loss of such exemption could reasonably be expected to have an adverse effect on the benefit to Buyer of this EPA; or

(i) an amount due and payable by Seller to Buyer under this EPA remains unpaid for 30 days after its due date and such default has not been cured within 30 days after Buyer has given notice of the default to Seller; or

(j) Seller is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Buyer to Seller of the default Seller has cured the default or, if the default cannot be cured within that 30 day period, Seller demonstrates to the reasonable satisfaction of Buyer that Seller is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time. A "material default" includes any purported Assignment of this EPA without the consent of Buyer.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Seller.

9.2 Notice of Termination Event

Seller will notify Buyer promptly if Seller is Bankrupt or Insolvent or if there is a material risk that Seller will become Bankrupt or Insolvent or if Seller has defaulted under any agreement with a Facility Lender or if any Permit or land tenure agreement for the Seller's Plant is terminated or expires.

9.3 Termination by Seller

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Seller may have under this EPA or at law or in equity in respect of any of the following events, Seller may terminate this EPA by notice to Buyer if:

(a) after Buyer's COD, Buyer has not accepted delivery of Energy for a period of 730 continuous days due to an event described in Section 4.4 or any event of Force Majeure and Seller is not entitled to receive any payment pursuant to Section 4.8 in respect of that period; or

(b) the Seller's Plant has suffered major damage where the cost to repair the damage exceeds the net present value (using the Present Value Rate) of the expected revenues under the EPA for the remainder of the Term less the net present value (using the Present Value Rate) of the estimated operating and maintenance costs for the Seller's Plant for the remainder of the Term; or

(c) Seller has been unable to achieve Seller's COD for a period of 730 days after Target Seller's COD or has been unable to deliver Energy to the POI for a period of 730 continuous days after Seller's COD in either case solely as a result of Force Majeure invoked by Seller or a Distribution/Transmission Constraint other than a Non-Permitted Distribution/Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(d) Buyer is Bankrupt or Insolvent; or

(e) except where an amount has been disputed in the manner specified in Section 5.3(a)(ii), an amount due and payable by Buyer to Seller under this EPA remains unpaid for 30 days after its due date and such default has not been cured within 30 days after Seller has given notice of the default to Buyer; or

(f) Buyer is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Seller to Buyer of the default Buyer has cured the default or, if the default cannot be cured within that 30 day period, Buyer demonstrates to the reasonable satisfaction of Seller that Buyer is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Buyer.

9.4 Termination by Buyer for Convenience

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA for convenience upon 90 days prior notice to Seller.

9.5 Effect of Termination

Upon expiry of the Term or earlier termination of this EPA in accordance with its terms:

(a) the Parties may pursue and enforce any rights and remedies permitted by law or equity in respect of any prior breach or breaches of this EPA and may enforce any liabilities and obligations that have accrued under this EPA prior to the expiry of the Term or the date of termination or that are stated to arise on termination of this EPA, subject to any express restrictions on remedies and limitations or exclusions of liability set out in this EPA;

(b) both Parties will remain bound by Section 3.5 with respect to the satisfaction of residual obligations for the period prior to termination or that are specified to arise on, or continue following, termination, and Sections 12.1 and 13.1 associated with Delivered Energy prior to termination of this EPA; and

(c) Seller will remain bound by Sections 7.1 and 7.2 for a period of 36 months following expiry or termination of this EPA;

and, in all such cases, both Parties will remain bound by any other provisions necessary for the interpretation and enforcement of the foregoing provisions.

9.6 Buyer Payment on Termination

If Seller terminates this EPA under any of Sections 9.3(d), 9.3(e) or 9.3(f) or Buyer terminates this EPA for convenience under Section 9.4, Buyer will pay to Seller an amount equal to the applicable Termination Payment due at the time of termination determined in accordance with Schedule "F".

9.7 Seller Payment on Termination

If Buyer terminates this EPA on or before 90 days after Seller's COD or Seller terminates this EPA on or before Buyer's COD under any of Sections 9.3(a), 9.3(b) or 9.3(c), Seller will, within 30 days after receipt of an invoice from Buyer, reimburse Buyer for:

(a) all System Upgrade Costs and New Interconnection Facilities Costs incurred by Buyer, or which Buyer has become contractually obligated to pay, prior to the termination of the EPA including System Upgrade Costs and New Interconnection Facilities Costs Seller would otherwise be responsible for under Section 3.5;

(b) any incremental liability for System Upgrade Costs and New Interconnection Facilities Costs which Buyer will incur as a result of the termination of this EPA; and

(c) any System Upgrade Costs and New Interconnection Facilities Costs which Seller is responsible for under any reimbursement agreement pursuant to Section 3.3.

9.8 Calculation and Payment

Buyer will pay any amount which it owes under Section 9.6 within 30 Business Days after the date of delivery of an invoice by Seller to Buyer. Any amounts owing by Seller to Buyer under this EPA will be netted against any amount owing by Buyer to Seller under Section 9.6.

9.9 Exclusive Remedies

Payment by Buyer of the amount determined under Section 9.6 is the exclusive remedy to which Seller is entitled, and Buyer's limit of liability, for termination of this EPA by Seller pursuant to any of Sections 9.3(d), 9.3(e) or 9.3(f). Subject to Section 9.4 and 9.7, termination of this EPA is the exclusive remedy to which Buyer or Seller, as the case may be, is entitled if Buyer or Seller elects to exercise its right to terminate this EPA under any of Section 9.1, 9.3(a), 9.3(b) or 9.3(c). For greater certainty, subject to Section 9.4 and 9.7, Seller will not be required to pay any termination payment on termination by Buyer of this EPA. Neither Party will have any right to terminate this EPA except as expressly set out herein.

ARTICLE 10
REPRESENTATIONS AND WARRANTIES

10.1 Seller's Representations

Seller represents and warrants to Buyer, and acknowledges that Buyer is relying on those representations and warranties in entering into this EPA, as follows:

(a) Seller is a corporation formed under the laws of _____, is validly existing and is in good standing under the laws of ____, is lawfully authorized to carry on business in _____, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;

(b) this EPA constitutes a valid and binding obligation of Seller enforceable against Seller in accordance with its terms; and

(c) this EPA has been duly authorized, executed and delivered by Seller.

10.2 Buyer's Representations

Buyer represents and warrants to Seller, and acknowledges that Seller is relying on those representations and warranties in entering into this EPA, as follows:

(a) Buyer is a corporation formed under the laws of the Yukon, is validly existing and is in good standing under the laws of the Yukon, is lawfully authorized to carry on business in the Yukon, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;

(b) this EPA constitutes a valid and binding obligation of Buyer enforceable against Buyer in accordance with its terms; and

(c) this EPA has been duly authorized, executed and delivered by Buyer.

ARTICLE 11
LIABILITY LIMITATIONS

11.1 Limit of Liability

Buyer's liability for damages for any failure to take or pay for Delivered Energy under this EPA is limited to the amount payable by Buyer for that Delivered Energy under Article 5, amounts owing under Sections 4.8 and any interest thereon calculated under this EPA.

11.2 Consequential Damages

Neither Party will be liable to the other Party for any special, incidental, exemplary, punitive or consequential damages with respect to, arising out of, relating to or in any way connected with a Party's performance or non-performance under this EPA.

ARTICLE 12
DISPUTES

12.1 Dispute Resolution Procedure

Any dispute, controversy or claim arising out of or relating to this EPA ("**Dispute**") shall be exclusively and finally resolved in accordance with the dispute resolution procedure set forth in this Article 12 (the "**Dispute Resolution Procedure**").

12.2 Commencement of the Dispute Resolution Procedure

The Parties shall make reasonable efforts to first resolve any Dispute. If a Dispute cannot be resolved by the Parties, then either Party may initiate the Dispute Resolution Procedure by giving notice of the Dispute to the other Party (the "**Notice of Dispute**"). The Notice of Dispute shall contain a brief statement of the nature of the Dispute, set out the relief requested, and request that the Dispute Resolution Procedure be commenced.

12.3 Negotiations

Upon the submission of a Notice of Dispute pursuant to Section 12.2, each of the Parties shall refer the Dispute to a designated senior management executive with the authority to negotiate a settlement of the Dispute for that Party (the "**Senior Management Executives**"). The Senior Management Executives of the Parties shall attempt to resolve the Dispute within 30 days from the date on which the Notice of Dispute was issued, or such longer period as the Senior Management Executives may otherwise unanimously agree. If the Senior Management Executives unanimously agree upon a resolution of the Dispute, such resolution shall be memorialized in a written settlement agreement mutually acceptable to the Parties and shall be binding on the Parties.

12.4 Arbitration

If a Dispute is not resolved by Senior Management Executives within 30 days from receipt of a Notice of Dispute (or such longer period as the Senior Management Executives may otherwise agree in writing), the Dispute shall, at the request of either Party, be resolved by binding arbitration under the Rules of Arbitration of the International Chamber of Commerce (the "**ICC Rules**"), except to the extent of conflicts between the ICC Rules and the provisions of this EPA, in which event the provisions of this EPA shall prevail. The following provisions shall apply to an arbitration commenced pursuant to this Section 12.4:

(a) the number of arbitrators shall be one;

(b) the place, or legal seat, of the arbitration shall be Whitehorse, Yukon;

(c) the language to be used in the arbitral proceedings shall be English;

(d) all awards issued by the arbitrator shall be final, non-appealable and binding on the Parties. Any award may be filed in any court of competent jurisdiction and may be enforced by a Party as a final judgment in such court. The Parties expressly waive, to the maximum extent permitted by law, any right of appeal of any award or reference of any matter to any court, other than as may be necessary to recognize or enforce an award;

(e) the arbitrator shall be guided by the International Bar Association's Rules on the Taking of Evidence in International Commercial Arbitration;

(f) the Parties shall request that the arbitrator render its final award within 12 months of the commencement of the arbitration, or as soon as possible thereafter, provided that no award shall be invalid if it is not rendered within the time period herein specified;

(g) any award for monetary damages shall be made and payable in Canadian Dollars and may include interest from the date of any breach or violation of this EPA until paid in full at the rate determined by the arbitrator;

(h) the Parties agree that any arbitration carried out hereunder shall be kept private and confidential, and that the existence of the proceedings and any element of it (including all awards, the identity of the Parties and all witnesses and experts, all materials created for the purposes of the arbitration, all testimony or other oral submissions, and all documents produced by a Party that were not already in the possession of the other Party) shall be kept confidential, except (i) with the consent of the Parties, (ii) to the extent disclosure may be lawfully required in bona fide judicial proceedings relating to the arbitration, (iii) where disclosure is lawfully required by a legal duty, and (iv) where such information is already in the public domain other than as a result of a breach of this clause. The Parties also agree not to use any information disclosed to them during the arbitration for any purpose other than in connection with the arbitration;

(i) where a Dispute relates to the EPA, the Parties shall agree to consolidate the matters in Dispute under such agreements in a single arbitration;

(j) the Parties agree that during the resolution of a Dispute pursuant to this Article 12, the Parties shall continue to perform their obligations under this EPA, provided that such performance shall be without prejudice to the rights and remedies of the Parties and shall not be read or construed as a waiver of a Party's right to claim for recovery of any loss, costs, expenses or damages suffered as a result of the continued performance of this EPA; and

(k) each Party will be responsible for its own costs under this Article 12, subject to the award of an arbitrator.

ARTICLE 13
CONFIDENTIALITY

13.1 Confidentiality

(a) **Additional Confidentiality Obligation -** During the Term and for two years thereafter:

(i) Buyer will treat as confidential, and will not disclose to any third Person, Seller Confidential Information, and

(ii) Seller will treat as confidential, and will not disclose to any third Person, Buyer Confidential Information.

(b) **Disclosure of Confidential Information -** Notwithstanding Section 13.1(a) above:

(i) Seller may also disclose Buyer Confidential Information and Buyer may disclose Seller Confidential information in the following circumstances:

(A) disclosures expressly authorized under this EPA or otherwise set out in this EPA;

(B) disclosures to enable a Party to fulfill its obligations under the EPA;

(C) disclosure in any arbitration or legal proceedings for the enforcement of the EPA;

(D) disclosure to the Party's directors, officers, employees, Facility Lenders, consultants and advisors, and purchasers of the Environmental Attributes, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;

(E) subject to Section 13.1(b)(ii)(D), disclosure required to be made by a Party by an order of a court, a regulatory agency or a tribunal or under any law, regulatory requirements or any requirement of any stock exchange that is binding upon a Party, provided that (i) to the extent reasonably practicable, the Party intending to make such disclosure gives reasonable notice to the other Party before make the disclosure, and (ii) limits the disclosure to that required by the applicable order, Laws or regulatory or stock exchange requirement;

(F) disclosure to a third Person if such information was known by that third Person before disclosure by Buyer or Seller, as the case may be, provided the third Person did not know of the information as a result of a breach of the non-disclosure obligations in this EPA; or

(G) disclosure with the consent of Buyer, in the case of Buyer Confidential Information, or Seller, in the case of Seller Confidential Information.

(ii) Buyer may disclose Seller Confidential Information in the following circumstances:

(A) disclosure to Buyer's Affiliates or to a third Person, and their respective employees, consultants and advisors, for the purpose of reselling or marketing any Energy, including disclosure of Seller Confidential Information by such Affiliate or third Person to those who have purchased or may purchase the Energy;

(B) for purposes other than those described in Section 13.1(b)(i), to Buyer's Affiliates and to any directors, officers, employees, consultants and advisors of any Affiliates, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;

(C) to any ministers, deputy ministers, servants or employees of the Yukon or the federal government, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality; or

(D) disclosure in any regulatory proceeding, whether related to this EPA or not, to the extent that Buyer considers disclosure is necessary or desirable to support its position in such proceeding.

ARTICLE 14
FORCE MAJEURE

14.1 Force Majeure

(a) If there is a Force Majeure affecting a Party's ability to perform an obligation under this EPA, and that Party wishes to declare a Force Majeure, that Party will promptly notify the other Party of the Force Majeure. The notice of Force Majeure must identify the nature of the Force Majeure, the date the Force Majeure commenced, the expected duration of the Force Majeure, and the particular obligations affected by the Force Majeure. If (i) a notice of Force Majeure is provided in accordance with this Section, (ii) the event in question is in fact an event of Force Majeure as defined in this EPA, and (iii) the event of Force Majeure commenced on the commencement date in the notice of Force

Majeure, then the Force Majeure will be deemed to have been invoked as of the commencement date stated in the notice.

(b) Neither Party will be in default of any obligation under this EPA if a Party is unable to perform that obligation due to an event or circumstance of Force Majeure, provided notice is delivered in accordance with this Section and the circumstances are, in fact, an event or circumstance of Force Majeure.

(c) Subject to any limitations expressly set out in this EPA, the time for performance of such obligation will be extended by the number of days that Party is unable to perform such obligation as a result of the event or circumstance of Force Majeure. The Party invoking Force Majeure will make commercially reasonable efforts to promptly remove the Force Majeure and will promptly respond to any inquiry from the other Party regarding the efforts being undertaken to remove the Force Majeure and will give prompt notice of the end of the Force Majeure.

ARTICLE 15
GENERAL PROVISIONS

15.1 Independence

The Parties are independent contractors, and nothing in this EPA or its performance creates a partnership, joint venture or agency relationship between the Parties.

15.2 Enurement

This EPA enures to the benefit of the Parties, their successors and their permitted assigns.

15.3 Assignment

(a) Seller may not assign this EPA except with the prior consent of Buyer, which consent may not be unreasonably withheld, conditioned or delayed provided such Assignment is to a Facility Lender. Any Assignment (other than an Assignment to a Facility Lender) is subject to the assignee entering into and becoming bound by this EPA, assuming all the obligations and liabilities of Seller under this EPA arising both before and after the Assignment, and providing the representations and warranties set out in Section 10.1 effective as at the time of Assignment, and Seller not being in default under this EPA. Unless agreed to in writing by Buyer, Seller shall remain jointly and severally liable with the assignee for all obligations of Seller under this EPA.

(b) Any request by Seller for Buyer's consent under Section 15.3(a) must be delivered to Buyer not less than 30 days before the date of the proposed Assignment. A request under this Section must be accompanied by such information as reasonably required by Buyer to assess the request for consent including the name, address and ownership structure of the assignee, details of any consultation with First Nations that may be impacted by the Seller's Plant or the Assignment with respect to the proposed Assignment, list of the directors and officers of the assignee and information concerning the assignee's operations, experience and financial status.

(c) If Seller seeks consent to Assign this EPA to a Facility Lender, Buyer may require, as a condition of its consent to the Assignment, that Seller and the Facility Lender enter into a

Lender Consent Agreement with Buyer containing customary provisions. If required by a Facility Lender, Buyer will enter into a Lender Consent Agreement with the Facility Lender and Seller containing customary provisions. Seller will reimburse Buyer for all costs reasonably incurred by Buyer in connection with any request by Seller for Buyer's consent pursuant to Section 15.3(a).

15.4 Entire Agreement

This EPA contains the entire agreement between the Parties with respect to the purchase and sale of Energy and supersedes all previous communications, understandings and agreements between the Parties with respect to the subject matter hereof. There are no representations, warranties, terms, conditions, undertakings or collateral agreements express, implied or statutory between the Parties other than as expressly set out in this EPA. **[Note to Developers – as described in the SOP Rules, to the extent that a Project interconnects into AEY's portion of the YIS, there may be additional agreements required between AEY and Seller, in which case this section may need to be modified]**

15.5 Amendment

This EPA may not be amended except by an agreement in writing signed by both Parties.

15.6 No Waiver

Other than in respect of the specific matter or circumstance for which a waiver is given, and except as otherwise specified in this EPA, no failure by a Party to enforce, or require a strict observance and performance of, any of the terms of this EPA will constitute a waiver of those terms or affect or impair those terms or the right of a Party at any time to enforce those terms or to take advantage of any remedy that Party may have in respect of any other matter or circumstance.

15.7 Notices

Any notice, consent, waiver, declaration, request for approval or other request, statement or bill that either Party may be required or may desire to give to the other Party under this EPA must be in writing addressed to the other Party at the address for that Party stated in Schedule "A" and:

(a) notices under Section 14.1, Article 8 and Article 9 must be delivered by hand or by a courier service during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day;

(b) all notices other than notices described in Section 15.7(a) may be delivered by email during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day; and

(c) either Party may change its address for notices under Section 3 of Schedule "A" to this EPA by notice to the other Party.

15.8 Interconnection Notices

Nothing in the System Interconnection Guidelines and no exercise of any right thereunder, restricts or otherwise affects any right, obligation or liability of either Party under this EPA, except to the extent set out expressly herein, and no notice, consent, approval or other communication or decision under or in relation to the System Interconnection Guidelines will constitute or be relied upon as a notice, consent, approval or communication or decision under this EPA.

15.9 Commodity Contract/Forward Contract

The Parties agree and intend that this EPA constitutes an "eligible financial contract" under the *Bankruptcy and Insolvency Act* (Canada) and *Companies' Creditors Arrangement Act* (Canada).

15.10 Further Assurances

Each Party will, upon the reasonable request of the other Party, do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required for the performance of this EPA including, in the case of Seller, completing any registration process required in respect of Environmental Attributes as requested by Buyer.

15.11 Severability

Any provision of this EPA which is illegal or unenforceable will be ineffective to the extent of the illegality or unenforceability without invalidating the remaining provisions of this EPA.

15.12 Counterparts

This EPA may be executed in counterparts, each of which is deemed to be an original document and all of which are deemed one and the same document.

[Signature Page Follows]

IN WITNESS WHEREOF each Party by its duly authorized representative(s) has signed this EPA effective as of the date set out on page one of this EPA.

[SELLER]		**[UTILITY - BUYER]**	
Per:	____________________ [Name] [Title]	Per:	____________________ [Name] [Title]
Per:	____________________ [Name] [Title]	Per:	____________________ [Name] [Title]

SCHEDULE "A"

DEFINITIONS AND INTERPRETATION

1. DEFINITIONS

References in a Schedule to a section or Section mean a section or Section of this EPA, and not a Schedule, unless otherwise stated. The following words and expressions wherever used in this EPA have the following meaning:

1.1 "**Affiliate**" means, with respect to any Party or any third Person, any Person directly or indirectly Controlled by, Controlling, or under common Control with, such Party or the third Person.

1.2 "**Annual Operating Plan**" means a 12-month operating plan for the Seller's Plant that includes for term of each operating plan, (a) a schedule of the expected total deliveries of Energy at the POI in each month and (b) a schedule of any Planned Outages of the Seller's Plant expected by Seller. The Annual Operating Plan will be consistent with Good Industry Practice and shall be substantially in the form attached hereto as Schedule "C", subject to such modifications thereto as may be reasonably required by Buyer.

1.3 "**Application**" means the application and all supporting documents and information with respect to the Seller's Plant filed by Seller with Buyer in the Standing Offer Program.

1.4 "**Assign**" or "**Assignment**" means to assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term and, without limiting the foregoing, each of the following is deemed to be an Assignment of this EPA by Seller:

(a) any sale or other disposition of all or a substantial part of Seller's ownership interest in the Seller's Plant, or of all or any interest of Seller in this EPA or revenue derived from this EPA;

(b) any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant or Seller's ownership interest therein; and

(c) any change of Control, merger, amalgamation or reorganization of Seller.

1.5 "**Audit Parties**" means the applicable Party conducting an audit under this EPA and its Affiliates, representatives, consultants, advisors and any other third Person retained in respect of the applicable audit.

1.6 "**Bankrupt or Insolvent**" means, with respect to a Person:

(a) the Person has started proceedings to be adjudicated a voluntary bankrupt or consented to the filing of a bankruptcy proceeding against it;

(b) the Person has filed a petition or similar proceeding seeking reorganization, arrangement or similar relief under any bankruptcy or insolvency law;

(c) a receiver, liquidator, trustee or assignee in bankruptcy has been appointed for the Person or the Person has consented to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy;

(d) the Person has voluntarily suspended the transaction of its usual business; or

(e) a court of competent jurisdiction has issued an order declaring the Person bankrupt or insolvent.

1.7 "**Business Day**" means any calendar day which is not a Saturday, Sunday or Yukon statutory holiday.

1.8 "**Buyer**" means _____________ and its successors and permitted assigns.

1.9 "**Buyer Confidential Information**" means technical or commercial information disclosed by Buyer to Seller that Buyer directs, and clearly marks, as confidential, including the System Interconnection Guidelines and this EPA but excluding information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Seller, or (ii) is known to Seller before disclosure to it by Buyer, or becomes known to Seller, thereafter by way of disclosure to Seller by any other Person who is not under an obligation of confidentiality with respect thereto.

1.10 "**Buyer's COD**" shall occur when the System Upgrades have been completed and Buyer provides a notice of completion of the same to Seller.

1.11 "**Change in Law**" means (a) the enactment, adoption, promulgation, modification or repeal of any applicable Laws or any change in the interpretation or administration of any applicable Laws resulting from a decision of a Governmental Authority which occurs after the Effective Date; but in each case excluding a Change in Law relating to income tax, or (b) the requirement for a new Permit (including due to a change in the circumstances in which a Permit is required), a change in the terms of any Permit after the date such Permit is granted, or any change in the interpretation or administration of any Permits resulting from a decision of a Governmental Authority.

1.12 "**Condition Date**" means the date specified as such in Schedule "B".

1.13 "**Conditions Precedent**" means those conditions precedent set out in Schedule "B".

1.14 "**Control**" of any Person means:

(a) with respect to any corporation or other Person having voting shares or the equivalent, the ownership or power to vote, directly or indirectly, shares, or the equivalent, representing 50% or more of the power to vote in the election of directors, managers or Persons performing similar functions;

(b) ownership of 50% or more of the equity or beneficial interest in that Person; or

(c) the ability to direct the business and affairs of any Person by acting as a general partner, manager or otherwise.

1.15 "**CPI**" means the "Canada All Items (Not Seasonally Adjusted)" Consumer Price Index as published by Statistics Canada or any successor agency thereto.

1.16 "**Delivered Energy**" means in each month after Buyer's COD the amount of Energy delivered by Seller at the POI in that month as recorded by Buyer's Meter less the applicable Line Losses.

1.17 "**Development Progress Report**" means a report describing the progress of the financing, design, engineering, construction, Interconnection, and commissioning of the Seller's Plant, that is in form and content acceptable to Buyer, acting reasonably.

1.18 "**Discretion**" (whether or not capitalized) means sole, absolute and unfettered discretion unless this EPA expressly states otherwise.

1.19 "**Dispatch/Turn-Down**" means for Seller to turn down or shut off the Seller's Plant.

1.20 "**Dispatch/Turn-Down Deemed Energy**" has the meaning given to such term in Section 4.9(b)(i).

1.21 "**Distribution System**" means the distribution, protection, control and communication facilities in the Yukon that are or may be used in connection with, or that otherwise relate to, the transmission of electrical energy at 35 kilovolts or less, and includes all additions and modifications thereto and repairs or replacements thereof.

1.22 "**Distribution/Transmission Constraint**" means any disconnection of the Seller's Plant from the Distribution System or Transmission System, or any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System preventing or limiting deliveries of Energy at the POI or within the Distribution System or Transmission System or any direction from Buyer to reduce generation of the Seller's Plant as a result of any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System.

1.23 "**Effective Date**" shall mean the date on which all Conditions Precedent have been satisfied or waived in accordance with Section 2.1.

1.24 "**Electrical Grid**" means the electrical grid into which the Seller's Plant will be interconnected, as identified in Schedule "B"**.**

1.25 "**Eligible Clean Energy**" means wind, hydro, geothermal, biomass and solar energy sources permitted under the IPP Policy for the SOP generated by a Project located in Yukon which is directly connected into the YIS or the WLG through the New Interconnection Facilities.

1.26 "**Energy**" means all electrical energy expressed in KWh generated by the Seller's Plant, excluding electrical energy generated by the Seller's Plant which is required to service the Seller's Plant Load.

1.27 "**Energy Price**" has the meaning given to such term in Schedule "B".

1.28 "**Environmental Attributes**" means the following as attributable to Energy delivered to Buyer under this EPA:

(a) all attributes directly associated with, or that may be derived from, the Energy delivered to Buyer under this EPA having decreased environmental impacts relative to certain other generation facilities or technologies including any existing or future credit, allowance, "green" tag, ticket, certificate or other "green" marketing attribute or proprietary or contractual right, whether or not tradeable;

(b) any credit, reduction right, offset, allowance, allocated pollution right, certificate or other unit of any kind whatsoever, whether or not tradeable and any other proprietary or contractual right, whether or not tradeable, resulting from, or otherwise related to the actual or assumed reduction, displacement or offset of emissions at any location other than the Seller's Plant as a result of the generation, purchase or sale of the Energy delivered to Buyer under this EPA;

(c) any credit, reduction right, off-set, allowance, allocated pollution right, certificate or other unit of any kind whatsoever whether or not tradeable resulting from or otherwise related to the reduction, removal, or sequestration of emissions at or from the Seller's Plant; and

(d) all revenues, entitlements, benefits and other proceeds arising from or related to the foregoing, but for certainty not including:

i. benefits or proceeds from environmental incentive programs offered by Governmental Authorities that do not require a transfer of the attributes in (a) to (c) above; and

ii. benefits or proceeds from social programs, including programs relating to northern or rural development, employment or skills training, or First Nations, that do not require a transfer of the attributes in Sections (a) to (c) above.

1.29 "**Environmental Certification**" means any certification Buyer requires Seller to obtain under Section 6.1.

1.30 "**Facility Lender**" means any lender(s) providing any debt financing or debt hedging facilities for the design, engineering, construction and/or operation of the Seller's Plant and any successors or assigns thereto and any Person taking any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant.

1.31 "**Final Amount**" means an amount owing by either Party to the other Party under this EPA, including as a result of a breach of this EPA, where such amount is: (a) undisputed by the Party owing such amount; or (b) has been finally determined by an arbitration award under Section 12.1 of this EPA or by a court order and all rights of appeal in respect of such award or order have been exhausted or have expired.

1.32 "**First Nation Claim**" means a legal claim or proceeding or written threat to commence a legal claim or proceeding from or on behalf of First Nations where such claim or threat alleges a breach or potential breach of, or an impact to: any First Nations’ Treaty rights, rights under a Settlement Agreement (as that term is defined in the Yukon Umbrella Final Agreement), or rights under section 35 of the *Constitution Act*, 1982, by (a) this EPA, (b) the Seller's Plant, (c) the Interconnection or any works related to the Interconnection, or (d) any authorization granted by the Yukon or federal government relating to the Seller's Plant and its operations.

1.33 "**First Nations**" means any one of the 14 First Nations in the Yukon.

1.34 "**Force Majeure**" means any event or circumstance not within the control of the Party, or any of its Affiliates, claiming Force Majeure, but does not include:

(a) any economic hardship or lack of money, credit or markets;

(b) an event or circumstance that is the result of a breach by the Party seeking to invoke Force Majeure of a Permit or of any applicable Laws;

(c) a mechanical breakdown or control system hardware or software failure, unless the Party seeking to invoke Force Majeure can demonstrate by clear and convincing evidence that the breakdown or failure was caused by a latent defect in the design or manufacture of the equipment, hardware or software, which could not reasonably have been identified by normal inspection or testing of the equipment, hardware or software;

(d) an event or circumstance caused by a breach of, or default under, this EPA or a willful or negligent act or omission by the Party seeking to invoke Force Majeure;

(e) any Distribution/Transmission Constraint unless such event is caused by an event or circumstance not within the control of Buyer; or

(f) any acts or omissions of: (i) any Affiliate, employee, director, officer, agent or other representative of the Party invoking Force Majeure; (ii) any vendor, supplier, contractor, subcontractor, consultant or customer of or to the Party invoking Force Majeure; or (iii) any other Person for whom the Party invoking Force Majeure is responsible at law, unless the act or omission is caused by an event or circumstance that would constitute Force Majeure if the Person described above was a party to this EPA in place of a Party invoking Force Majeure.

1.35 "**Forced Outage**" means the immediate removal of one or more generating units of the Seller's Plant or transmission or distribution infrastructure of the Seller's Plant from service in response to equipment alarms or any damage identified during a Planned Outage or Maintenance Outage requiring extension of those Planned Outage or Maintenance Outage.

1.36 "**General Rate Application**" means any application, review, process, or procedure in which the YUB sets and approves rates to be charged by Buyer for the supply of the service for which it is franchised in accordance with the *Public Utilities Act*.

1.37 "**Good Industry Practice**" means:

(a) in respect of Buyer, any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the Yukon; and provided that Buyer shall be in compliance with Good Industry Practice in respect of any equipment comprising the Distribution System or Transmission System, if it operates such equipment in accordance with all applicable original equipment manufacturer guidelines and requirements provided to Buyer by supplier of such equipment; and

(b) in respect of Seller, any of the practices, methods and acts engaged in or approved by a significant portion of the electric generation industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in Western Canada.

1.38 "**Governmental Authority**" means any federal, provincial, local or foreign government or any of their boards or agencies, or any regulatory authority other than Buyer and Seller and entities controlled by Buyer or Seller.

1.39 "**GST**" means the goods and services tax imposed under the *Excise Tax Act* (Canada) as that Act may be amended or replaced from time to time.

1.40 "**Interconnection"** means the POI.

1.41 "**IPP Policy**" has the meaning given to such term in the recitals to this EPA.

1.42 "**Joint Operating Procedure**" means the joint operating procedure attached as Schedule "H" as may be modified by Buyer from time to time. **[Note to Developer - where the Project is located on AEY's portion of the YIS, the EPA will be entered into between Seller and YEC, however the System Interconnection Guidelines and the Joint Operating Procedure will be established under a 3 party agreement among Seller, YEC and AEY]**

1.43 "**KW**" means kilowatt.

1.44 "**KWh**" means kilowatt-hour.

1.45 "**Laws**" means any and all statutes, laws (including common law), ordinances, rules, regulations, codes, orders, bylaws, policies, directions, standards, guidelines, protocols and other lawful requirements of any Governmental Authority in effect from time to time.

1.46 "**Lender Consent Agreement**" means a lender consent agreement in the form and substance acceptable to Buyer, acting reasonably.

1.47 "**Line Losses**" means losses of electricity associated with the transmission and transformation of Energy and other electricity, if applicable, from the Seller's Plant to the POI that are recorded by the Meter or reasonably estimated by Buyer.

1.48 "**Line Loss Methodology**" means the Line Loss Methodology set forth in the System Interconnection Study Report for the purposes of this Project.

1.49 "**Maintenance Outage**" means any outage of Buyer's Distribution System or Transmission System or the Seller's Plant that is not a Planned Outage or a Forced Outage that typically has a flexible start and end time and of shorter duration than a Planned Outage.

1.50 "**Meter**" means a meter owned by Buyer that is: (a) capable of accurately measuring the quantity of Energy generated by the Seller's Plant and delivered to the POI independent of all other generation equipment or facilities, (b) capable of being remotely interrogated; and (b) calibrated to measure on an hourly basis the quantity of Energy delivered by Seller to the POI.

1.51 "**Monthly Energy Shortfall Payment**" has the meaning given to such term in Schedule "E".

1.52 "**New Interconnection Facilities**" means those additions, modifications and upgrades required to interconnect the Project to the Electrical Grid which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any System Upgrades.

1.53 "**New Interconnection Facilities Costs**" means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the New Interconnection Facilities, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.

1.54 "**Non-Permitted Distribution/Transmission Constraint**" has the meaning given to such term in Section 4.8(a).

1.55 "**Outage**" means a Forced Outage, Maintenance Outage, or Planned Outage of Buyer's Distribution System or Transmission System or Seller's Plant.

1.56 "**Outage Notice**" means a notification of any Outage or revised notification of any Outage required to be delivered by Seller to Buyer or Buyer to Seller under this EPA that describes the timing, frequency, nature and duration of the Outage and that is in a format that may be prescribed by Buyer from time to time.

1.57 "**Party**" means Buyer or Seller, and "**Parties**" means both Buyer and Seller.

1.58 "**Permits**" means permits, certificates, licences, approvals and other authorizations issued by any Governmental Authorities as may be required for the design, construction, ownership, operation, maintenance and decommissioning of (i) the Seller's Plant and the delivery of Energy to the POI, and (ii) the System Upgrades and the New Interconnection Facilities.

1.59 "**Person**" means an individual, body corporate, firm, partnership, joint venture, trust, legal representative or other legal entity.

1.60 "**Planned Outage**" means an outage that is scheduled well in advance for purposes of inspections, maintenance, or repair of Buyer's Distribution System or Transmission System or Seller's Plant, that typically has a predetermined duration and scope of work, occurs only once or twice per year, and may last for several days.

1.61 "**POI**" or "**Point of Interconnection**" means the point at which the Seller's Plant interconnects with the Distribution System or Transmission System, as identified on the Single Line Diagram.

1.62 "**Potential Impacts**" means any adverse or potentially adverse impact on the established or potential aboriginal rights (including title) of First Nations as a result of:

(a) this EPA;

(b) the Project;

(c) the interconnection of the Seller's Plant to the Distribution System or Transmission System; or

(d) any activities directly related to the Seller's Plant that enable Seller to comply with its obligations under this EPA that are carried out by Seller, any Affiliate, consultant or contractor of Seller, or any other Person for whom Seller is responsible at law.

1.63 "**PPT**" means Pacific Prevailing Time, which means Pacific Daylight Time or Pacific Standard Time as applicable.

1.64 "**Present Value Rate**" means the annual yield on a Government of Canada bond having a term and maturity date that most closely matches the remaining Term (as at the date of the applicable calculation) and expiry date of this EPA, plus 3%.

1.65 "**Prime Rate**" means the floating prime interest rate announced from time to time by the main branch of Bank of Montreal in Whitehorse, Yukon, or any successor thereto, expressed as an annual rate, as the reference rate it will use to determine rates of interest payable on Canadian dollar commercial loans made in Canada.

1.66 "**Project**" means the financing, design, engineering, procurement, construction, commissioning, operation and maintenance of the Seller's Plant.

1.67 "**Project Cluster**" means two or more existing or proposed Projects under the SOP Rules that Buyer determines in its Discretion are so closely related to each other that they should be considered a project cluster for the purposes of the Standing Offer Program.

1.68 "**Project Energy Volume**" (in KWh) means the maximum annual Energy which Buyer may sell to Seller from the Project in any calendar year as set out in Schedule "B"; provided that where the Term does not commence on January 1, such amount shall be prorated for the first and last contract year which do not reflect a full calendar year. **[Note to Developers – this amount will be set when the EPA is executed. It will be determined based on the annual energy volume which is expected to be generated by the Project in a calendar year determined based on the maximum number of KWh which the applicable Project would generate assuming that it generated in accordance with the Nameplate Capacity after taking into account a reasonable capacity factor for the applicable Eligible Clean Energy type]**

1.69 "**Project Standards**" means:

(a) all applicable Laws;

(b) the terms and conditions of all Permits, including land tenure agreements, issued in connection with the Seller's Plant;

(c) Good Industry Practice;

(d) the description of the Seller's Plant in Schedule "B";

(e) the requirement that Energy must qualify as Eligible Clean Energy; and

(f) the terms and conditions of this EPA (including the System Interconnection Guidelines).

1.70 "**Public Utilities Act**" means the *Public Utilities Act* (Yukon) and any successor or replacement legislation.

1.71 "**Records**" means all records and logs required to properly administer this EPA, including:

(a) Energy generation records and operating logs;

(b) Meter readings;

(c) maintenance reports;

(d) invoice support records;

(e) documents concerning compliance with Project Standards, but excluding any such documents that are protected by solicitor-client privilege;

(f) records related to System Upgrade Costs and New Interconnection Facilities Costs;

(g) all information reasonably required to establish the amount of Energy Seller could have sold during a Distribution/Transmission Constraint including logs of all Outages of the Seller's Plant and other reductions in Energy output (specifying the date, time, duration and reasons for each such outage and each reduction in Energy output); and

(h) information relating to the Environmental Certification, information relating to the existence, nature and quality of Environmental Attributes, information required for the purposes of any Environmental Attributes or energy certification or tracking system, and any other information Buyer requires to enable it or any of its Affiliates to obtain and realize the benefit of the Environmental Attributes,

all consistent with Good Industry Practice.

1.72 "**Regulatory Agency Authorizations**" means the issuance of those Permits which are specified as required for the Project in the YESAB assessment report recommendation to proceed issued in respect of the Project.

1.73 "**Seller**" means the Party so identified on page one of this EPA, and its successors and permitted assigns.

1.74 "**Seller Confidential Information**" means any of Seller's confidential technical or financial information provided by Seller to Buyer in confidence with express written notice to Buyer of the confidential nature of the information, but excluding:

(a) this EPA; and

(b) information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Buyer, or (ii) is known to Buyer before disclosure to it by Seller, or becomes known to Buyer thereafter by way of disclosure to Buyer by any other Person who is not under an obligation of confidentiality with respect thereto.

1.75 "**Seller's COD**" means the commercial operation date of Seller's Plant which is the date on which all of the following conditions have been satisfied in respect of the Seller's Plant:

(a) Seller has obtained all Permits required for the construction, commissioning, and operation of the Seller's Plant and all such Permits are in full force and effect;

(b) the Seller's Plant has been fully constructed in accordance with the Project Standards;

(c) Seller is not: (A) Bankrupt or Insolvent; (B) in default of any payment obligation or requirement to post security under this EPA; (C) in material default of any of its other covenants, representations, warranties or obligations under this EPA; or (D) in material default under any Permit or Law applicable to the construction, commissioning or operation of the Seller's Plant or under any land tenure agreement for the site on which the Seller's Plant is located;

(d) a Meter has been installed at the POI in accordance with Section 3.6 of this EPA;

(e) Seller has delivered to Buyer a written notice together with certificate of Seller's professional registered engineer confirming that Seller's COD has been achieved; and

(f) Buyer has delivered a Commission Notice to Operate, or such other document(s) of similar effect as may be substituted therefor, which evidences no material deficiencies, in respect of the Seller's Plant Capacity and Seller's Plant operations;

and for purposes of this EPA, Seller's COD will be deemed to have occurred at 24:00 PPT on the later of the dates set out above.

1.76 "**Seller's Plant**" means Seller's plant described in Schedule "B" and all assets required to interconnect that plant to the Distribution System or Transmission System; all rights, property, facilities, assets, equipment, materials, Permits and contracts required to design, engineer, procure, construct, commission, operate and maintain the plant described in Schedule "B" and to interconnect that plant to the Distribution System or Transmission System, whether real or personal and whether tangible or intangible including all land tenure and all books, Records and accounts with respect to the Seller's Plant described in Schedule "B"; and shall include replacement parts or equipment which are of the same or similar nature as the parts or equipment being replaced and which do not materially increase the amount of Energy available from Seller's Plant.

1.77 "**Seller's Plant Capacity**" means the electrical generating capacity of the Seller's Plant set out in Schedule "B".

1.78 "**Seller's Plant Load**" means any electrical energy consumed by Seller's Plant.

1.79 "**Single Line Diagram**" means the simplified electrical representations of the Seller's Plant, the Interconnection, the Distribution System and Transmission System attached hereto in Schedule "B".

1.80 "**SOP OIC**" means that Order in Council issued by the Government of Yukon on January 24, 2019 regarding, among other things, the Standing Offer Program.

1.81 "**SOP Rules**" means the Standing Offer Program Rules developed by the Government of Yukon which governed this EPA as at the date of this EPA.

1.82 "**Standing Offer Program**" or "**SOP**" means the Standing Offer Program as described in the IPP Policy.

1.83 "**System Interconnection Guidelines**" means those system interconnection guidelines in the form attached as Schedule "G" hereto, as amended or replaced by Buyer from time to time. **[Note to Developer - where the Project is located on AEY's portion of the YIS, the EPA will be entered into between Seller and YEC, however the System Interconnection Guidelines and the Joint Operating Procedure will be established under a 3 party agreement among Seller, YEC and AEY]**

1.84 "**System Interconnection Study Report**" means the detailed interconnection study issued to Seller by Buyer which, among other things, (i) evaluates the impact of the Project on the reliability of Buyer's system, (ii) provides a planning-level estimate of the required System Upgrades and New Interconnection Facilities and associated costs, and (iii) establishes the Line Loss Methodology for this Project, a copy of which is attached as Schedule "D".

1.85 "**System Upgrades**" means additions, modifications and upgrades to the Distribution System, Transmission System or any portion of Buyer's generation system that are determined by Buyer to be required in order to facilitate the interconnection and to allow such Distribution System, Transmission System or any portion of Buyer's generation system to support the integration of the Energy produced by the Seller's Plant in accordance with this EPA and the System Interconnection Guidelines, which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any New Interconnection Facilities.

1.86 "**System Upgrade Costs**" means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the System Upgrades, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.

1.87 "**Target Buyer's COD**" means the target date for achieving Buyer's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.

1.88 "**Target Seller's COD**" means the target date for achieving Seller's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.

1.89 "**Term**" has the meaning given to such term in Section 2.1.

1.90 "**Termination Payment**" has the meaning given to such term in Schedule "F".

1.91 "**Transmission System**" means the transmission, substation, protection, control and communication facilities owned and operated by Buyer, and includes all additions and modifications to those facilities and repairs or replacements of those facilities.

1.92 "**Upgrade Costs Advance**" has the meaning given to such term in Section 3.5(a).

1.93 "**Upgrade Costs Security**" has the meaning given to such term in Section 3.5(a).

1.94 "**Utilities**" means both Yukon Energy Corporation or Yukon Electrical Company, doing business as ATCO Electric Yukon, as applicable.

1.95 "**YESAA**" means the *Yukon Environmental and Socio-economic Assessment Act*, SC 2003, c 7.

1.96 "**YESAB**" means the Yukon Environmental and Socio-economic Assessment Board.

1.97 "**YUB**" means the Yukon Utilities Board and any successor thereto appointed from time to time under the *Public Utilities Act*.

2. INTERPRETATION

2.1 **Headings -** The division of this EPA into Articles, sections, Sections, paragraphs and Schedules and the insertion of headings are for convenience of reference only and do not affect the interpretation of this EPA.

2.2 **Plurality and Gender -** Words in the singular include the plural and vice versa. Words importing gender include the masculine, feminine and neuter genders.

2.3 **Governing Law -** This EPA is made under, and will be interpreted in accordance with, the Laws of the Yukon. Subject to Section 12.1, any suit, action or proceeding (a "**Proceeding**") arising out of or relating to this EPA may be brought in the courts of the Yukon at Whitehorse, and those courts have non-exclusive jurisdiction in respect of any Proceeding and the Parties hereby irrevocably attorn to the jurisdiction of such courts in respect of any Proceeding.

2.4 **Industry Terms -** Technical or industry specific phrases or words not otherwise defined in this EPA have the well-known meaning given to those terms as of the date of this EPA in the industry or trade in which they are applied or used.

2.5 **Statutory References -** Reference to a statute means, unless otherwise stated, the statute and regulations, if any, under that statute, in force from time to time, and any statute or regulation passed and in force which has the effect of supplementing or superseding that statute or those regulations.

2.6 **Currency -** References to dollars or $ means Canadian dollars, unless otherwise stated.

2.7 **Reference Indices -** If any index, tariff or price quotation referred to in this EPA ceases to be published, or if the basis therefor is changed materially, there will be substituted an available replacement index, tariff or price quotation that most nearly, of those then publicly available, approximates the intent and purpose of the index, tariff or quotation that has so ceased or changed. This EPA will be amended as necessary to accommodate such replacement index, tariff or price quotation, all as determined by written agreement between the Parties, or failing agreement, by arbitration under Section 12.1 of this EPA.

2.8 **Conversions -** If a value used in a calculation in this EPA must be converted to another unit of measurement for purposes of consistency or to achieve a meaningful answer, the value will be converted to that different unit for purposes of the calculation.

2.9 **Additional Interpretive Rules -** For the purposes of this EPA, except as otherwise expressly stated:

(a) "this EPA" means this EPA as it may from time to time be supplemented or amended and in effect, and includes the Schedules attached to this EPA;

(b) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this EPA as a whole and not to any particular section, Section or other subdivision;

(c) the word "including" or "includes" is not limiting whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto;

(d) the words "year" and "month" refer to a calendar year and a calendar month;

(e) any consent, approval or waiver contemplated by this EPA must be in writing and signed by the Party against whom its enforcement is sought, and may be given, withheld or conditioned in the unfettered discretion of the Party of whom it is requested, unless otherwise expressly stated;

(f) all rights and remedies of either Party under this EPA are cumulative and not exclusive of any other remedies to which either Party may be lawfully entitled, and either Party may pursue any and all of its remedies concurrently, consecutively and alternatively; and

(g) any notice required to be given, or other thing required to be done, under this EPA on or before a day that is not a Business Day, will be deemed to be given or done when required hereunder if given or done on or before the next following Business Day.

3. ADDRESSES FOR NOTICES

3.1 Notices to Buyer - Except as noted below, all notices addressed to Buyer will be delivered to the following address:

To: [BUYER]
____
Whitehorse, YT
______
Attention: Attention: Manager
Email: _________

3.2 Notices to Seller - All notices addressed to Seller will be delivered to the following address:

To: [SELLER]
____
Whitehorse, YT
______
Attention: Attention: Manager
Email: _________

SCHEDULE "B"

PROJECT DESCRIPTION

CONTRACT PARTICULARS:

1. **Condition Date:**

   [Insert the date on which the Conditions Precedent must be satisfied by Seller]

2. **Conditions Precedent:**

   The Conditions Precedent are as follows:

   (a) *[Seller shall have received all of the Permits described below in form and substance acceptable to Seller and Buyer, acting reasonably:*

   (i) *[Regulatory Agency Authorizations]*

   (ii) *[Other]*

   (b) *[provision of security under Section 3.5 for System Upgrade Costs and New Interconnection Facilities Costs]; and*

   (c) *[others Conditions Precedent]*.

3. **Term:**

   The "**Term**" of this EPA commences on the Effective Date and continues for a period of __ years following Buyer's COD.

   [Note to Developers: Developers may elect a single term under an EPA of <u>up to</u> the following number of years for the applicable Eligible Clean Energy:

Eligible Clean Energy	**Term Limit**
Wind	**25 years**
Hydro	**40 years**
Geothermal	**40 years**
Biomass	**20 years**
Solar	**25 years]**

4. **Energy Price and Seasonal Adjustment:**

   (a) In each billing period, Seller shall pay to Buyer, for each KWh of Delivered Energy the "**Energy Price**" calculated as follows:

   [Note to Developers: For Projects connected to the YIS, the Energy Price will be calculated as follows. The first and third blanks above will be completed with the applicable Base Fuel Price as described in Section 4.2 of the SOP Rules. The blank in the subscript will be completed with the year in which the EPA is signed.

Energy Price$_n$ = (.5 * $__/KWh * CPI$_{January\ 1,\ n}$ / CPI$_{January\ 1,\ __}$) + (.5 * $__/KWh)]

[Note to Developers: For Projects connected to the WLG, the Energy Price will be calculated as follows. The first blank above will be completed with the applicable Base Fuel Price as described in Section 4.2 of the SOP Rules. The blank in the subscript will be completed with the year in which the EPA is signed.

Energy Price$_n$ = ($__/KWh * CPI$_{January\ 1,\ n}$ / CPI$_{January\ 1,\ __}$)]

Where:

n = the year for which the relevant calculation is being conducted

CPI $_{January\ 1,\ n}$ = the CPI for December in the year immediately prior to the year for which the relevant calculation is being conducted;

(b) For each hour, the Energy Price determined above for Delivered Energy during that hour will be adjusted to an amount (expressed in $/KWh) equal to the percentage of that Energy Price applicable for that hour as set out in the table in Schedule "I".

SELLER'S PLANT

1. **Location of Control Building:**

[Insert nearest latitude and longitude]

2. **Eligible Clean Energy Type:**

[Describe Eligible Clean Energy utilized]

3. **Seller's Plant Capacity:**

[Insert Project Nameplate Capacity]

4. **Project Energy Volume:**

[Insert Project Energy Volume in KWh in any year, being the annual energy volume which is expected to be generated by the Project determined based on the maximum number of KWh which the applicable Project would generate assuming that it generated in accordance with the Seller's Plant Capacity after taking into account a reasonable capacity factor for the applicable Eligible Clean Energy type]

5. **Seller's Plant Description:**

[Insert Project description]

Please refer to Seller's single line diagram in Exhibit B-1.

Total AC Power:
Primary AC line voltage:
Total AC line current:

Total DC power:
Open-circuit DC voltage:
Operating DC voltage:
Total DC operating current:

6. **Target Seller's COD:**

[Insert]

7. **Electrical Grid:**

[Insert Yukon Integrated System (YIS) or Watson Lake Grid (WLG)].

BUYER'S SYSTEM UPGRADES

[Note to Developers – These System Upgrades will be more fully scoped in the System Interconnection Study Report]

1. **System Upgrades:**

[Description to come]

Please refer to Buyer's single line diagram in Exhibit B-2.

2. **New Interconnection Facilities:**

[Description to come]

Please refer to Buyer's single line diagram in Exhibit B-2.

3. **Target Buyer's COD:**

[To come]

BREAKERS/SWITCHES AND SYNCHRONIZATION

[Note to Developers – To be developed for each Project]

EXHIBIT B-1

Seller's Single Line Diagram

[Note to Developers – To be developed for each Project]

EXHIBIT B-2

Buyer's Single Line Diagram

[Note to Developers – To be developed for each Project]

SCHEDULE "C"

FORM OF ANNUAL OPERATING PLAN

DATE: _______, 20__.

TO: _________ ("Buyer")

RE: Electricity Purchase Agreement between _________ ("Seller") and Buyer dated the ___ day of _____, 20__ (the "EPA")

The following sets out the Annual Operating Plan of Seller for the 12 months commencing on January 1, 20__ (the "**Applicable Period**").

(a) The following (from Table E-1 of Schedule "E" of the EPA) is the schedule of the expected total deliveries of Energy at the POI in each month of the Applicable Period:

	Projected Hourly Energy (KWh/h) **(A)**	**Projected Monthly Energy (KWh)** **(B)**
January		
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		

(b) The following is the schedule of any Planned Outages of the Seller's Plant expected by Seller for the Applicable Period:

[to come]

(c) The following is the schedule of operations and maintenance activities planned for the Seller's Plant expected by Seller for the Applicable Period:

[to come]

Dated effective as of the date set forth above.

[SELLER]

Per: ________________________________
[Name]
[Title]

Per: ________________________________
[Name]
[Title]

SCHEDULE "D"

SYSTEM INTERCONNECTION STUDY REPORT

SCHEDULE "E"

MONTHLY ENERGY SHORTFALL PAYMENT

Monthly Energy Shortfall Payments

In any calendar month in which there has occurred a Non-Permitted Distribution/Transmission Constraint then Buyer shall pay Seller Monthly Energy Shortfall Payment,

where:

"**Monthly Energy Shortfall Payment**" means the Monthly Constraint Shortfall multiplied by the price which is payable for Delivered Energy under Section 5.1 of the EPA; and

"**Monthly Constraint Shortfall**" (expressed in KWh) means, for each calendar month, means the aggregate of the duration of each Non-Permitted Distribution/Transmission Constraint (measured as a fraction determined as the aggregate number of minutes in such Non-Permitted Distribution/Transmission Constraint divided by 60) multiplied by the "Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy" set out in Table E-1 below for the applicable calendar month.

Table E-1

	Projected Hourly Energy (KWh/h) (A)	**Projected Monthly Energy (KWh) (B)**	**Non-Permitted Distribution/Transmission Constraint Factor (F1)**	**Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy (KWh/h) (A x F1)**
January			_%	
February			_%	
March			_%	
April			_%	
May			__%	
June			__%	
July			__%	
August			__%	
September			__%	
October			__%	
November			__%	
December			__%	

<u>Revisions to Projected Hourly Energy and Projected Monthly Energy</u>

Within 90 days following the end of the 2nd year after Buyer's COD, the Parties shall review and revise the values in Table E-1 above for Projected Hourly Energy and Projected Monthly Energy to reflect the average actual amount of Delivered Energy sold to Buyer in the 2 years following Buyer's COD for the applicable months.

SCHEDULE "F"

TERMINATION PAYMENT

The "**Termination Payment**" at any time shall be equal to (a) the Gross Termination Payment set out below for the Contract Year in which the termination occurred, less (b) the actual amounts paid or owing by Buyer to Seller for Delivered Energy for the Contract Year in which the termination occurred.

Table F-1

Termination Year	Gross Termination Payment
Year 1	
Year 2	
Year 3	
Year 4	
Year 5	
Year 6	
Year 7	
Year 8	
Year 9	
Year 10	
Year 11	
Year 12	
Year 13	
Year 14	
Year 15	
Year 16	
Year 17	
Year 18	
Year 19	
Year 20	
Year 21	
Year 22	
Year 23	
Year 24	
Year 25	

SCHEDULE "G"

SYSTEM INTERCONNECTION GUIDELINES

SCHEDULE "H"

JOINT OPERATING PROCEDURE

SCHEDULE "I"

DELIVERY TIME ADJUSTMENT TABLE

Seasonal Adjustment is subject to change.

Month	**Seasonal Adjustment**
January	100%
February	100%
March	100%
April	100%
May	100%
June	100%
July	100%
August	100%
September	100%
October	100%
November	100%
December	100%

STANDARD FORM ELECTRICITY PURCHASE AGREEMENT

LARGE PROJECTS

F2006 OPEN CALL FOR POWER

Notes to Bidders:

1. *The base form of EPA applies to Projects with a Plant Capacity of 10 MW and larger with the following characteristics:*
    - *Monthly Firm Energy Profile*
    - *Full output sold to BC Hydro*
    - *Seller retains Green Attributes*
    - *Seller retains all GHG obligations*
    - *Project is a BC Clean Electricity Project*
    - *Project has a direct interconnection to the Transmission System*
    - *Seller is a corporation rather than a joint venture or limited partnership.*
2. *The terms and conditions applicable to other types of generating facilities or ownership structures are set out in the Appendices to this EPA. The applicable provisions of Appendix 10, other than Part E, will be incorporated into the relevant sections of the Awarded EPA based on the information in the Seller's Tender. Part E will remain in Appendix 10.*
3. *All blanks in this Standard Form EPA will be completed based on information contained in the Seller's Tender.*
4. *The Awarded EPA will include the Project name on the title page and at the bottom of each page.*

TABLE OF CONTENTS

Page No.

BC HYDRO

STANDARD FORM ELECTRICITY PURCHASE AGREEMENT

LARGE PROJECTS

THIS ELECTRICITY PURCHASE AGREEMENT ("**EPA**") is made as of •, 2006 (the "**Effective Date**")

BETWEEN:

__________________ a corporation incorporated under the laws of ______________ with its head office at _____________________________
____

("**Seller**")

AND:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a corporation continued under the *Hydro and Power Authority Act*, R.S.B.C. 1996, c. 212, with its head office at 333 Dunsmuir Street, Vancouver, BC V6B 5R3.

("**Buyer**")

WHEREAS:

A. The Buyer issued a Call for Tenders on 8 December 2005 for the sale of electrical energy to the Buyer from independent power producers' generation plants in British Columbia with a capacity greater than .05 MW.

B. A Tender in respect of the Project was submitted in response to the CFT not later than _______________, 2006.

C. The Seller desires to sell to the Buyer, and the Buyer desires to purchase from the Seller, Energy from the Seller's Plant on the terms, conditions and exceptions set forth in this EPA.

1. INTERPRETATION

1.1 Definitions - Appendix 1 sets out or references the definitions applicable to certain words and expressions used in this EPA.

1.2 Appendices - Attached to and forming part of this EPA are the following Appendices:

Appendix 1	-	Definitions
Appendix 2	-	Energy Profile
Appendix 3	-	Energy Price
Appendix 4	-	COD Certificate

Appendix 5	-	Seller's Plant Description
Appendix 6	-	Sample Form Standby Letter of Credit
Appendix 7	-	Sample Form Lender Consent Agreement
Appendix 8	-	Sample Form Development Progress Report
Appendix 9	-	Addresses for Delivery of Notices
Appendix 10	-	Special Terms and Conditions

1.3 Headings - The division of this EPA into Articles, sections, subsections, paragraphs and Appendices and the insertion of headings are for convenience of reference only and do not affect the interpretation of this EPA.

1.4 Plurality and Gender - Words in the singular include the plural and vice versa. Words importing gender include the masculine, feminine and neuter genders.

1.5 Governing Law - This EPA is made under, and will be interpreted in accordance with, the laws of the Province of British Columbia. Subject to section 20.7, any suit, action or proceeding (a "**Proceeding**") arising out of or relating to this EPA may be brought in the courts of the Province of British Columbia at Vancouver, and those courts have non-exclusive jurisdiction in respect of any Proceeding and the Parties hereby irrevocably attorn to the jurisdiction of such courts in respect of any Proceeding.

1.6 Industry Terms - Technical or industry specific phrases or words not otherwise defined in this EPA have the well known meaning given to those terms as of the date of this EPA in the industry or trade in which they are applied or used.

1.7 Statutory References - Reference to a statute means, unless otherwise stated, the statute and regulations, if any, under that statute, in force from time to time, and any statute or regulation passed and in force which has the effect of supplementing or superseding that statute or those regulations.

1.8 Currency - References to dollars or $ means Canadian dollars, unless otherwise stated.

1.9 Reference Indices - If any index, tariff or price quotation referred to in this EPA ceases to be published, or if the basis therefor is changed materially, there will be substituted an available replacement index, tariff or price quotation that most nearly, of those then publicly available, approximates the intent and purpose of the index, tariff or quotation that has so ceased or changed. This EPA shall be amended as necessary to accommodate such replacement index, tariff or price quotation, all as determined by written agreement between the Parties, or failing agreement, by arbitration under section 20.7.

1.10 Conversions - If a value used in a calculation in this EPA must be converted to another unit of measurement for purposes of consistency or to achieve a meaningful answer, the value will be converted to that different unit for purposes of the calculation.

1.11 Additional Interpretive Rules - For the purposes of this EPA, except as otherwise expressly stated:

(a) "this EPA" means this EPA as it may from time to time be supplemented or amended and in effect, and includes the Appendices attached to this EPA;

(b) the words “herein”, “hereof” and “hereunder” and other words of similar import refer to this EPA as a whole and not to any particular section, subsection or other subdivision;

(c) the word “including” or “includes” is not limiting whether or not non-limiting language (such as “without limitation” or “but not limited to” or words of similar import) is used with reference thereto;

(d) unless otherwise expressly stated in this EPA, the words “year” and “month” refer to a calendar year and a calendar month;

(e) any consent, approval or waiver contemplated by this EPA must be in writing and signed by the Party against whom its enforcement is sought, and may be given, withheld or conditioned in the unfettered discretion of the Party of whom it is requested, unless otherwise expressly stated;

(f) unless otherwise expressly stated in this EPA, all rights and remedies of either Party under this EPA are cumulative and not exclusive of any other remedies to which either Party may be lawfully entitled, and either Party may pursue any and all of its remedies concurrently, consecutively and alternatively;

(g) the provisions of Appendix 10, if any, govern over the other provisions of this EPA, and all provisions of this EPA are mutually explanatory of one another; and

(h) any notice required to be given, or other thing required to be done, under this EPA on or before a day that is not a Business Day, shall be deemed to be given or done when required hereunder if given or done on or before the next following Business Day.

2. TERM

2.1 Term - The term (“**Term**”) of this EPA commences on the Effective Date and continues until the _TO#2____ anniversary of COD, subject to extension for the period specified pursuant to section 10.2, unless it is terminated earlier as authorized under this EPA.

3. REGULATORY REVIEW

3.1 Regulatory Review Termination - Either Party may terminate this EPA if, within 120 days after the Effective Date, the BCUC has not accepted the EPA for filing as an energy supply contract under section 71 of the UCA on terms and conditions that do not materially alter the price or any other material term or condition of the EPA (“**BCUC Acceptance**”).

3.2 Regulatory Filing - The Buyer, on behalf of itself and the Seller, shall file the EPA with the BCUC within a reasonable time after the Effective Date.

3.3 EPA Support - The Buyer shall take all steps reasonably required to secure the BCUC Acceptance and the Seller shall provide any assistance reasonably requested by the Buyer to secure the BCUC Acceptance. The Parties will not take, and will cause their Affiliates not to take, any action inconsistent with the performance by the Parties of their obligations under this section 3.3. If a Party fails to comply with this section (the “**Breaching Party**”) and, as a result, the EPA is terminated under section 3.1, the Breaching Party shall pay the non-Breaching Party, by not later than 5 Business Days after the date of termination, an amount equal to \$60,000/MW multiplied by the Plant Capacity. The Breaching Party's liability for a breach of this section 3.3 is limited to the amount set out in this section.

3.4 Termination - A Party entitled to terminate under section 3.1 must do so by giving notice to terminate to the other Party at any time after the right to terminate arises pursuant to section 3.1 and prior to the earlier of:

(a) the date of issuance of the BCUC Acceptance; and

(b) the date that is 150 days after the Effective Date.

3.5 Effect of Termination - If this EPA is terminated by either Party in accordance with sections 3.l and 3.4, the following provisions shall apply:

(a) on or before the 30th day following the date of termination, or if that day is not a Business Day, then on or before the next succeeding Business Day, the Buyer shall return the Performance Security to the Seller after deducting any amount to which the Buyer is entitled but which has not been paid pursuant to section 3.3 of this EPA; and

(b) except as set out in section 15.3, the Parties shall have no further liabilities or obligations under, or in relation to, this EPA.

4. DEVELOPMENT

4.1 Development and Construction of the Seller's Plant - The Seller shall, at its expense, perform, or cause to be performed, all Project activities necessary to complete the construction and commissioning of the Seller's Plant and achieve COD in accordance with the terms and conditions of this EPA. The Seller shall commence such Project activities by the date that is the later of: (a) 30 days after the BCUC Acceptance; or (b) if a right to terminate arises under section 3.1, 30 days after that right to terminate has expired, and shall thereafter diligently and continuously carry out such Project activities.

4.2 Modification to Plant Capacity - The Seller shall construct the Seller's Plant with a capacity that does not exceed the Plant Capacity. Except as set out in this section and notwithstanding section 6.2, the Seller shall not increase or decrease the Plant Capacity without the Buyer's prior consent. The Seller may at any time prior to the Guaranteed COD give notice to the Buyer that the Seller intends to increase or decrease the Plant Capacity by an amount not exceeding 10% of the Plant Capacity specified in Appendix 5, provided that:

(a) the Seller has completed all studies required by the Transmission Authority in connection with the proposed increase or decrease in Plant Capacity, such studies include an estimate of any increase in Network Upgrade Costs resulting from the proposed increase or decrease in the Plant Capacity, and the Seller provides copies of such studies to the Buyer together with the notice to the Buyer;

(b) the Seller shall be responsible for, and shall pay, all costs associated with the increase or decrease in the Plant Capacity, including all additional Direct Assignment Costs and Network Upgrade Costs in accordance with section 4.5;

(c) prior to the earlier of:

(i) 30 days after the date of delivery of a notice to the Buyer under this section, and

(ii) the date on which any additional Network Upgrade Costs associated with the increase or decrease in Plant Capacity are incurred,

the Seller shall deliver to the Buyer replacement Performance Security calculated in the manner set out in Appendix 1 to reflect any proposed increase or decrease in the Plant Capacity and an amount equal to the total estimated increase in Network Upgrade Costs resulting from the proposed increase or decrease in the Plant Capacity. Upon receipt of the replacement Performance Security in the required form, the Buyer shall release the existing Performance Security to the Seller, without deduction, other than prior deductions, if any, properly made hereunder;

(d) the Seller shall complete all construction and commissioning associated with the increase or decrease in the Plant Capacity prior to COD;

(e) the Guaranteed COD will not be extended by any increase or decrease in the Plant Capacity; and

(f) the Seller may give only one notice under this section.

Upon delivery by the Seller of a notice under this section and compliance by the Seller with subsections (a) and (c) above, the Buyer and the Seller shall execute an amendment to this EPA to amend Appendix 5 to reflect the proposed increase or decrease in the Plant Capacity as set out in the Seller's notice. The Buyer is not required to accept or pay for any Energy associated with an increase in the Plant Capacity that does not comply with this section and section 7.5 applies to such Energy.

4.3 Permits - The Seller shall promptly obtain, comply with and maintain in full force and effect all Permits. The Seller shall on request promptly provide to the Buyer copies of all Material Permits.

4.4 Development Reports - On each January 1, April 1, July 1 and October 1 after the Effective Date, (or, where such day is not a Business Day, on the first Business Day thereafter) and continuing until COD, the Seller shall deliver to the Buyer a report in the form specified in Appendix 8, describing the progress of the Project.

4.5 Project Changes - The Seller shall not make any change to the point of interconnection with the Transmission System (including any change to the point of interconnection specified in the F2006 CFT Preliminary Interconnection Study Report) without the prior consent of the Buyer, such consent not to be unreasonably withheld, provided that the Seller acknowledges that the Buyer is entitled to require as a condition of the Buyer's consent that the Seller enter into an amendment to this EPA as required to put the Buyer in the position it would have been in under this EPA had the Seller not made a change to the point of interconnection, including with respect to the amount of Eligible Energy. If the Seller makes any change to the point of interconnection between the Seller's Plant and the Transmission System as set out in the F2006 CFT Preliminary Interconnection Study Report or any other change to the information relied on by the Transmission Authority in completing the F2006 CFT Preliminary Interconnection Study Report and developing the Network Upgrade Cost estimate for purposes of the CFT, the Seller shall be liable for all costs related directly or indirectly to such change and for all other losses, costs and damages suffered or incurred by the Buyer, whether as a transmission customer or otherwise, as a result of such change and the Seller shall pay any such amount within 30 days after receiving an invoice from the Buyer for such amount.

5. COMMERCIAL OPERATION DATE

5.1 Guaranteed COD - The Seller shall ensure that the Seller's Plant achieves COD by the Guaranteed COD plus Force Majeure Days.

5.2 Requirements for COD - Subject to sections 5.5 and 5.6, the Seller's Plant will have achieved COD at the commencement of the hour immediately following the hour in which all of the following conditions have been satisfied:

(a) the Seller has obtained all Material Permits and all such Material Permits are in full force and effect;

(b) the Seller's Plant has generated Energy over any continuous 72 hour period, in compliance with all Material Permits, and delivered such Energy to the POI in an amount not less than the greater of:

(i) 90% of the applicable Monthly Firm Energy Delivery Rate multiplied by 72; and

(ii) 20% of the Plant Capacity multiplied by 1 hour multiplied by 72;

(c) the Seller is not: (i) Bankrupt or Insolvent; (ii) in material default of any of its covenants, representations, warranties or obligations under this EPA (other than those defaults in respect of which the Seller has paid all LDs owing under this EPA); or (iii) in material default under any Material Permit, any tenure agreement for the site on which the Seller's Plant is located, the Interconnection Agreement or the Facilities Agreement; and

(d) the Seller has delivered to the Buyer:

(i) a Declaration of Compatibility-Generator (Operating), or such other document(s) of similar effect as may be substituted therefor, issued by the Transmission Authority to the Seller under the Interconnection Agreement;

(ii) data from the Metering Equipment sufficient to demonstrate compliance by the Seller with subsection 5.2(b);

(iii) payment of any amounts owing by the Seller to the Buyer under any of sections 4.2, 4.5 and 5.7; and

(iv) proof of registration by the Seller with Measurements Canada as an energy seller with respect to the Seller's Plant,

provided that, except as hereinafter provided, within 30 days after the last of the requirements set out above is satisfied the Seller delivers to the Buyer: (I) a COD Certificate; (II) the Long Term Operating Plan; and (III) the Annual Operating Plan for the period from COD to December 31 next following COD or if COD occurs after September 30, for the period from COD to December 31 in the year following COD. If the COD Certificate, Long Term Operating Plan and Annual Operating Plan are not delivered by that date, COD will occur at 12:00 PPT on the day of delivery to the Buyer of the last of the foregoing documents. For greater certainty, the Parties acknowledge that, notwithstanding satisfaction of all the conditions set out in subparagraphs (a) to (d) above, the Seller may defer delivery of the documents described in (I), (II) and (III) above until, and the COD will not occur earlier than, the date determined under section 5.5.

5.3 Buyer Right to Observe - The Seller shall provide not less than 10 days' prior notice to the Buyer of the commencement of any proposed testing under subsection 5.2(b) and the Buyer may attend and observe each test under that subsection. If the Seller has given notice to the Buyer in accordance with this section, the Seller shall not be required to give a notice to the Buyer of any further tests which are commenced within 72 hours of the prior test under subsection 5.2(b). The Seller shall provide a new notice in accordance with this section 5.3 in respect of any test that commences more than 72 hours after the end of an unsuccessful test under subsection 5.2(b).

5.4 COD Disputes - The Buyer may, by notice to the Seller within 10 Business Days after the date of delivery to the Buyer of a COD Certificate, contest the COD Certificate on the grounds that the Seller has not satisfied the requirements for COD in section 5.2. Pending the final resolution of any dispute relating to whether the requirements for COD have been satisfied, the Seller shall not be required to remit any COD Delay LDs, provided that upon final determination of the matter, if the determination is made that COD has not been achieved, the Seller shall forthwith remit COD Delay LDs in accordance with section 12.1 calculated from the Guaranteed COD plus Force Majeure Days, together with applicable interest in accordance with subsection 9.2(b). If the Buyer does not deliver a notice to the Seller contesting the COD Certificate within the time specified in this section, COD will be deemed to have occurred as provided in section 5.2.

5.5 Early COD - Except with the Buyer's prior consent, COD may not occur earlier than the later of: (a) 1 October 2007; and (b) 365 days prior to the Guaranteed COD. The Buyer shall not be required to incur any incremental expense (other than payment for Eligible Energy) to enable COD to occur prior to the Guaranteed COD.

5.6 Deemed COD - If on or after the Guaranteed COD, the Seller's Plant has satisfied all requirements for COD, other than those requirements that depend on completion of Network Upgrades, and if the Seller cannot achieve COD solely as a result of a delay in completion of Network Upgrades and such delay is solely caused by the Buyer, then COD will be deemed to have occurred on or after the Guaranteed COD at the commencement of the hour following the hour in which all other conditions for COD were satisfied. The Buyer shall thereafter be liable to pay the Seller for that portion of the Monthly Firm Energy Amount that could have been generated and delivered at the POI but for the delay in completion of the Network Upgrades described above, and all such Energy will be considered Eligible Energy for purposes of this EPA. The portion of the Monthly Firm Energy Amount that could have been generated and delivered at the POI will be determined based on the information described in section 7.9. Except for the payments for deemed Eligible Energy provided for pursuant to this section, the Seller shall have no other rights or remedies against the Buyer, and the Buyer shall have no other liability, with respect to any delay in completion of the Network Upgrades. If the Seller's Plant fails to satisfy the requirements specified in section 5.2 within a reasonable period, but not later than 60 days after completion of the Network Upgrades, the Seller will be deemed not to have achieved COD and the Seller shall within 10 days after receipt of an invoice from the Buyer, refund to the Buyer all payments made by the Buyer to the Seller prior to that date. This section 5.6 will not apply if a delay in completion of any Network Upgrades is due, in whole or in part, to any increase or decrease in Plant Capacity from the Plant Capacity specified in Appendix 5 or to any increase in any Monthly Firm Energy Amount pursuant to section 7.2 or to any change described in section 4.5.

5.7 Early Network Upgrades - If the Seller requires Network Upgrades to be completed prior to 90 days prior to the Guaranteed COD to enable early COD or to enable sales of Pre-COD Energy to third parties, the Seller shall give notice of such requirement to the Buyer and following delivery of such notice, the Seller and the Buyer shall discuss such requirement with the Transmission Authority to determine the incremental costs, if any, required to complete the Network Upgrades prior to 90 days prior to the Guaranteed COD. The Seller shall be responsible for and shall indemnify the Buyer from and against all such incremental costs and expenses and, prior to commencement by the Transmission Authority of any work required to advance the completion date for the Network Upgrades, shall provide to the Buyer replacement Performance Security which includes an amount equal to the total estimated increase in Network Upgrade Costs resulting from any request by the Seller to complete the Network Upgrades prior to 90 days prior to the Guaranteed COD.

6. OPERATION OF SELLER'S PLANT

6.1 Owner and Operator - The Seller shall own the Seller's Plant and shall ensure that the Seller's Plant is operated using qualified and experienced individuals.

6.2 Modifications to Seller's Plant/Additional Generators

(a) **Modifications to Seller's Plant -** The Seller shall not make, without the Buyer's prior consent, any modification or addition, or series of modifications or additions, to the Seller's Plant, except for those modifications or additions which: (i) are not likely to have an adverse effect on the Seller's ability to observe and perform its obligations under this EPA, including the Seller's obligations under subsection 6.3(f); or (ii) are required to comply with a change in Law or a change in Permit conditions (where such change in Permit conditions is initiated by a Governmental Authority) after the Effective Date. The Seller shall provide prior notice to the Buyer of any modifications or additions, or series of modifications or additions, to the Seller's Plant together with an explanation of the reason for such modifications or additions.

(b) **Additional Generators -** The Seller shall not add any additional generators on the site of the Seller's Plant or that otherwise inject output at the same POI as the Seller's Plant, unless the Seller has first entered into an amendment to this EPA with the Buyer as required to address any adverse impacts on the Buyer or on the benefit to the Buyer of this EPA resulting from the construction or operation of such additional generators.

6.3 Standard of Construction and Operation - The Seller shall cause the Seller's Plant to be designed, engineered, constructed, interconnected to the Transmission System, commissioned, operated and maintained in compliance with: (a) all applicable Laws; (b) the terms and conditions of all Permits and land tenure agreements issued in connection with the Seller's Plant; (c) Good Utility Practice; (d) the specifications in Appendix 5, as changed from time to time with the prior consent of the Buyer, provided that, subject to section 6.2, the Seller may amend the information in sections 4 and 5 of Appendix 5 at any time without consent on notice to the Buyer not less than 30 days prior to such change and the Buyer and the Seller will enter into an amendment to this EPA to amend Appendix 5 in accordance with such notice; (e) the Code of Conduct Guidelines Applicable to BC Hydro Contracts in effect as of the date specified for submission of Tenders under the CFT; (f) if applicable, the information provided to the British Columbia Minister of Energy, Mines and Petroleum Resources or to TerraChoice Environmental Marketing to obtain confirmation that the output from the Seller's Plant could be considered BC Clean Electricity in the CFT process; and (g) the terms and conditions of this EPA, the Interconnection Agreement and the Facilities Agreement. Without limiting the foregoing, all equipment installed in the Seller's Plant shall conform to the codes, standards and rules applicable to power plants in British Columbia and the Seller shall ensure that the Seller's Plant is designed, engineered and constructed to operate in accordance with the requirements of this EPA for the full Term of this EPA. Without limiting section 7.3 but subject to subsection 7.8(a), when the Seller is delivering Energy to the Buyer, the Seller shall make commercially reasonable efforts to operate the Seller's Plant in a manner that ensures delivery of Energy at the POI at a uniform rate within each hour.

6.4 Planned Outages - The Seller shall: (a) ensure that no Planned Outage occurs during the Peak Demand Months without the Buyer's prior consent, such consent not to be unreasonably withheld, delayed or conditioned; (b) give the Buyer not less than 90 days' prior notice of any Planned Outage and such notice shall state the start date and hour and the end date and hour for the Planned Outage; (c) make commercially reasonable efforts to coordinate all Planned Outages with the Buyer's requirements as notified to the Seller; and (d) make best efforts to coordinate Planned Outages with the Transmission Authority's maintenance schedule where such schedule is publicly available or otherwise notified to the Seller. Within 45 days after the date of receipt of the Annual Operating Plan or within 14 days after receipt of any adjustment to the Annual Operating Plan pursuant to subsection 6.6(b), the Buyer may request the Seller to reschedule any Planned Outage. Within 14 days after receipt of such a request, the Seller shall provide the Buyer with an estimate, together with reasonable supporting detail, of the costs the Seller expects to incur, acting reasonably, as a result of rescheduling the Planned Outage in accordance with the Buyer's request. Within 7 days after receipt of such cost estimate, the Buyer shall notify the Seller if the Buyer requires the Seller to reschedule the Planned Outage and upon receipt of such notice from the Buyer, the Seller shall adjust the schedule for the Planned Outage as required by the Buyer, provided that the rescheduling is consistent with Good Utility Practice and does not have a materially adverse effect on the operation of the Seller's Plant or on any facility that is a thermal host for the Seller's Plant. The Buyer shall reimburse the Seller for all costs reasonably incurred by the Seller as a result of such rescheduling, but not exceeding the estimate delivered by the Seller to the Buyer under this section. For payment and all other purposes of this EPA, all Planned Outages will be deemed to start at the beginning of an hour and to end at the end of an hour.

6.5 Records - During the Term the Seller shall prepare and maintain all records required to properly administer this EPA, including Energy generation records and operating logs, a log book of all Outages and other reductions in Energy output (specifying the date, time, duration and reasons for each Outage and each reduction in Energy output), meter readings, maintenance reports, invoice support records, documents concerning compliance with Permits and applicable Laws, and all other records and logs consistent with Good Utility Practice. The Seller shall maintain such records or duplicates of such records at the Seller's Plant, or following the expiry of the Term or the earlier termination of this EPA, at such other location as may be agreed to by the Buyer, acting reasonably, for a period of not less than 7 years from the date on which each such record is created.

6.6 Reports to the Buyer - The Seller shall deliver the following documents, reports, plans and notices to the Buyer:

(a) **Long Term Operating Plan -** By the date specified in section 5.2, the Seller shall provide to the Buyer an operating plan for the Seller's Plant for a 10 year period commencing at COD and ending on December 31 of the year in which the tenth anniversary of COD occurs, including the long term major maintenance schedule. On or before September 30 in each year during the Term after the year in which COD occurs, the Seller shall provide the Buyer with an updated plan for the 10 year period commencing on the next succeeding January 1 or to the end of the Term, whichever is less. The Seller shall promptly provide the Buyer with copies of any amendments or modifications to the Long Term Operating Plan. The Long Term Operating Plan shall be consistent with Good Utility Practice and is intended to assist the Buyer in planning activities and is not a guarantee of the timing of Planned Outages;

(b) **Annual Operating Plan -** On or before September 30 in each year during the Term, the Seller shall provide to the Buyer an operating plan for the Seller's Plant for the 12 month period commencing on the next succeeding January 1 which plan may be included in the Long Term Operating Plan. The plan shall include a schedule of Planned Outages for that 12 month period which shall comply with the provisions of section 6.4 and be consistent with Good Utility Practice. The Seller may, on not less than 90 days prior notice to the Buyer, amend the Annual Operating Plan, subject to the provisions of section 6.4;

(c) **Notice of Outages -** Other than for a Planned Outage for which notice has been given pursuant to section 6.4, the Seller shall promptly notify the Buyer of any Outage, or any anticipated Outage, of the Seller's Plant. Any notice under this subsection shall include a statement of the cause of the Outage, the proposed corrective action and the Seller's estimate of the expected duration of the Outage. The Seller shall, except with the Buyer's consent, such consent not to be unreasonably withheld, use best efforts to promptly remove or mitigate any Forced Outage. The Seller shall deliver to the Buyer concurrently with delivery of the statement described in subsection 9.1(a), a report of all Outages during the month for which the statement described in subsection 9.1(a) is issued, including a statement of the cause of each Outage;

(d) **Interconnection Agreement and Facilities Agreement Defaults -** The Seller shall give promptly to the Buyer a copy of any notice of a breach of, or default under, the Interconnection Agreement or the Facilities Agreement, whether given or received by the Seller;

(e) **Notice of Buyer Termination Event -** The Seller shall notify the Buyer promptly of any Buyer Termination Event or any material risk that a Buyer Termination Event will occur or any default by the Seller under any agreement with a Facility Lender; and

(f) **Energy Schedules -** After COD the Seller shall either (as elected by the Seller in a notice delivered to the Buyer prior to COD):

(i) on each Thursday by 12:00 PPT, deliver to the Buyer a schedule of the expected deliveries of Eligible Energy in each day during the next succeeding week commencing at 00:00 PPT on Monday; or

(ii) by 12:00 PPT on each day deliver to the Buyer a schedule of expected deliveries of Eligible Energy for the next succeeding 24 hour period commencing at 00:00 PPT,

provided that such schedules are provided for planning purposes only and do not constitute a guarantee by the Seller that Energy will be delivered in accordance with the schedules and do not limit the amount of Energy the Seller may deliver during the periods covered by the schedules. The Seller shall deliver a revised schedule to the Buyer forthwith upon becoming aware of any expected material change in a filed Energy schedule. The Seller may change its election with respect to the delivery of Energy schedules in accordance with subsection (i) or (ii) above at any time on 60 days' prior notice to the Buyer.

6.7 Exemption from Utility Regulation - The Seller shall not take any action that would cause the Seller to cease to be exempt, or omit to take any action necessary for the Seller to continue to be exempt, from regulation as a “public utility”, as defined in the UCA, with respect to the Seller’s Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA where such designation as a “public utility” could reasonably be expected to have an adverse effect on the Buyer or its interests under this EPA.

6.8 Compliance with Emissions Requirements

(a) **GHG Requirements -** Without limiting section 4.3 or section 6.3, the Seller shall comply with all applicable Laws and all Permits regulating GHG emissions from the Seller’s Plant. The Seller shall by each January 31 after COD (or, if alternate reporting dates are established under any Laws or Permits regulating GHG emissions from the Seller’s Plant, then by such alternate reporting dates) deliver to the Buyer a report signed by a senior officer of the Seller, in a form satisfactory to the Buyer acting reasonably, detailing the status of compliance by the Seller with this section during the immediately preceding year (or if an alternate compliance period is established under any Laws or Permits regulating GHG emissions from the Seller’s Plant, then the report shall address such alternate compliance period). If the Seller is not in compliance with any Law or Permit regulating GHG emissions from the Seller’s Plant and the Seller fails to remedy such non-compliance within 30 days after the date of notice from the Buyer to the Seller, the Buyer may, but is not required to, on behalf of the Seller, purchase any Compliance Units required to remedy, in whole or in part, the Seller’s non-compliance with the applicable Law or Permit. The Seller shall cooperate with the Buyer as necessary to enable the Buyer to purchase such Compliance Units. The Seller shall reimburse the Buyer for all costs (including all commissions, charges, brokerage, consulting and legal fees, taxes, duties, transfer and registration fees and all other transaction costs and expenses) incurred by the Buyer in purchasing such Compliance Units, together with an administration fee equal to 15% of such costs within 30 days after receipt of an invoice from the Buyer for such amount.

(b) **Other Emissions -** Without limiting subsection (a), the Seller is solely responsible at the Seller’s cost for compliance with all applicable Laws and Permits regulating all emissions from the Seller’s Plant, including GHG emissions. The Buyer has no responsibility or liability of any kind whatsoever with respect to any such emissions.

6.9 Disclosure of Information by Transmission Authority - The Seller consents to the Transmission Authority disclosing to the Buyer on request:

(a) all information with respect to Network Upgrades, including any information provided by the Seller to the Transmission Authority that relates to, or affects, Network Upgrades including any preliminary interconnection application, study and report, and any subsequent applications, studies and reports, that contain information relevant to Network Upgrades;

(b) all metering data collected by, or provided to, the Transmission Authority with respect to the Seller’s Plant;

(c) copies of any notice of a breach of, or default under, the Interconnection Agreement or the Facilities Agreement given or received by the Transmission Authority; and

(d) any other information provided by the Seller to the Transmission Authority or by the Transmission Authority to the Seller that is relevant to the administration of this EPA.

The Seller shall promptly on request by the Buyer provide to the Buyer written confirmation of the foregoing consents for delivery by the Buyer to the Transmission Authority.

6.10 Islanding - Subject to the provisions of this section, at any time after the Effective Date and prior to completion by the Seller of the final engineering design for the Seller's Plant, the Seller shall, at the request of the Buyer, provide all information and cooperation required to enable the Buyer to undertake, at the Buyer's cost, any studies the Buyer considers necessary to determine the ability of the Seller's Plant to provide Planned Islanding Capability and the estimated cost of providing, operating and maintaining such Planned Islanding Capability. The Seller shall provide the Buyer with not less than 120 days prior notice of the anticipated date of completion of the final engineering design for the Seller's Plant and the Buyer shall advise the Seller within 60 days after receipt of such notice if the Buyer intends to undertake any studies pursuant to this section. The Buyer shall, within 30 days after receipt of an invoice together with reasonable supporting information, reimburse the Seller for all reasonable costs incurred by the Seller, that the Seller would not otherwise have incurred, to provide the Buyer with information required for any studies pursuant to this section. The Buyer may on notice to the Seller within 30 days after receipt of all studies commissioned by the Buyer under this section advise the Seller that the Buyer wishes to enter into negotiations with the Seller with respect to the Seller's Plant providing Planned Islanding Capability, including any amendments required to this EPA as a result thereof. Upon receipt of such notice the Parties shall negotiate in good faith to determine the terms and conditions on which the Seller will provide such Planned Islanding Capability.

6.11 BC Clean Electricity - If in the CFT process the output from the Seller's Plant was treated as BC Clean Electricity based on a letter from TerraChoice Environmental Marketing confirming eligibility of the Seller's Plant for EcoLogo^{M} Certification, and if the Seller does not obtain EcoLogo^{M} Certification by the date that is one year after COD, the Seller shall within 60 days after the first anniversary of COD, provide a letter to the Buyer from the British Columbia Minister of Energy, Mines and Petroleum Resources confirming that the output from the Seller's Plant is BC Clean Electricity together with a copy of all information provided to the Minister to obtain such confirmation. Without limiting section 6.5, the Seller shall maintain, and shall within 10 Business Days after a request from the Buyer, provide to the Buyer all information the Buyer requires to verify qualification of the output from the Seller's Plant as BC Clean Electricity. The Buyer may at any time during the Term conduct or have a third Person with the necessary expertise conduct, at the Buyer's expense, an audit of the Project Assets, its employees and relevant documentation to verify qualification of the output from the Seller's Plant as BC Clean Electricity. The Seller shall promptly provide to the Buyer any consents required to enable the Buyer to make enquiries with any Governmental Authorities concerning the qualification of the output from the Seller's Plant as BC Clean Electricity. The Seller consents to the disclosure by the Buyer to any Person or any Governmental Authority of any Confidential Information with respect to the Seller's Plant that the Buyer is required to disclose to verify qualification of the output of the Seller's Plant as BC Clean Electricity or to provide confirmation to any such Person or Governmental Authority that the output from the Seller's Plant qualifies as BC Clean Electricity.

7. PURCHASE AND SALE OBLIGATIONS

7.1 Pre-COD Energy - The Buyer shall make commercially reasonable efforts to accept delivery at the POI of all Pre-COD Energy, provided that the Buyer shall not be required to take any steps or to incur any incremental expense to enable the delivery of Pre-COD Energy to the POI prior to 90 days before the Guaranteed COD. Prior to the earlier of COD and the Guaranteed COD the Seller may, on prior notice to the Buyer, sell any Energy to any Person other than the Buyer, and in that case such Energy shall not be delivered, or be deemed to be delivered, to the Buyer.

7.2 Modification to Monthly Firm Energy Amount - The Seller may at any time prior to the first anniversary of COD, give notice to the Buyer that the Seller elects to increase or decrease the Monthly Firm Energy Amount for one or more months, to take effect on the first day of the month immediately following the giving of such notice, provided that the net change in the annual total of the Monthly Firm Energy Amounts resulting from such increase or decrease in the Monthly Firm Energy Amounts does not exceed 10%. Upon receipt of such notice, the Buyer and the Seller shall execute an amendment to this EPA to amend Appendix 2 in accordance with the Seller's notice, provided that:

(a) any such increase or decrease in the Monthly Firm Energy Amounts does not result in the total of the Monthly Firm Energy Amounts for the period from April to July, inclusive, exceeding one-third of the annual total of the Monthly Firm Energy Amounts;

(b) any such increase or decrease in the Monthly Firm Energy Amounts does not result in the Monthly Firm Energy Amount for any month exceeding the Plant Capacity multiplied by the number of hours in the applicable month;

(c) the provisions of subsections 4.2(a) and (b) apply to any such increase or decrease in the Monthly Firm Energy Amounts, *mutatis mutandis*; and

(d) the Seller may give only one notice under this section.

7.3 Post-COD Sale of Energy - Subject to subsection 7.8(a), in each month during the Term after COD, the Seller shall sell and deliver to the Buyer at the POI the Monthly Firm Energy Amount for the applicable month, provided that if COD occurs on any day other than the first day of the month, the Monthly Firm Energy Amount for the month in which COD occurs and for the last month of the Term will be reduced to reflect in the former case, the number of days in the month after COD, and in the latter case, the number of days prior to the expiry of the Term.

7.4 Post-COD Purchase of Energy - Subject to subsection 7.8(b), in each month during the Term after COD, the Buyer shall purchase, and accept delivery from the Seller at the POI of, all Eligible Energy.

7.5 Exclusivity - The Seller shall not at any time during the Term commit, sell or deliver any Energy to any Person, other than the Buyer under this EPA, except for:

(a) Pre-COD Energy sold to third parties in accordance with section 7.1;

(b) during any period in which the Buyer is in breach of its obligations under section 7.4; and

(c) during any period in which the Buyer is not accepting deliveries of Energy from the Seller due to Force Majeure invoked by the Buyer.

7.6 Custody, Control and Risk of Energy - Custody, control, risk of, and title to all Pre-COD Energy delivered to the Buyer and all Eligible Energy passes from the Seller to the Buyer at the POI. The Seller shall ensure that all Energy delivered to the Buyer under this EPA is free and clear of all liens, claims, charges and encumbrances. The Seller shall be responsible for all transmission losses and costs, if any, relating to the transmission of Energy from the Seller's Plant to the POI.

7.7 Price and Payment Obligation - The Buyer shall pay for all Test Energy in respect of which the Seller has not given a notice under section 7.1 and all Eligible Energy in accordance with Appendix 3.

7.8 Limitations on Delivery and Acceptance Obligations

(a) **Limitations on Delivery Obligations -** The obligations of the Seller under section 7.3 are subject to:

(i) Force Majeure invoked by the Seller in accordance with Article 11;

(ii) any Outage, suspension, constraint or curtailment in the operation of the Transmission System preventing or limiting physical deliveries of Eligible Energy at the POI for reasons that are not attributable to the Seller or the Seller's Plant;

(iii) disconnection of the Seller's Plant from the Transmission System by the Transmission Authority for reasons that are not attributable to the Seller or the Seller's Plant;

(iv) the right of the Seller to suspend its performance under this EPA in accordance with Article 14; and

(v) Authorized Planned Outages.

(b) **Limitations on Acceptance Obligations -** The obligations of the Buyer under sections 7.1 and 7.4 are subject to:

(i) Force Majeure invoked by the Buyer in accordance with Article 11;

(ii) disconnection of the Seller's Plant from the Transmission System for reasons not attributable to the Buyer;

(iii) any Outage, suspension, constraint or curtailment in the operation of the Transmission System preventing or limiting physical deliveries of Eligible Energy at the POI for reasons not attributable to the Buyer; and

(iv) the right of the Buyer to suspend the Seller's performance under the EPA in accordance with Article 14.

7.9 Deemed Deliveries - If in any month after COD the Seller is unable to deliver Energy at the POI at any time during that month solely as a result of:

(a) any disconnection of the Seller's Plant from the Transmission System or any Outage, suspension, constraint or curtailment in the operation of the Transmission System preventing or limiting physical deliveries of Eligible Energy at the POI where:

(i) the Transmission Authority is authorized to disconnect the Seller's Plant or suspend firm transmission service under the Interconnection Agreement, Facilities Agreement, any tariff applicable to firm transmission or interconnection service or any other legally enforceable right; and

(ii) such disconnections, Outages, suspensions, constraints or curtailments exceed in the aggregate 24 hours, whether or not continuous, in that month,

but excluding any disconnection, Outage, suspension, constraint or curtailment attributable to the Seller or the Seller's Plant; or

(b) a breach by the Buyer of its obligations under section 7.4,

then, notwithstanding that the Buyer is excused under subsection 7.8(b) from its obligations under section 7.4, in the case of an event described in subsection 7.9(a), all or that portion of the applicable Monthly Firm Energy Amount that could have been generated and delivered at the POI in each hour after the 24 hours has elapsed, but for the occurrence of the event described in subsection 7.9(a) will be deemed to be Eligible Energy, and in the case of an event described in subsection 7.9(b), the amount of Energy, not exceeding the Plant Capacity, that could have been generated and delivered at the POI but for the occurrence of the event described in subsection 7.9(b) will be deemed to be Eligible Energy. The amount of Energy that could have been generated and delivered at the POI during an event described in subsection 7.9(a) or (b) will be determined based on the Seller's Energy schedule for the applicable period, meter readings with respect to the Energy Source, if applicable, readings of the Metering Equipment before and after the occurrence of the event described in subsection 7.9(a) or (b) and other available information. There will be no deemed Eligible Energy during any period specified as a Planned Outage in a notice delivered by the Seller under section 6.4. For greater certainty, the provisions of this section 7.9 will not apply during any period when either Party is excused, in accordance with Article 11, from its obligation to deliver, or to accept delivery of, Energy as a result of a Force Majeure.

7.10 Green Attributes - The Buyer acknowledges that the Seller retains title and all right, benefit and interest in, to and arising from the Green Attributes.

8. METERING

8.1 Installation of Metering Equipment - The Seller shall, at its cost, ensure that revenue metering equipment (the "**Metering Equipment**") is installed, operated and maintained in accordance with the requirements of the Transmission Authority and the requirements of this section. The Seller shall ensure that the Seller's Plant is equipped with electronic meters and SCADA capability. The Metering Equipment shall be installed at a location approved by the Buyer, acting reasonably, which location shall be such that the Metering Equipment can measure the Energy generated by the Seller's Plant independent of all other generation equipment or facilities. The Seller shall ensure that the Metering Equipment is: (a) capable of being remotely interrogated; (b) sufficient to accurately meter the quantity of Energy to be purchased and sold hereunder; (c) calibrated to measure the quantity of Energy delivered to the POI, after adjusting for any line losses from the Seller's Plant to the POI; and (d) in compliance with all requirements set out in the *Electricity and Gas Inspection Act* (Canada) and associated regulations.

8.2 Operation of Metering Equipment - The Metering Equipment shall be used for purposes of calculating the amount of Eligible Energy. In the event of any failure of the Metering Equipment, the Parties shall, until such time as the Metering Equipment has been repaired or replaced, rely upon information provided by any back-up meter installed pursuant to section 8.3, or, in the absence of such back-up meter, the Seller's metering equipment, if any, for purposes of calculating payments due under this EPA. If there is any dispute regarding the accuracy of the Metering Equipment, either Party may give notice to the other Party of the dispute, in which case the Buyer and the Seller will proceed to rectify the matter in accordance with the *Electricity and Gas Inspection Act* (Canada). The Seller shall allow the Buyer to access the Seller's Plant at any time during normal business hours on reasonable advance notice for purposes of inspecting the Metering Equipment. The Seller shall, on the Buyer's request, cause the Metering Equipment to be inspected, tested and adjusted provided that, except as set out below, the Buyer shall not make such a request more than once in each year during the Term. The Seller shall give the Buyer reasonable prior notice of all inspections, tests and calibrations of the Metering Equipment and shall permit a representative of the Buyer to witness and verify such inspections, tests and calibration. If either Party has reason to believe that the Metering Equipment is inaccurate, the Seller shall cause the Metering Equipment to be tested forthwith upon becoming aware of the potential inaccuracy. The Seller shall provide the Buyer with copies of all meter calibration test results and all other results of any test of the Metering Equipment. If any test of the Metering Equipment discloses an inaccuracy outside the inaccuracies permitted under the *Electricity and Gas Inspection Act* (Canada), any payments or adjustments made or calculated under this EPA that would have been affected by the inaccuracy shall be recalculated to correct for the inaccuracy. For purposes of such correction, if the inaccuracy is traceable to a specific event or occurrence at a reasonably ascertainable time, then the adjustment shall extend back to that time; otherwise, it shall be assumed that the error has existed for a period equal to one half of the time elapsed since COD or one half of the time since the last meter test, whichever is more recent, but in any event shall not extend back more than 36 months. Any amounts which are determined to be payable or subject to refund as a result of such re-computations shall be paid to the Party entitled to such amounts within 20 days after the paying Party is notified of the re-computation.

8.3 Duplicate Metering Equipment - The Buyer may at any time during the Term at the Buyer's sole cost, on not less than 30 days prior notice to the Seller, install a duplicate revenue meter at the Seller's Plant at a location to be agreed upon by the Buyer and the Seller, acting reasonably, and the Seller shall allow the Buyer to access the Seller's Plant for such purpose and for the purpose of inspecting and maintaining such equipment. The Seller shall make transformers, transformer connections and telephone access available to the Buyer, as required, if the Buyer elects to install a duplicate revenue meter. Any duplicate revenue meter and metering equipment installed by the Buyer will remain the property of the Buyer, and the Seller shall not tamper with, remove or move such meter or equipment.

8.4 Energy Source Meters - The Seller shall, at its cost, ensure that meters are installed at the Seller's Plant capable of measuring the Energy Source available to the Seller's Plant.

9. STATEMENTS AND PAYMENT

9.1 Statements

(a) In each month after the month in which Pre-COD Energy is first delivered to the Buyer, the Seller shall, by the 15th day of the month or the first Business Day thereafter, deliver to the Buyer a statement prepared by the Seller for the preceding month. The statement must comply with any billing guideline issued by the Buyer pursuant to section 9.4 and must indicate, among other things, the amount of Eligible Energy, the price payable for the Eligible Energy, any LDs payable by the Seller to the Buyer and any Final Amounts owing by either Party to the other Party and set out in reasonable detail the manner by which the statement and the amounts shown thereon were computed. To the extent not previously delivered pursuant to the requirements of this EPA, the statement must be accompanied by sufficient data to enable the Buyer, acting reasonably, to satisfy itself as to the accuracy of the statement.

(b) Either Party may give notice to the other Party of an error, omission or disputed amount on a statement within 36 months after the statement was first issued together with reasonable detail to support its claim. After expiry of that 36 month period, except in the case of wilful misstatement or concealment, amounts on a previously issued statement will be considered accurate and amounts which were omitted will be considered to be nil, other than amounts disputed in accordance with this subsection within the 36 month period, which will be resolved in accordance with this EPA.

9.2 Payment

(a) Within 30 days after receipt of a statement delivered pursuant to subsection 9.1(a) and subject to sections 9.5 and 13.6, the Buyer shall pay to the Seller the amount set out in the statement, except to the extent the Buyer in good faith disputes all or part of the statement by notice to the Seller in compliance with subsection 9.1(b). If the Buyer disputes any portion of a statement, the Buyer must nevertheless pay the undisputed net amount payable by the Buyer pursuant to the statement.

(b) Any amount required to be paid in accordance with this EPA, but not paid by either Party when due, will accrue interest at an annual rate equal to the Prime Rate plus 3%, compounded monthly. Any disputed amount that is found to be payable will be deemed to have been due within 30 days after the date of receipt of the statement which included or should have included the disputed amount.

9.3 Taxes - All dollar amounts in this EPA do not include any value added, consumption, commodity or similar taxes applicable to the purchase by the Buyer of the Eligible Energy, including GST and PST, which, if applicable, will be borne by the Buyer and added to each statement.

9.4 Billing Guideline - The Seller shall comply with any reasonable written billing guideline (including any requirements with respect to the form of statements pursuant to section 9.1) issued by the Buyer during the Term, provided that any such billing guideline shall not vary the express terms of this EPA. If there is any conflict between a billing guideline and this EPA, this EPA will govern.

9.5 Set-off - If the Buyer and the Seller each owe the other an amount under this EPA in the same month, then such amounts with respect to each Party shall be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount shall pay to the other Party the difference between the amounts owed, provided that:

(a) this section 9.5 applies only to any purchase price for Eligible Energy owing by the Buyer to the Seller, any LDs owing by the Seller to the Buyer, any Termination Payment or Final Amount owing by either Party to the other Party and any amount owing by the Seller to the Buyer under section 6.8; and

(b) no LD, Termination Payment, Final Amount or amount owing by the Seller to the Buyer under section 6.8 shall be added to or deducted from the price owing by the Buyer to the Seller for Eligible Energy unless the LD, Termination Payment, Final Amount or amount owing under section 6.8 remains unpaid 30 days after the Party owed the LD, Termination Payment, Final Amount or amount owing under section 6.8 gives notice to the other Party.

Except as otherwise expressly provided herein, each Party reserves all rights, counterclaims and other remedies and defences which such Party has or may be entitled to arising from or related to this EPA.

10. INSURANCE/DAMAGE AND DESTRUCTION

10.1 Insurance - The Seller shall, by the date specified in section 4.1 for the commencement of the Project activities necessary to construct the Seller's Plant, obtain, maintain and pay for: (a) policies of commercial general liability insurance with a per occurrence limit of liability not less than $__________ applicable to the Project separate from all other projects and operations of the Seller; and (b) property insurance and Construction Insurance with limits of liability and deductibles consistent with those a prudent owner of a facility similar to the Seller's Plant would maintain and those the Facility Lender requires. All commercial general liability policies must include the Buyer, its directors, officers, employees and agents as additional insureds and must contain a cross liability and severability of interest clause. All policies of insurance must be placed with insurers that have a minimum rating of A- (or equivalent) by A.M. Best Company and are licensed to transact business in the Province of British Columbia and must be endorsed to provide to the Buyer 30 days prior written notice of cancellation, non-renewal or any material amendment that results in a reduction in coverage. The Seller shall give the Buyer a copy of the insurance certificate(s) for the insurance required to be maintained by the Seller under this section not more than 30 days after the effective date of coverage and immediately upon renewal thereafter. The Seller shall be responsible for the full amount of all deductibles under all insurance policies required to be maintained by the Seller under this section.

[Note to Bidders: The insurance policy limit of liability set out in section 10.1 of the Awarded EPA will be based on the Plant Capacity as follows:

Greater than 10 MW to 25 MW	-	***$ 3,000,000***
Greater than 25 MW to 50 MW	-	***$ 5,000,000***
Greater than 50 MW to 100 MW	-	***$10,000,000***
Greater than 100 MW	-	***$20,000,000]***

10.2 Damage or Destruction of the Seller's Plant

(a) **Major Damage -** If the Seller's Plant suffers Major Damage caused by a Force Majeure event in respect of which the Seller has invoked Force Majeure in accordance with Article 11, then the Seller may at its option exercisable by notice to the Buyer within 120 days after the occurrence thereof, either: (i) proceed to diligently and expeditiously and at its own cost repair the Major Damage and restore the Seller's Plant to at least the condition in which it was in immediately prior to the Major Damage and resume deliveries of Energy hereunder; or (ii) terminate this EPA, and in that event, the provisions of section 15.3 and subsection 15.5(c) apply. If the Seller fails to give notice exercising its option within such 120 day period, it will be deemed to have exercised the option described in (i) above. Nothing in this section limits the rights of either Party to terminate this EPA under any other section of this EPA.

(b) **Non-Major Damage -** If the Seller's Plant is damaged or destroyed, in whole or in part, by any cause or peril, then, except in the case of Major Damage caused by a Force Majeure event in respect of which the Seller has invoked Force Majeure in accordance with Article 11, the Seller shall within 30 days after the date of the damage or destruction provide notice to the Buyer setting out the date by which the Seller, acting reasonably, can resume delivering Energy to the Buyer which date shall be not more than 365 days after the date of occurrence of the damage or destruction. The Seller shall diligently and expeditiously, and at its own cost, repair the Seller's Plant and restore the same to at least the condition in which it was in immediately prior to the damage or destruction and shall complete such work not later than the date specified in the notice delivered by the Seller to the Buyer under this section. Nothing in this section limits the rights of either Party to terminate this EPA under any other section of this EPA.

(c) **Extension of Term -** Provided the Seller complies with its obligations under this section 10.2, the Term shall be extended by the number of days from the date of the event of damage or destruction to the date on which the Seller resumes delivering Energy to the Buyer.

11. FORCE MAJEURE

11.1 Invoking Force Majeure and Notice

(a) Neither Party will be in breach or default as to any obligation under this EPA if that Party is unable to perform that obligation due to an event or circumstance of Force Majeure, of which notice is given as required in this section 11.1 and, subject to any limitations expressly set out in this EPA, the time for performance of such obligation will be extended by the number of days that Party is unable to perform such obligation as a result of the event or circumstance of Force Majeure.

(b) If there is a Force Majeure preventing a Party from performing an obligation under this EPA, that Party shall promptly notify the other Party of the Force Majeure. The notice must identify the nature of the Force Majeure, its expected duration and the particular obligations affected by the Force Majeure. The affected Party shall provide reports to the other Party with respect to the Force Majeure at such intervals as the other Party may reasonably request while the Force Majeure continues. A Party will be deemed to have invoked Force Majeure from the date when that Party gives notice of the Force Majeure in accordance with this subsection 11.1(b), provided that if such notice is given within 24 hours after the later of: (i) the occurrence of the Force Majeure; and (ii) the time when the Party knew, or reasonably ought to have known, of the occurrence of the Force Majeure, the Party will be deemed to have invoked Force Majeure from the date on which the event of Force Majeure occurred. The Party invoking Force Majeure shall promptly respond to any inquiry from the other Party regarding the efforts being undertaken to remove the Force Majeure. The Party invoking Force Majeure shall give prompt notice of the end of the Force Majeure.

11.2 Exclusions - A Party may not invoke Force Majeure:

(a) for any economic hardship, or for lack of money, credit or markets; or

(b) if the Force Majeure is the result of a breach by the Party seeking to invoke Force Majeure of a Permit or of any applicable Laws; or

(c) for a mechanical breakdown, unless the Party seeking to invoke Force Majeure can demonstrate by clear and convincing evidence that the mechanical breakdown was caused by a latent defect in the design or manufacture of the equipment which could not reasonably have been identified by normal inspection or testing of the equipment; or

(d) if the Force Majeure was caused by a breach of, or default under, this EPA or a wilful or negligent act or omission by the Party seeking to invoke Force Majeure; or

(e) for any acts or omissions of third parties, including any Affiliate of the Seller, or any vendor, supplier, contractor or customer of a Party, but excluding Governmental Authorities, unless such acts or omissions are themselves excused by reason of Force Majeure as defined in this EPA; or

(f) for any disconnection of the Seller's Plant from the Transmission System, or any Outage, suspension, constraint or curtailment in the operation of the Transmission System; or

(g) based on the cost or unavailability of the Energy Source for any reason, including natural causes, unless: (i) transport of the Energy Source to the Seller's Plant is prevented by an event or circumstance that constitutes Force Majeure (as defined in this EPA); or (ii) if the Energy Source is water, wind or solar, the Seller can demonstrate by clear and convincing evidence that the unavailability of the Energy Source is caused by a significant landslide, earthquake or volcanic eruption resulting in a significant reduction in the flow of the Energy Source to the Seller's Plant.

12. LIQUIDATED DAMAGES

12.1 COD Delay - If the Seller's Plant fails to achieve COD by the date that is the earlier of:

(a) 185 days after the Guaranteed COD plus Force Majeure Days, and

(b) the COD Deadline plus Force Majeure Days,

the Seller shall pay COD Delay LDs to the Buyer in an amount equal to the amount determined in accordance with subsection (b) of the definition of "Performance Security" divided by 180 for each day COD is delayed to a maximum of 180 days. The Seller shall pay any COD Delay LDs owing by the Seller to the Buyer in respect of the immediately preceding month on the 30th day after the last day of that month.

12.2 Delivery Shortfalls - If in any month after the first anniversary of COD, the Delivered Eligible Energy during the month is less than 90% of the Monthly Firm Energy Amount for that month, the Seller shall pay LDs to the Buyer calculated as follows:

LD Amount = LD Factor * ((0.9 * Monthly Firm Energy Amount) - Delivered Eligible Energy)

Where:

(a) the Monthly Firm Energy Amount is the amount set out in Appendix 2 for the relevant month less an amount equal to the Monthly Firm Energy Amount divided by the number of minutes in the month for each minute in which the Seller is excused under subsection 7.8(a) from the obligation to deliver Energy; and

(b) "Delivered Eligible Energy" means in each month the amount of Eligible Energy determined pursuant to subsection (a) of the definition of Eligible Energy for that month, but excluding any Energy delivered after the start time and prior to the end time for an

Authorized Planned Outage as set out in the notice with respect to the Authorized Planned Outage under section 6.4;

(c) LD Factor = the greater of: (i) zero and (ii) A-[(EBP/(1-L))+EBPA]

Where:

(i) A = the lesser of:

(I) the LD Cap; and

(II) the Mid-C Index;

(ii) L = ________%

(iii) EBP = Escalated Bid Price

(iv) EBPA (Escalated Bid Price Adjuster)$_n$ = $____/MWh * $CPI_{January\ 1\ n}/CPI_{January\ 1\ 2006}$

Where:

n = the year for which the Escalated Bid Price Adjuster is being calculated

$CPI_{January\ 1\ n}$ = the CPI for December in the year immediately preceding the year for which the Escalated Bid Price Adjuster is being calculated.

[Note to Bidders – L will be the greater of (i) zero and (ii) an amount determined from the energy loss information used in the CFT evaluation. EBPA will be the sum of the following: -3.00 if the Green Attributes are transferred to BC Hydro; -3.00 if the Bidder tendered an Hourly Firm Energy Profile; and X if GHG emission offset obligations are transferred to BC Hydro where "X" is the amount determined from the GHG Adjustment Table (CFT Reference Document), based on the Bidder's tendered Guaranteed GHG Intensity.]

(v) Mid-C means the mid-Columbia electricity region;

(vi) "Mid-C Index" means the weighted average for the relevant month of the Dow Jones Mid-C daily firm On-Peak Index and the Dow Jones Mid-C daily firm Off-Peak Index weighted based on the number of on-peak and off-peak hours (as defined in the Mid-C index) in the relevant month. Amounts quoted in U.S. dollars will be converted to Canadian dollars using the average of the Bank of Canada daily "noon rates" for the applicable month;

(vii) "LD Cap" means $100/MWh adjusted effective as of January 1 in each year after the Effective Date in accordance with the following formula:

LD Cap$_n$ = $100/ MWh * $CPI_{January\ 1\ n}/CPI_{January\ 1\ 2006}$

Where:

n = the year for which the escalated LD Cap is being calculated

$CPI_{January\ 1\ n}$ = the CPI for December in the year immediately preceding the year for which the escalated LD Cap is being calculated.

Any LDs owing by the Seller to the Buyer pursuant to this section 12.2 shall be payable on 15th day of the month following the month in which the delivery shortfall occurred.

12.3 Exclusive Remedies for Buyer - Except in the case of Deliberate Breach, payment by the Seller of the LDs in this Article 12 is the exclusive remedy to which the Buyer is entitled for: (i) the Seller's failure to achieve COD by the Guaranteed COD; (ii) the Seller's failure to deliver the Monthly Firm Energy Amount; or (iii) any other failure to comply with section 7.3 or the last sentence of section 6.3, provided that the foregoing does not limit or otherwise affect any right to receive interest on LDs or any right to terminate the EPA, or any right to receive a Termination Payment, in each case as expressly set out in this EPA, or the exercise of any other right or remedy expressly set out in this EPA, including any rights under section 9.5, or Article 13, or any right to apply any invoice adjustments in accordance with Appendix 3.

12.4 Exclusive Remedies for Seller - The Seller's exclusive remedy for the Buyer's failure to take or pay for Eligible Energy is a claim for the price payable by the Buyer for Eligible Energy pursuant to Appendix 3 and any interest on any such amount owing by the Buyer to the Seller, provided that the foregoing does not limit or otherwise affect any right to terminate the EPA, any rights under section 9.5, or any right to receive a Termination Payment expressly set out in this EPA.

12.5 Limits of Liability - Except in the case of Deliberate Breach, in each year during the Term the Seller's liability for damages for all breaches of, or defaults under, this EPA in that year is limited to an amount equal to 200% of the required amount of the Performance Security for the relevant year, provided that the foregoing does not apply to: (i) any liability under any of sections 4.2, 4.5, 5.7, or 6.8; (ii) any liability under section 19.1; (iii) interest on any amount owing under this EPA; (iv) any right to receive a Termination Payment expressly set out in this EPA; or (v) any other provision in this EPA that is expressly excluded from the limits of liability in this section.

12.6 Consequential Damages - Neither Party shall be liable to the other Party for any special, incidental, exemplary, punitive or consequential damages arising out of a Party's performance or non-performance under this EPA, whether based on or claimed under contract, tort, strict liability or any other theory at law or in equity.

13. PERFORMANCE SECURITY

13.1 Delivery - The Parties acknowledge that the Seller has delivered the Performance Security, in the form required pursuant to section 13.4, to the Buyer concurrently with execution and delivery of this EPA. The Seller shall maintain the Performance Security until the time provided in section 13.2. The Performance Security secures the obligations of the Seller under this EPA, but is not a limitation of the Seller's liability in respect of any breach of, or default under, this EPA.

13.2 Return - The Buyer shall return or release the Performance Security to the Seller, without deduction, other than prior deductions, if any, properly made hereunder on the earlier of:

(a) upon termination of this EPA under section 3.1, by the date specified in subsection 3.5(a); or

(b) 10 Business Days after termination of this EPA under subsection 10.2(a), section 15.1 or section 15.2 and discharge of all obligations and liabilities of the Seller to the Buyer under this EPA.

13.3 Enforcement - If:

(a) the Seller fails to pay amounts owing by the Seller to the Buyer pursuant to any of sections 4.2, 4.5, 5.7, or 6.8; or

(b) the Seller fails to pay any Final Amount owing by the Seller to the Buyer; or

(c) the Seller fails to pay any LDs owing by the Seller to the Buyer; or

(d) the Seller fails to pay any Termination Payment owing by the Seller to the Buyer,

and, in each case, the Seller fails to cure such failure to pay within 15 days after notice from the Buyer to the Seller, then the Buyer may enforce the Performance Security and apply the proceeds thereof on account of amounts owing to the Buyer in respect of any or all of the foregoing.

13.4 Form - The Seller shall maintain the Performance Security in the form of a letter of credit that is:

(a) issued or advised by a branch in Vancouver, Canada of a bank or financial institution where the issuing bank or financial institution has a credit rating not less than Standard & Poor's A-, Moody's A3 or Dominion Bond Rating Service A (low) and if such credit rating agencies publish differing credit ratings for the same bank or financial institution, the lowest credit rating of any of the credit rating agencies shall apply for purposes of this section;

(b) in the form set out in Appendix 6, or in such other form as agreed to by the Buyer; and

(c) for a term of not less than one year and must provide that it is renewed automatically, unless the issuing or confirming bank advises otherwise by the date specified in Appendix 6.

13.5 Replenishment - If the Buyer draws on the Performance Security, as permitted hereunder, then the Seller shall within 3 Business Days after such draw provide additional security in the form specified in section 13.4 sufficient to replenish or maintain the aggregate amount of the Performance Security at the amount required hereunder.

13.6 Right to Withhold Payment - If the Seller has failed to maintain the Performance Security at the level required hereunder (subject to the cure period specified in section 13.5), the Buyer shall be entitled to withhold payment of any amount owing by the Buyer to the Seller under this EPA until 5 days after the date when the Seller has delivered the required amount of Performance Security to the Buyer. Any amounts withheld by the Buyer in accordance with this section 13.6 will not bear interest.

13.7 Letter of Credit Failure - The Buyer shall be entitled to enforce the Performance Security in the event of a Letter of Credit Failure and the Buyer shall be entitled to hold the proceeds of such enforcement until such time as the Seller delivers replacement Performance Security in the amount and in the form required under this EPA. Upon receipt of such replacement security, the Buyer shall return the proceeds of enforcement of the original Performance Security to the Seller without interest after deducting any amounts the Buyer is entitled to deduct under this EPA. The Seller shall notify the Buyer promptly of any Letter of Credit Failure.

14. SUSPENSION

14.1 Buyer Suspension - If a Buyer Termination Event has occurred and is continuing, the Buyer may, upon notice to the Seller, suspend performance under this EPA provided that in no event shall any such suspension continue for longer than 90 days and further provided that such right shall not affect the Buyer's obligation to make any payment owing to the Seller in respect of performance by the Seller of its obligations under this EPA prior to the date of suspension by the Buyer.

14.2 Seller Suspension - If a Seller Termination Event has occurred and is continuing, the Seller may, upon notice to the Buyer, suspend performance under this EPA, provided that such right shall not affect the Seller's obligation to pay any amount owing by the Seller to the Buyer in respect of performance of, or failure to perform, the Seller's obligations under this EPA prior to the date of suspension by the Seller.

14.3 Resuming Deliveries - The non-defaulting Party's right to suspend performance pursuant to this Article 14 shall cease when the defaulting Party has demonstrated to the satisfaction of the non-defaulting Party, acting reasonably, that the defaulting Party has cured the cause for the suspension.

15. TERMINATION

15.1 Termination by the Buyer - In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA, the Buyer may terminate this EPA, by notice to the Seller if:

(a) the Seller has failed to obtain all Material Permits by the date that is 365 days prior to the Guaranteed COD, provided that the Buyer shall only be entitled to terminate the EPA under this provision if the Buyer delivers a termination notice prior to the date on which the Seller has secured all Material Permits; or

(b) COD does not occur by the earlier of:

(i) the Guaranteed COD plus 365 days plus all Force Majeure Days (not exceeding 365 Force Majeure Days); and

(ii) the COD Deadline plus 180 days plus all Force Majeure Days (not exceeding 185 Force Majeure Days),

provided that the Buyer shall only be entitled to terminate the EPA under this provision if the Buyer delivers a termination notice prior to COD, and further provided that if the Buyer has not exercised its right to terminate the EPA within 30 days after the right to terminate arises under this subsection, the Seller may deliver a notice to the Buyer setting out a new date by which the Seller, acting reasonably, expects to achieve COD. If the Buyer does not elect to terminate the EPA within 60 days after receipt of such a notice, the Buyer shall only be entitled to terminate this EPA under this provision if the Seller does not achieve COD by the date specified in such notice; or

(c) at any time after COD, the Buyer has received a notice from the Seller invoking Force Majeure and:

(i) the Force Majeure has not been removed by the date that is 365 days after the date of the notice invoking Force Majeure; or

(ii) if the Force Majeure cannot be removed within that 365 day period, by the date that is 730 days after the date of the notice invoking Force Majeure, provided that the Seller is working diligently and expeditiously to remove the Force Majeure.

The Buyer shall only be entitled to terminate the EPA under this provision if the Buyer delivers a termination notice prior to the end of the Force Majeure; or

(d) a Buyer Termination Event occurs.

Any termination pursuant to this section 15.1 shall be effective immediately upon delivery of the notice of termination to the Seller.

15.2 Termination by the Seller - In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA, the Seller may terminate this EPA by notice to the Buyer if:

(a) the Seller, after using commercially reasonable efforts, has failed to obtain all Material Permits on terms satisfactory to the Seller, acting reasonably, on or before the date that is 545 days before the Guaranteed COD, provided that if the Seller has not given notice of termination pursuant to this subsection 15.2(a) by the date that is 15 days after the Seller's right to terminate arises under this subsection 15.2(a), the Seller will be deemed to have elected not to terminate this EPA and will not thereafter be entitled to terminate this EPA under this subsection 15.2(a); or

[Note to Bidders: The foregoing subsection will not be included in any EPA where this right to terminate has expired prior to execution of the EPA]

(b) the Seller has received a notice from the Buyer invoking Force Majeure and the Force Majeure has not been removed by the date that is 365 days after the date of notice invoking Force Majeure, provided that the Seller shall only be entitled to terminate the EPA under this provision if the Seller delivers a termination notice prior to the end of the Force Majeure; or

(c) a Seller Termination Event occurs.

Any termination pursuant to this section 15.2 shall be effective immediately upon delivery of the notice of termination to the Buyer.

15.3 Effect of Termination - Upon expiry of the Term or if this EPA is terminated pursuant to section 3.1, subsection 10.2(a) or this Article 15:

(a) the Parties may pursue and enforce any rights and remedies permitted by law or equity in respect of any prior breach or breaches of the EPA, and may enforce any liabilities and obligations that have accrued under this EPA prior to the expiry of the Term or the date of termination (including any claims by the Buyer for amounts that would have been payable by the Seller under any of sections 4.2, 4.5, 5.7 or 6.8 but for the expiry or termination of the EPA), subject to any express restrictions on remedies and limitations or exclusions of liability set out in this EPA; and

(b) (i) with respect to a termination under section 3.1 only, both Parties will remain bound by (A) Article 19 and sections 20.7 and 20.8, and (B) sections 3.3, 3.5, 13.2 and 13.3, in respect of the satisfaction of residual obligations specified to arise on termination only;

(ii) upon expiry of the Term or upon any termination other than a termination under section 3.1:

(A) both Parties will remain bound by: (I) section 7.10; (II) Article 9 in respect of any final billing and resolution of disputed amounts only, (III) Article 13 and Article 15, in respect of the satisfaction of residual obligations specified to arise on termination only; and (IV) Article 19 and sections 20.7 and 20.8; and

(B) the Seller will remain bound by: (I) section 6.5; and (II) for a period of 36 months following expiry of the Term or termination of this EPA, Article 17, with respect to records only,

and, in all such cases, both Parties will remain bound by any other provisions necessary for the interpretation and enforcement of the foregoing provisions.

15.4 Payment on Termination by the Buyer

(a) If the Buyer terminates this EPA under section 15.1, except for a termination pursuant to subsection 15.1(c), the Seller shall pay to the Buyer an amount equal to $60,000/MW multiplied by the Plant Capacity where termination occurs prior to the first anniversary of COD, or, where termination occurs on or after the first anniversary of COD, an amount equal to $40,000/MW multiplied by the total of the Monthly Firm Energy Amounts set out in Appendix 2 divided by 8760.

(b) If the Buyer terminates this EPA under subsection 15.1(c), no Termination Payment is payable by the Seller to the Buyer, except as set out in subsection 15.4(c).

(c) If the Buyer terminates this EPA under subsection 15.1(c) prior to the first anniversary of COD, the Seller shall reimburse the Buyer, within 30 days after the date of delivery by the Buyer to the Seller of an invoice therefor (which invoice shall be delivered not later than 60 days after the date of termination of the EPA), for an amount, not exceeding the amount of the Performance Security required hereunder, equal to the Network Upgrade Costs.

15.5 Payment on Termination by the Seller

(a) If the Seller terminates this EPA under subsection 15.2(a), the Seller shall pay to the Buyer an amount equal to $20,000/MW multiplied by the total of the Monthly Firm Energy Amounts set out in Appendix 2 divided by 8760.

(b) If the Seller terminates this EPA under subsection 15.2(b), no Termination Payment is payable by the Buyer to the Seller.

(c) If the Seller terminates this EPA under subsection 10.2(a), no Termination Payment is payable by the Seller to the Buyer except that if the Seller terminates the EPA under subsection 10.2(a) prior to the first anniversary of COD, subsection 15.4(c) applies.

(d) If the Seller terminates this EPA under subsection 15.2(c) prior to COD, the Buyer shall pay to the Seller an amount equal to the lesser of:

(i) 115% of the Development Costs; and

(ii) the positive amount, if any, by which the Seller's Losses and Costs exceed its aggregate Gains.

(e) If the Seller terminates this EPA under subsection 15.2(c) after COD, the Buyer shall pay to the Seller an amount equal to the positive amount, if any, by which the Seller's Losses and Costs exceed its aggregate Gains.

(f) The Buyer may audit the Seller's Development Costs and in that event, the Seller shall provide all reasonable cooperation to the Buyer or its designated representative, including access to all original records related to Development Costs.

(g) The Seller's Gains, Losses and Costs shall be determined by comparing the value of the remaining Term, contract quantities and price payable under this EPA had it not been terminated to the relevant market prices for equivalent quantities for the remaining Term either quoted by a bona fide arm's length third party or which are reasonably expected to be available in the market under a replacement contract for this EPA. Market prices will be adjusted for differences between the product subject to the market prices and the product specified under this EPA including with respect to quantity, place of delivery and length of term.

(h) The Seller shall not be required to enter into a replacement transaction in order to determine the amount payable by the Buyer pursuant to subsection 15.5(d) or (e).

(i) The Seller shall determine the amount of any Termination Payment owed by the Buyer pursuant to subsection 15.5(d) or (e) as applicable and shall notify the Buyer of such amount and provide reasonable particulars with respect to its determination within 120 days after the effective date of termination of this EPA, failing which the Seller will not be entitled to any Termination Payment under this section.

(j) If the Seller's aggregate Gains exceed its aggregate Losses and Costs, if any, resulting from the termination of this EPA, the amount of the Termination Payment shall be zero.

(k) The Seller's Gains, Losses and Costs will be discounted to the present value of those Gains, Losses and Costs at the effective date of termination of the EPA (to take into account the time value of money for the period between the effective date of termination of the EPA and the date the Gains, Losses and Costs would have occurred but for the termination of the EPA) using the Present Value Rate applicable at the effective date of termination of the EPA, where the "Present Value Rate" means the annual yield on a Government of Canada Bond having a maturity date that most closely matches the date on which the Term would have expired but for the termination of the EPA, plus 3%.

15.6 Termination Payment Date - A Party required to make a Termination Payment to the other Party shall, except in the case of a Termination Payment payable pursuant to subsection 15.5(d) or (e), pay the Termination Payment within 5 Business Days after the effective date of termination of this EPA. The Buyer shall pay any Termination Payment owing by the Buyer pursuant to subsection 15.5(d) or (e) within 30 Business Days after the date of delivery of an invoice by the Seller to the Buyer pursuant to subsection 15.5(d) or (e) as applicable. At the time for payment of the Termination Payment, each Party shall pay to the other Party all additional amounts payable by it pursuant to this EPA, but all such amounts will be netted and aggregated with any Termination Payment.

15.7 Exclusive Remedies - Subject to section 15.3, the payments and actions contemplated by section 3.5 shall be the exclusive remedy to which the Parties are entitled for termination of this EPA pursuant to section 3.1. Except in the case of Deliberate Breach or as otherwise expressly set out in this EPA, and subject to section 15.3: (a) payment by the Seller of the Termination Payment is the exclusive remedy to which the Buyer is entitled for termination of this EPA pursuant to subsections 15.1(a), (b) or (d) or 15.2(a); and (b) payment by the Seller of any amount payable pursuant to subsection 15.4(c) is the exclusive remedy to which the Buyer is entitled for termination of this EPA pursuant to subsection 15.1(c). Payment by the Buyer of the Termination Payment is the exclusive remedy to which the Seller is entitled for termination of this EPA pursuant to subsection 15.2(c). Termination of this EPA is the exclusive remedy to which the Seller is entitled for termination of this EPA pursuant to subsection 15.2(b).

16. ASSIGNMENT

16.1 Assignment - A Party may not assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term, except:

(a) with the consent of the other Party, such consent not to be unreasonably withheld, delayed or conditioned; or

(b) to an Affiliate, on notice to, but without the consent of, the other Party, provided that the assignor will remain liable for the obligations of the assignee under this EPA, unless otherwise agreed in writing by the other Party.

Notice of intent to assign, and where applicable a request for consent to assign, must be given by the assignor to the other Party not less than 30 days before the date of assignment, and, except in the case of assignment to a Facility Lender, must be accompanied by a proposed form of assignment and assumption agreement, and, in the case of an assignment pursuant to subsection 16.1(a), other than to a Facility Lender, evidence of the capability of the assignee as required by subsection 16.2(b). Consent to an assignment to a Facility Lender will not be given or be deemed to be given until full execution and delivery of the agreement contemplated by section 16.3. Any sale or other disposition of all or a substantial part of the Seller's ownership interest in the Seller's Plant, or of all or any interest of the Seller in this EPA or revenue derived from this EPA, and any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's ownership interest in the Project Assets and any change of Control, merger, amalgamation or reorganization of the Seller is deemed to be an assignment of this EPA by the Seller for the purpose of this Article 16, including section 16.2, provided that where Control is transferred to an Affiliate or where the Seller merges or amalgamates with an Affiliate or enters into a reorganization with an Affiliate, subsection 16.1(b) shall apply.

16.2 Preconditions to Assignment - Without limiting subsection 16.1(a), any assignment pursuant to section 16.1 (other than an assignment to a Facility Lender) is subject to:

(a) the assignee entering into and becoming bound by this EPA, assuming all the obligations and liabilities of the assignor under the EPA arising both before and after the assignment of the EPA, providing any Performance Security, as applicable at the time of assignment and providing the representations and warranties set out in section 18.1 effective as at the time of assignment; and

(b) except for an assignment under subsection 16.1(b), the assignee demonstrating to the reasonable satisfaction of the other Party its capability (financial, technical and otherwise) to fulfil the obligations of the assignor under this EPA or, in the case of a change of Control, merger, amalgamation or reorganization of the Seller, the parties to that transaction demonstrating to the reasonable satisfaction of the Buyer, the continued ability of the Seller to perform its obligations under this EPA and, in the case only of an assignment of 100% of the assignor's interest in the Project Assets, the Seller's Plant, or this EPA or revenue derived from this EPA, upon such demonstration and concurrently with the agreement providing for the assumption of liabilities and obligations and the provision of Performance Security required under subsection 16.2(a), the assignor shall be released from all future obligations and liabilities under the EPA and the Performance Security provided by it will be returned or released.

16.3 Assignment to Facility Lender - If the Seller seeks consent to assign this EPA to a Facility Lender or Facility Lenders, the Seller acknowledges that the Buyer is entitled to require, as a condition of the Buyer's consent to such assignment, that the Seller and the Facility Lender enter into an agreement with the Buyer substantially in the form attached as Appendix 7.

16.4 No Implied Consent to Exercise of Rights - No consent to any assignment given by the Buyer under this Article 16 implies or constitutes a consent to the exercise by the assignee, or any Affiliate of the assignee, whether or not a Facility Lender, of any right if the exercise of that right, at the time it was acquired, would require the consent of the Buyer under this Article 16, and the exercise of any such right will require the further consent of the Buyer.

16.5 Costs - The assignor shall reimburse the other Party for all costs reasonably incurred in connection with an assignment.

16.6 No Assignment Before COD - Notwithstanding subsection 16.1(a), the Seller shall not assign (including any event or action that is deemed under section 16.1 to be an assignment) or otherwise dispose of any interest in this EPA prior to COD, except: (i) to an Affiliate as permitted under subsection 16.1(b); (ii) to a Facility Lender as permitted under subsection 16.1(a) and section 16.3; or (iii) with the prior consent of the Buyer, which consent may be given, withheld or conditioned in the unfettered discretion of the Buyer.

17. INSPECTION

For the sole purpose of verifying compliance with this EPA, of verifying the accuracy of invoices and other statements or calculations delivered by the Seller to the Buyer under this EPA and of verifying the Seller's right to rely on any relief claimed by the Seller under this EPA, on reasonable prior notice to the Seller, the Seller shall provide the Buyer and the Buyer's representatives and advisors with prompt access during normal business hours to the Seller's Plant and to the records relating to the Seller's Plant including all records required to be maintained by the Seller under section 6.5 and the Seller shall promptly provide copies of any such records to the Buyer on request by the Buyer at any time. The Buyer and the Buyer's representatives and advisors may take copies of all such records. All such records that contain confidential technical or proprietary information are Confidential Information under section 20.8. The Buyer shall exercise any access under this Article 17 at the Buyer's cost and in a manner that minimizes disruption to the operation of the Seller's Plant. Any review, inspection or audit by the Buyer of the Seller's Plant, its design, construction, operation, maintenance, repair, records or other activities of the Seller may not be relied upon by the Seller, or others, as confirming or approving those matters.

18. REPRESENTATIONS AND WARRANTIES

18.1 By Seller - The Seller represents and warrants to the Buyer, and acknowledges that the Buyer is relying on those representations and warranties in entering into this EPA, as follows:

(a) **Corporate Status -** The Seller is duly incorporated, organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation, is registered or otherwise lawfully authorized to carry on business in British Columbia, and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and to perform its obligations under this EPA;

(b) **Bankruptcy -** No actions have been taken or authorized by the Seller or any other Person to initiate proceedings for, or in respect of, the bankruptcy, insolvency, liquidation, dissolution or winding-up of the Seller or to appoint a receiver, liquidator, trustee or assignee in bankruptcy in respect of the Seller;

(c) **Assets -** No appropriation, expropriation or seizure of all or any portion of the Seller's Plant is pending or threatened;

(d) **No Conflict -** Neither the signing of this EPA, nor the carrying out of the Seller's obligations under this EPA will: (i) constitute or cause a breach of, default under, or violation of, the constating documents or bylaws of the Seller, any permit, franchise, lease, license, approval or agreement to which the Seller is a party, or any other covenant or obligation binding on the Seller or affecting any of its properties; (ii) cause a lien or encumbrance to attach to the Seller's Plant, other than a security interest granted in respect of financing the design, construction or operation of the Seller's Plant; or (iii) result in the acceleration, or the right to accelerate, any obligation under, or the termination of, or the right to terminate, any permit, franchise, lease, license, approval or agreement related to the Seller's Plant;

(e) **Binding Obligation -** This EPA constitutes a valid and binding obligation of the Seller enforceable against the Seller in accordance with its terms;

(f) **Authorization, Execution and Delivery -** This EPA has been duly authorized, executed and delivered by the Seller;

(g) **Bid Documents -** All material information in the Bid Documents is true and correct in all material respects and there is no material information omitted from the Bid Documents which makes the information in the Bid Documents misleading or inaccurate in any material respect; and

(h) **Exemption From Regulation -** The Seller is exempt from regulation as a "public utility", as defined in the UCA, with respect to the Seller's Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA.

18.2 By Buyer - The Buyer represents and warrants to the Seller, and acknowledges that the Seller is relying on those representations and warranties in entering into this EPA, as follows:

(a) **Corporate Status -** The Buyer is a corporation continued under the *Hydro and Power Authority Act*, R.S.B.C. 1996, c. 212, is validly existing and is in good standing under the laws of British Columbia, is lawfully authorized to carry on business in British Columbia, and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and to perform its obligations under this EPA;

(b) **Bankruptcy -** No actions have been taken or authorized by the Buyer or any other Person to initiate proceedings for, or in respect of, the bankruptcy, insolvency, liquidation, dissolution or winding-up of the Buyer or to appoint a receiver, liquidator, trustee or assignee in bankruptcy in respect of the Buyer;

(c) **Assets -** There is no appropriation, expropriation or seizure of any of the material assets of the Buyer pending or threatened;

(d) **No Conflict -** Neither the signing of this EPA nor the carrying out of the Buyer's obligations under this EPA will constitute or cause a breach of, default under, or violation of, the *Hydro and Power Authority Act* (British Columbia), any permit, franchise, lease, license, approval or agreement to which the Buyer is a party, or any other covenant or obligation binding on the Buyer or affecting any of its properties;

(e) **Binding Obligation -** This EPA constitutes a valid and binding obligation of the Buyer enforceable against the Buyer in accordance with its terms; and

(f) **Authorization, Execution and Delivery -** This EPA has been duly authorized, executed and delivered by the Buyer.

19. INDEMNITIES

19.1 Seller Indemnity - The Seller shall indemnify, defend and hold harmless the Buyer and its shareholder(s) and Affiliates, and their respective directors, officers, employees, agents, representatives, successors and permitted assigns (the "**Buyer Indemnified Parties**") from and against all claims, demands, actions, causes of action, suits, orders and proceedings made or brought against any of the Buyer Indemnified Parties:

(a) with respect to any emissions from the Seller's Plant; or

(b) for personal injury, including death, to third Persons and for damage to property of third Persons, to the extent caused or contributed to by the wilful act or omission or negligence of the Seller, any contractor or subcontractor or supplier to the Seller or any director, officer, employee or agent of the Seller or any other Person for whom the Seller is responsible at law where such wilful act or omission or negligence is in connection with the Project or the performance of, or the failure to perform, any of the Seller's obligations under this EPA.

19.2 Buyer Indemnity - The Buyer shall indemnify, defend and hold harmless the Seller and its shareholder(s) and Affiliates, and their respective directors, officers, employees, agents, representatives, successors and permitted assigns (the "**Seller Indemnified Parties**") from and against all claims, demands, actions, causes of action, suits, orders and proceedings made or brought against any of the Seller Indemnified Parties for personal injury, including death, to third Persons and for damage to property of third Persons, to the extent caused or contributed to by the wilful act or omission or negligence of the Buyer, any contractor or subcontractor or supplier to the Buyer or any director, officer, employee or agent of the Buyer or any other person for whom the Buyer is responsible at law while the Buyer or any such Person is at the Seller's Plant.

19.3 Indemnification Conditions - The right of a Party ("**Indemnitee**") to be indemnified by the other Party ("**Indemnitor**") under any indemnity contained in this EPA in respect of a claim by a third Person is subject to the conditions that:

(a) the Indemnitee gives the Indemnitor prompt notice of such claim, the right to select and instruct counsel, and all reasonable cooperation and assistance, including the availability of documents and witnesses within the control of the Indemnitee, in the defence or settlement of the claim; and

(b) the Indemnitee does not compromise or settle the claim without the prior written consent of the Indemnitor.

20. GENERAL PROVISIONS

20.1 Electric Service to the Seller - If at any time the Buyer makes electric service available to the Seller's Plant, then that service will be provided under and in accordance with the Buyer's electric tariff applicable at the relevant time, and not under this EPA.

20.2 Independence - The Parties are independent contractors and nothing in this EPA or its performance creates a partnership, joint venture or agency relationship between the Parties.

20.3 Enurement - This EPA enures to the benefit of the Parties, their successors and their permitted assigns.

20.4 Notices - Any notice, consent, waiver, declaration, request for approval or other request, statement or bill (a "**notice**") that either Party may be required or may desire to give to the other Party under this EPA must be in writing addressed to the other Party at the address stated in subsection 20.4(c) or (d) and:

(a) may be delivered by hand or by a courier service during normal business hours on a Business Day, in which case the notice will be deemed to have been delivered on that Business Day;

(b) notices, other than notices under section 3.4, 4.2, or 7.2 or any of Articles 11, 13, 14, 15 or 16, may be sent by email during normal business hours on a Business Day, in which case provided that the Party delivering the notice obtains a confirmation of delivery, the notice will be deemed to have been delivered on that Business Day;

(c) subject to subsection 20.4(e), the address of the Buyer for notices is as set out in Appendix 9;

(d) subject to subsection 20.4(e), the address of the Seller for notices is as set out in Appendix 9 and the Buyer may, but is not required to (except as otherwise provided in a Lender Consent Agreement, if any) provide a copy of any such notice to the Facility Lender; and

(e) either Party may change its address or fax number for notices under this EPA by notice to the other Party.

20.5 Entire Agreement and Amendment - This EPA contains the entire agreement between the Parties with respect to the purchase and sale of Energy and supersedes all previous communications, understandings and agreements between the Parties with respect to the subject matter hereof including, without limitation, the Call for Tenders issued by the Buyer on 8 December 2005 and all Addenda, questions and answers and any other communications of any kind whatsoever by the Buyer in connection therewith or relating thereto. There are no representations, warranties, terms, conditions, undertakings or collateral agreements express, implied or statutory between the Parties other than as expressly set out in this EPA. This EPA may not be amended, except by an agreement in writing signed by both Parties.

20.6 No Waiver - Other than in respect of the specific matter or circumstance for which a waiver is given, and except as otherwise specified in this EPA, no failure by a Party to enforce, or require a strict observance and performance of, any of the terms of this EPA will constitute a waiver of those terms or affect or impair those terms or the right of a Party at any time to enforce those terms or to take advantage of any remedy that Party may have in respect of any other matter or circumstance.

20.7 Dispute Resolution - If any dispute arises under or in relation to this EPA, that dispute will be referred to and finally resolved by arbitration by a single arbitrator. The arbitration will be administered by the British Columbia International Commercial Arbitration Centre ("**BCICAC**") pursuant to its rules. The place of arbitration will be Vancouver, British Columbia. If at the time a dispute arises the BCICAC does not exist, the dispute will be finally settled by arbitration by a single arbitrator who, failing agreement of the parties, shall be appointed under the *Commercial Arbitration Act (British Columbia)* or under the *International Commercial Arbitration Act (British Columbia)*, as applicable, and the arbitrator shall conduct the arbitration in accordance with such rules as the Parties may agree in writing, or failing agreement, such rules as may be determined or adopted by the arbitrator. The decision of the arbitrator will be final and binding on the Parties. The arbitrator will have jurisdiction and power to make interim, partial or final awards ordering specific performance, injunction and any other equitable remedy. The Parties are entitled to seek interim measures of protection from the courts pending completion of any arbitration. All performance required under this EPA by the Parties and payments required under this EPA will continue during the dispute resolution proceedings contemplated by this section 20.7, provided that this section may not be interpreted or applied to delay or restrict the exercise of any right to suspend performance under or terminate this EPA pursuant to the express terms hereof. Any payments or reimbursements required by an arbitration award will be due as of the date determined in accordance with section 9.2 or, where section 9.2 is not applicable, as of the date determined in the award, and, without duplication with subsection 9.2(b), will bear interest at an annual rate equal to the Prime Rate plus 3%

compounded monthly, from the date such payment was due until the amount is paid. To the fullest extent permitted by law, the Parties shall maintain in confidence the fact that an arbitration has been commenced, all documents and information exchanged during the course of the arbitration proceeding, and the arbitrators' award, provided that each of the Parties shall be entitled to disclose such matters to its own officers, directors, shareholders and employees, its professional advisors and other representatives, and may make such disclosures in the course of any Proceedings required to pursue any legal right arising out of or in connection with the arbitration and may make such disclosures as are required by law or for regulatory purposes. Nothing in this EPA precludes either Party from bringing a Proceeding in any jurisdiction to enforce an arbitration award or any judgement enforcing an arbitration award, nor will the bringing of such Proceedings in any one or more jurisdictions preclude the bringing of enforcement Proceedings in any other jurisdiction. In connection with any court proceedings, each Party waives its respective rights to any jury trial.

20.8 Confidentiality

(a) Without limiting any other confidentiality agreement between the Parties, during the Term and for 5 years thereafter, the Buyer shall treat as confidential and will not cause or permit the publication, release or disclosure of any Confidential Information received by the Buyer from the Seller, except to the extent that publication, release or disclosure: (i) is expressly authorized under any section of this EPA; (ii) is necessary to enable the Buyer to fulfil its obligations under this EPA, including under section 3.3; (iii) is required by law or for regulatory purposes; (iv) is made with the prior consent of the Seller; or if (v) such information has entered the public domain other than through the actions of the Buyer. The Buyer may also disclose Confidential Information: (vi) to consultants and advisors to the Buyer and representatives of the Government of British Columbia who have a need to know the Confidential Information and who have been informed by the Buyer of the need to maintain the confidentiality of the Confidential Information disclosed to them; (vii) as may be necessary for the Buyer to adequately pursue or defend any legal or regulatory proceeding relating to the CFT or this EPA or any EPA awarded under the CFT process; and (viii) as otherwise set out in this EPA.

(b) The Seller acknowledges that the Buyer is subject to the *Freedom of Information and Protection of Privacy Act* (British Columbia) and agrees that the Buyer's non-disclosure obligations under this EPA are subject to the provisions of that legislation.

(c) The Parties confirm that Confidential Information constitutes commercial and financial information of the Seller, which has been supplied, or may be supplied, in confidence and the disclosure of which could reasonably be expected to harm significantly the competitive position and/or interfere significantly with the negotiating position of the Seller. Accordingly, the Parties confirm their intention that all Confidential Information disclosed by the Seller to the Buyer shall be deemed to be confidential and exempt from disclosure to third persons in accordance with section 21 of the *Freedom of Information and Protection of Privacy Act* (British Columbia), as amended from time to time.

20.9 Distribution Authority - This EPA shall be interpreted and applied as though the Distribution Authority were a third party, including for purposes of determining whether or not a Force Majeure has occurred.

20.10 Commodity Contract/Forward Contract - The Parties agree and intend that this EPA constitutes a commodity contract for the purposes of subsection (h) of the definition of "eligible financial contract" in section 65.1(8) of the *Bankruptcy and Insolvency Act* (Canada) and in Section 11.1(1) of the *Companies' Creditors Arrangement Act* (Canada) and that this EPA and the transactions contemplated under this EPA constitute a "forward contract" within the meaning of section 556 of the United States Bankruptcy Code and that the Parties are "forward contract merchants" within the meaning of the United States Bankruptcy Code.

20.11 Further Assurances - Each Party shall, upon the reasonable request of the other Party, do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required for the performance of this EPA.

20.12 Severability - Any provision of this EPA, which is illegal or unenforceable will be ineffective to the extent of the illegality or unenforceability without invalidating the remaining provisions of this EPA.

20.13 Counterparts - This EPA may be executed in counterparts, each of which is deemed to be an original document and all of which are deemed one and the same document.

IN WITNESS WHEREOF each Party by its duly authorized representative(s) has signed this EPA as of the date set out on page 1 of this EPA.

For ●

____
Authorized Representative

____
Print Name and Office

____
Date

For **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY:**

____
Authorized Representative

____
Print Name and Office

____
Date

APPENDIX 1

DEFINITIONS

References in an Appendix to a section or subsection mean a section or subsection of the EPA, and not an Appendix, unless otherwise stated. The following words and expressions wherever used in this EPA have the following meaning:

1. "**Affiliate**" means, with respect to the Seller, any Person directly or indirectly Controlled by, Controlling, or under common Control with, the Seller and with respect to the Buyer, any Person directly or indirectly Controlled by the Buyer and, if at any time the Buyer is not Controlled, directly or indirectly, by the Province of British Columbia, shall include any Person directly or indirectly Controlling, or under common Control with, the Buyer.

2. "**Annual Operating Plan**" means each plan delivered by the Seller to the Buyer under subsection 6.6(b) and all amendments to such plan in accordance with subsection 6.6(b).

3. "**Authorized Planned Outage**" means a Planned Outage that is scheduled in accordance with Good Utility Practice, complies with the requirements of section 6.4 and does not exceed the duration of the Planned Outage set out in the notice of the Planned Outage delivered by the Seller under section 6.4.

4. "**Bankrupt or Insolvent**" means, with respect to a Person:

   (a) the Person has started proceedings to be adjudicated a voluntary bankrupt or consented to the filing of a bankruptcy proceeding against it; or

   (b) the Person has filed a petition or similar proceeding seeking reorganization, arrangement or similar relief under any bankruptcy or insolvency law; or

   (c) a receiver, liquidator, trustee or assignee in bankruptcy has been appointed for the Person or the Person has consented to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy; or

   (d) the Person has voluntarily suspended the transaction of its usual business; or

   (e) a court has issued an order declaring the Person bankrupt or insolvent.

5. "**BCUC**" means the British Columbia Utilities Commission or any successor thereto.

6. "**BCUC Acceptance**" has the meaning given in section 3.1.

7. "**BC Clean Electricity**" means electricity that meets the requirements set out in the "BC Clean Electricity Guidelines" issued by the British Columbia Ministry of Energy, Mines and Petroleum Resources" dated 15 September, 2005, as amended at any time prior to the first anniversary of COD.

8. "**Bid Documents**" means the Tender and all documents and information provided by the Seller to the Buyer in connection with such Tender, whether concurrently with or after the date of submission of the Tender to the Buyer.

9. "**Business Day**" means any calendar day which is not a Saturday, Sunday or other day recognized as a statutory holiday in British Columbia.

10. "**Buyer**" means British Columbia Hydro and Power Authority and its successors and permitted assigns.

11. "**Buyer Termination Event**" means any one of the following:

    (a) the Seller is Bankrupt or Insolvent;

    (b) a Letter of Credit Failure has occurred and the Seller has failed to deliver a replacement Performance Security within 5 Business Days after the Letter of Credit Failure occurred;

    (c) the Seller has not, by the date that is the earlier of: (i) 60 days after the date of award of this EPA under the CFT; and (ii) 240 days after the date of issuance by the Transmission Authority to the Seller of the F2006 CFT Preliminary Interconnection Study Report, executed and delivered to, or caused to be executed and delivered to, the Transmission Authority a Combined Study Agreement for the Seller's Plant together with the applicable fee, in the form and amount prescribed by the Transmission Authority;

    (d) except where an amount has been disputed in the manner specified in subsection 9.1(b), an amount due and payable by the Seller to the Buyer under this EPA remains unpaid for 15 days after its due date and such default has not been cured within 15 days after the Buyer has given notice of the default to the Seller; or

    (e) the Seller is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by the Buyer to the Seller of the default the Seller has cured the default or, if the default cannot be cured within that 30 day period, the Seller demonstrates to the reasonable satisfaction of the Buyer that the Seller is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time. A "material default" includes any failure by the Seller to comply with subsection 6.3(f) or any of sections 6.8, 6.11 or 7.5, any Deliberate Breach by the Seller of its obligations under section 7.3, and any purported assignment of this EPA without the consent of the Buyer where such consent is required under Article 16. A "material default" does not include any failure, other than a failure resulting from a Deliberate Breach, to deliver the Monthly Firm Energy Amount in respect of which failure the Seller has paid any LDs owing under section 12.2.

12. "**CFT** " means the "F2006 Open Call for Power **-** Call for Tenders" issued by the Buyer on 8 December 2005, together with all Addenda thereto, and all other documents and forms referenced therein as forming part of the CFT.

13. "**COD**" or "Commercial Operation Date" means the time when the Seller's Plant achieves COD pursuant to section 5.2.

14. "**COD Certificate**" means a certificate in the form set out in Appendix 4 signed by a senior officer of the Seller.

15. **"COD Deadline"** means ______________________. ***[Note to Bidders: For bidders with a Guaranteed COD on or before 1 November 2009, the COD Deadline is 1 November 2009. For***

bidders with a Guaranteed COD after 1 November 2009, the COD Deadline is 1 November 2010]

16. "**COD Delay LDs**" means the LDs specified in section 12.1.

17. "**Combined Study Agreement**" means an agreement, in prescribed form, between the Seller and the Transmission Authority wherein the Seller contracts with the Transmission Authority for an interconnection impact study and interconnection facility study.

18. "**Compliance Units**" means any credit, offset, unit, allowance or other instrument that may be used to achieve compliance with emission limitation or intensity obligations as prescribed under Laws and Permits regulating GHG emissions from the Seller's Plant.

19. "**Confidential Information**" means: (i) information that is described as confidential information in any section of this EPA; and (ii) information disclosed by the Seller to the Buyer in the CFT process and that is described in the CFT as confidential.

20. "**Construction Insurance**" means all insurance generally accepted in the insurance industry as being required to construct a facility similar to the Seller's Plant, including course of construction insurance.

21. "**Control**" of any Person means: (i) with respect to any corporation or other Person having voting shares or the equivalent, the ownership or power to vote, directly or indirectly, shares, or the equivalent, representing 50% or more of the power to vote in the election of directors, managers or persons performing similar functions; (ii) ownership of 50% or more of the equity or beneficial interest in that Person; or (iii) the ability to direct the business and affairs of any Person by acting as a general partner, manager or otherwise.

22. "**Costs**" means brokerage fees, commissions and other similar transaction costs and expenses reasonably incurred or that would reasonably be expected to be incurred by the Seller in entering into new arrangements which replace this EPA, and legal fees, if any, incurred in connection with enforcing the Seller's rights under this EPA.

23. "**Deliberate Breach**" means:

    (a) any failure by the Seller to achieve COD by the earlier of: (i) Guaranteed COD plus 365 days plus all Force Majeure Days (not exceeding 365 Force Majeure Days); and (ii) the COD Deadline plus 180 days plus all Force Majeure Days (not exceeding 185 Force Majeure Days), resulting from any wilful or grossly negligent act or omission of the Seller;

    (b) any breach of or default under any provision of this EPA by the Seller resulting from any wilful or grossly negligent act or omission by the Seller;

    (c) a Buyer Termination Event constituting a repudiation of the EPA by the Seller; or

    (d) any sale or transfer by the Seller of Energy to any Person, other than the Buyer, except where such sale or transfer is expressly permitted under this EPA.

24. "**Development Costs**" means all costs reasonably incurred or committed by the Seller, after the date of issuance of the CFT, for the Project and all costs reasonably incurred, or that are

reasonably likely to be incurred by the Seller, after taking reasonable mitigation measures, to terminate all contractual commitments with respect to the Project and to otherwise cease development of the Project, but excluding any lost profits, loss of opportunity costs or damages and all other special, incidental, indirect or consequential losses.

25. "**Direct Assignment Costs**" means all costs of design, engineering, procurement, construction, installation and commissioning of Direct Assignment Facilities incurred by the Transmission Authority (in respect of the Transmission System) and/or the Distribution Authority (in respect of the Distribution System).

26. "**Direct Assignment Facilities**" means modifications or additions to transmission, or distribution, related facilities that are integrated with the Transmission System or the Distribution System, as the case may be, that are required to accommodate the interconnection of the Seller's Plant and are for the sole benefit of the Seller's Plant, as determined by the Transmission Authority (as to the Transmission System) or the Distribution Authority (as to the Distribution System).

27. "**Distribution Authority**" means the Person or Persons who is or are responsible for the planning, asset management, and operation of the Distribution System, in whole or in part, including an independent system operator.

28. "**Distribution System**" means the distribution, protection, control and communication facilities in British Columbia that are or may be used in connection with, or that otherwise relate to, the transmission of electrical energy at 35kV or less, and includes all additions and modifications thereto and repairs or replacements thereof.

29. "**EcoLogo^{M} Certification**" means certification pursuant to Environment Canada's Environmental Choice^{M} program confirming that the Seller's Plant and all or part of the Energy complies with the "Guideline on Renewable Low-Impact Electricity", as amended from time to time and is therefore entitled to the EcoLogo^{M} designation.

30. "**Effective Date**" means the date set out on page one hereof.

31. "**Eligible Energy**" means in each month after COD:

    (a) the amount of Metered Energy delivered by the Seller at the POI in that month, but excluding any portion of the Metered Energy that at any time exceeds 120% of the Plant Capacity; and

    (b) Energy that is deemed to be "Eligible Energy" in that month pursuant to section 7.9.

32. "**Energy**" means electric energy expressed in MWh generated by the Seller's Plant excluding Station Service.

33. "**Energy Source**" means the source of energy used to generate Energy at the Seller's Plant as specified in Appendix 5.

34. "**Escalated Bid Price**" has the meaning given in Appendix 3.

35. "**F2006 CFT Preliminary Interconnection Study Report**" means the report referenced in section 7 of Appendix 5.

36. "**Facilities Agreement**" means the agreement between the Seller and the Transmission Authority setting out the commercial terms and conditions applicable to the construction of the Direct Assignment Facilities and Network Upgrades as amended or replaced from time to time.

37. "**Facility Lender**" means any lender(s) providing any debt financing for the Project and any successors or assigns thereto.

38. "**Final Amount**" means an amount owing by either Party to the other Party pursuant to this EPA (including as a result of a breach of this EPA) where such amount is: (a) undisputed by the Party owing such amount; or (b) has been finally determined by an arbitration award pursuant to section 20.7 or by a court order and all rights of appeal in respect of such award or order have been exhausted or have expired.

39. "**Firm Energy**" has the meaning given in Appendix 3.

40. "**Force Majeure**" means, subject to the exclusions in section 11.2, any event or circumstance not within the control of the Party claiming Force Majeure and, to the extent not within that Party's control, includes:

    (a) acts of God, including wind, ice and other storms, lightning, floods, earthquakes, volcanic eruptions and landslides;

    (b) strikes, lockouts and other industrial disturbances, provided that settlement of strikes, lockouts and other labour disturbances will be wholly within the discretion of the Party involved;

    (c) epidemics, war (whether or not declared), blockades, acts of public enemies, acts of sabotage, civil insurrection, riots and civil disobedience;

    (d) acts or omissions of Governmental Authorities, including delays in regulatory process and orders of a regulatory authority or court of competent jurisdiction;

    (e) explosions and fires; and

    (f) notwithstanding subsection 11.2(f), an inability of the Seller to achieve COD solely as a result of a delay by the Transmission Authority in completion of Direct Assignment Facilities or Network Upgrades and such delay is not attributable to the Seller or the Seller's Plant, including any change to the point of interconnection with the Transmission System or other Project change made by the Seller under section 4.5,

    but does not include:

    (g) any refusal, failure or delay of any Governmental Authority in granting any Material Permit to the Seller, whether or not on terms and conditions that permit the Seller to perform its obligations under this EPA, except where such failure or delay is a result of an event described in paragraph (a), (b), (c) or (e) above.

41. "**Force Majeure Days**" means the number of days the Seller is delayed in achieving COD as a result of Force Majeure invoked by the Seller in accordance with Article 11.

42. “**Forced Outage**” means a partial or total interruption in the delivery of, or ability to deliver, Energy that is not a result of an Authorized Planned Outage or a Force Majeure.

43. “**Gains**” means an amount equal to the present value of the economic benefit (exclusive of Costs), if any, to the Seller resulting from the termination of this EPA, determined in a commercially reasonable manner.

44. “**GHG**” or “**Greenhouse Gas(es)**” means: (i) one or more of the following gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride; and (ii) any other gas that is identified as having significant global warming potential and is added, at any time before the expiry of the Term, to Schedule 1 to the *Canadian Environmental Protection Act, 1999* or to any other regulation(s) governing the emission of the gases noted in (i) from the Seller’s Plant.

45. “**Good Utility Practice**” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the WECC region.

46. “**Governmental Authorities**” means any federal, provincial, local or foreign governments or any of their boards or agencies, or any regulatory authority, other than the Buyer and the Seller and entities controlled by the Buyer or the Seller.

47. “**Green Attributes**” means:

    (a) all attributes associated with, or that may be derived from, the Energy and/or the Seller’s Plant having decreased environmental impacts, including any existing or future credit, allowance, “green” tag, ticket, certificate or other “green” marketing attribute or proprietary or contractual right, whether or not tradeable, resulting from the Energy during the Term;

    (b) any credit, reduction right, offset, allowance, allocated pollution right, certificate or other unit of any kind whatsoever, whether or not tradeable and any other proprietary or contractual right, whether or not tradeable, resulting from, or otherwise related to: (i) the actual or assumed reduction, displacement or offset of emissions at any location other than the Seller’s Plant as a result of the generation, purchase or sale of the Energy; or (ii) the reduction, removal, avoidance, sequestration or mitigation of emissions at or from the Seller’s Plant; and

    (c) all revenues, entitlements, benefits and other proceeds arising from or related to the foregoing.

48. “**GST**” means the goods and services tax imposed under the Excise Tax Act (Canada) as that Act may be amended or replaced from time to time.

49. “**Guaranteed COD**” means ______TO#1_________.

50. “**Interconnection**” means the facilities and procedures that permit the flow of electric power from the Seller’s Plant to the Transmission System and vice versa.

51. “**Interconnection Agreement**” means the agreement between the Seller and the Transmission Authority which provides for the implementation and operation of the Interconnection, as amended or replaced from time to time.

52. “**kV**” means kilovolts.

53. “**Laws**” means any and all statutes, laws (including common law), ordinances, rules, regulations, codes, orders, bylaws, policies, directions, standards, guidelines, protocols and other lawful requirements of any Governmental Authority.

54. “**LDs**” means liquidated damages payable by the Seller to the Buyer under Article 12.

55. “**Lender Consent Agreement**” means an agreement referred to in section 16.3.

56. “**Letter of Credit Failure**” means:

    (a) a failure to renew or substitute the Performance Security by no later than 60 days prior to the expiry thereof;

    (b) the issuer of the Performance Security fails to maintain a credit rating of at least the minimum rating specified in section 13.4;

    (c) the issuer of the Performance Security fails to comply with or perform its obligations under the Performance Security;

    (d) the issuer of the Performance Security disaffirms, disclaims, repudiates, terminates, rejects, in whole or in part, or challenges the validity of, the Performance Security; or

    (e) the Performance Security fails or ceases to be in full force and effect for purposes of this EPA (whether or not in accordance with its terms) prior to the date specified in Article 13 for return of the Performance Security to the Seller.

57. “**Long Term Operating Plan**” means the plan referred to in subsection 6.6(a) as amended by the Seller from time to time.

58. “**Losses**” means an amount equal to the present value of the economic loss (exclusive of Costs), if any, to the Seller resulting from the termination of this EPA, determined in a commercially reasonable manner.

59. “**Major Damage**” means damage where the cost to repair the damage exceeds the present value (using the Present Value Rate) of (a) the projected Energy deliveries from the Seller’s Plant for the remainder of the Term, multiplied by (b) the projected payments under this EPA for that Energy, (calculated on the basis that the Tier 2 Non-Firm Energy Price will be equal to the Tier 1 Non-Firm Energy Price), less a $/MWh amount representing the estimated operating and maintenance costs for the Seller’s Plant (including costs of the Energy Source).

60. “**Material Permits**” means all of the following if and as required for the Seller’s Plant:

    (a) environmental assessment certificate;

(b) air emissions permit;

(c) any permits, licenses or approvals required with respect to the discharge of any type of waste liquids from the Seller's Plant;

(d) water licence;

(e) zoning appropriate for the Seller's Plant;

(f) any subdivision approvals required to create the site on which the Seller's Plant is or will be located as a separate legal parcel;

(g) any permits or approvals required with respect to the storage of the Energy Source at the Seller's Plant; and

(h) any lease, license or occupation or similar agreement required with respect to the Seller's Plant including all access roads to the Seller's Plant,

on terms and conditions that permit the Seller to comply with its obligations under this EPA.

61. "**Metered Energy**" means Energy recorded by the Metering Equipment.

62. "**Metering Equipment**" means the metering equipment described in section 8.1.

63. "**Monthly Firm Energy Amount**" means the amount of Energy the Seller is required to deliver to the Buyer at the POI in each month of the Term after COD as set out in Appendix 2.

64. "**Monthly Firm Energy Delivery Rate**" means the Monthly Firm Energy Amount for the relevant month as set out in Appendix 2 divided by the number of hours in that month.

65. "**MW**" means megawatt.

66. "**MWh**" means megawatt-hour.

67. "**NERC**" means the North American Electric Reliability Council or a successor organization.

68. "**Network Upgrades**" means modifications or additions to transmission, or distribution, related facilities that are integrated with and support the overall Transmission System or Distribution System, as the case may be, that are required to accommodate the interconnection of the Seller's Plant to the system and to transmit the electricity from the Seller's Plant through the system to the Buyer's network loads, but which benefit all users of the system, as determined by the Transmission Authority (as to the Transmission System) or the Distribution Authority (as to the Distribution System).

69. "**Network Upgrade Costs**" means all costs incurred by the Transmission Authority (in respect of the Transmission System) and/or the Distribution Authority (in respect of the Distribution System) for the design, engineering, procurement, construction, installation and commissioning of Network Upgrades.

70. "**Outage**" means:

(a) in the case of the Seller's Plant, a partial or total interruption in the delivery of, or ability to deliver, Energy; and

(b) in the case of the Transmission System, a partial or total interruption in the transmission of, or ability to transmit, Energy from the Seller's Plant.

71. "**Party**" means: (i) the Buyer and its successors and permitted assigns; or (ii) the Seller and its successors and permitted assigns, and "Parties" means both the Buyer and the Seller and their respective successors and permitted assigns, provided that the Distribution Authority shall be deemed not to be a "Party", whether or not owned or operated by British Columbia Hydro and Power Authority.

72. "**Peak Demand Months**" means January, February, March, November and December.

73. "**Performance Security**" means a letter of credit in the form specified in section 13.4 in an amount equal to:

(a) prior to the first anniversary of COD, $60,000/MW multiplied by the Plant Capacity; or

(b) from and after the first anniversary of COD, $40,000/MW multiplied by the total of the Monthly Firm Energy Amounts set out in Appendix 2 divided by 8760.

74. "**Permits**" means permits, certificates, licences, and other approvals required for the design, construction, ownership, operation and maintenance of the Seller's Plant and the delivery of Eligible Energy at the POI, including all Material Permits.

75. "**Person**" means an individual, body corporate, firm, partnership, joint venture, trust, legal representative or other legal entity.

76. "**Planned Islanding Capability**" means the ability of a generator to electrically energize, in a safe, controlled and reliable manner, a portion of the Transmission System or Distribution System, including loads, that is separated from the rest of the Transmission System or Distribution System.

77. "**Planned Outage**" means an Outage for purposes of inspection and/or general overhaul of equipment in the Seller's Plant.

78. "**Plant Capacity**" means the electrical capacity of the Seller's Plant expressed in MW, determined as the nameplate capacity if expressed in MW, or as the nameplate capacity if expressed in MVA multiplied by a power factor of 0.95, as set out in Appendix 5, as amended in accordance with section 4.2.

79. "**POI**" or "**Point of Interconnection**" means the point at which the Seller's Plant interconnects with the Transmission System as more particularly defined in the Interconnection Agreement.

80. "**PPT**" means Pacific Prevailing Time, which means Pacific Daylight Time or Pacific Standard Time as applicable.

81. "**Pre-COD Energy**" means that amount of Metered Energy delivered by the Seller at the POI prior to COD including Test Energy, but excluding:

(a) any portion of the Metered Energy that at any time exceeds 120% of the Plant Capacity; and

(b) that portion of the Metered Energy that is sold to third parties in accordance with section 7.1.

82. "**Present Value Rate**" has the meaning given in subsection 15.5(k).

83. "**Prime Rate**" means the floating prime interest rate announced from time to time by the main branch of Bank of Montreal in Vancouver, or any successor thereto, expressed as an annual rate, as the reference rate it will use to determine rates of interest payable on Canadian dollar commercial loans made in Canada.

84. "**Proceeding**" has the meaning given in section 1.5.

85. "**Project**" means the financing, design, engineering, procurement, construction, commissioning, operation and maintenance of the Seller's Plant.

86. "**Project Assets**" means the Seller's Plant and all rights, property, assets, equipment, materials and contracts required to design, engineer, procure, construct, commission, operate and maintain the Seller's Plant, whether real or personal and whether tangible or intangible, including equipment and other warranties, Permits, supply and other contracts, the goodwill in and right to use the name by which the Seller's Plant is commonly known, the books, records and accounts with respect to the Seller's Plant, and all land tenure and land tenure agreements with respect to the Seller's Plant.

87. "**PST**" means British Columbia provincial social service or sales taxes and similar or replacement assessments, if any.

88. "**Seller**" means the Party so identified on page one of this EPA, and its successors and permitted assigns.

89. "**Seller Termination Event**" means:

(a) the Buyer is Bankrupt or Insolvent;

(b) except where an amount has been disputed in the manner specified in subsection 9.1(b), an amount due and payable by the Buyer to the Seller under this EPA remains unpaid for 15 days after its due date and such default has not been cured within 15 days after the Seller has given notice of the default to the Buyer; or

(c) the Buyer is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), and such default has not been cured within 30 days after the Seller has given notice of the default to the Buyer or, if the default cannot be cured within that 30 day period, the Buyer fails to demonstrate to the reasonable satisfaction of the Seller that the Buyer is working diligently and expeditiously to cure the default or the default is not cured within a further reasonable period of time.

90. **“Seller’s Plant”** means the Seller’s plant described in Appendix 5 and all facilities and equipment required to construct, operate and maintain the plant described in Appendix 5 and to interconnect that plant to the Transmission System.

91. “**Station Service**” means electricity required to service the Seller’s Plant, including electricity required for fuel processing.

92. “**Tender**” means the Tender submitted by the Seller pursuant to the CFT.

93. “**Term**” has the meaning given in section 2.1.

94. “**Termination Payment**” means the amount payable by the Seller to the Buyer or the amount payable by the Buyer to the Seller pursuant to section 15.4 or section 15.5, as the case may be.

95. “**Test Energy**” means Metered Energy delivered at the POI during any successful test pursuant to subsection 5.2(b), but excluding all Metered Energy that at any time exceeds 120% of the Plant Capacity.

96. “**Transmission Authority**” means the British Columbia Transmission Corporation or any successor thereto.

97. “**Transmission System**” means the transmission, substation, protection, control and communication facilities: (i) owned by the Buyer or by the Transmission Authority; and (ii) operated by the Transmission Authority in British Columbia, and includes all additions and modifications thereto and repairs or replacements thereof.

98. “**UCA**” means the *Utilities Commission Act* (British Columbia).

99. “**WECC**” means the Western Electricity Coordinating Council or any successor organization of which the Buyer is a member.

APPENDIX 2

ENERGY PROFILE

[To be inserted from the Seller's Tender]

*For leap years, the Monthly Firm Energy Amount for the month of February will be multiplied by 29/28.

[Note to Bidders: For Bidders that elect to tender an Hourly Firm Energy Profile, the table set out in Section 11 of the CFT in the bullet titled "Energy Profile" will be inserted in Appendix 2 as Part 2 of Appendix 2.]

APPENDIX 3

ENERGY PRICE

1. Definitions and Interpretation

1.1 **Definitions -** In this Appendix 3 or elsewhere in the EPA, the following words and expressions have the following meanings:

(a) "**BPP**" or "**Bid Price Percentage**" means __BP#5___%, which is the percentage of the Initial Period Bid Price and the Remainder Period Bid Price that is subject to escalation pursuant to section 3.3 of this Appendix.

(b) "**CPI**" means the Consumer Price Index for Canada, All Items (Not Seasonally Adjusted) as published by Statistics Canada, adjusted or replaced in accordance with subsection 1.2(d) of this Appendix.

(c) "**Discount Amount**" means $8.00/MWh.

(d) "**Escalated Bid Price**" means:

(i) for the period from COD to the hour ending at 24:00 PPT on the day immediately prior to the first day of the month following the _BP#2____ anniversary of COD, the Initial Period Bid Price, as adjusted pursuant to section 3.3 of this Appendix; and

(ii) for the period from the hour commencing at 00:00 PPT on the first day of the month following the __BP#2___ anniversary of COD for the remainder of the Term, the Remainder Period Bid Price, as adjusted pursuant to section 3.3 of this Appendix.

[Note to Bidders: If there is only one Bid Price for the Term, the above section will be revised to read ""Escalated Bid Price" means the Bid Price $__BP#4_/MWh as adjusted pursuant to section 3.3 of this Appendix."]

(e) "**Escalated Discount Amount**" means the Discount Amount as adjusted pursuant to section 3.3 of this Appendix.

(f) "**Firm Energy**" means in each month of the Term after COD, all Eligible Energy in that month not exceeding the Monthly Firm Energy Amount for that month, but excluding any Eligible Energy delivered after the start time and prior to the end time for an Authorized Planned Outage as set out in the notice with respect to the Authorized Planned Outage under section 6.4 and all such Eligible Energy will be considered Non-Firm Energy.

(g) "**Firm Energy Price**" means the Escalated Bid Price as adjusted pursuant to section 3.4 of this Appendix.

(h) "**HLH**" or "**Heavy Load Hours**" means the hours commencing at 06:00 PPT and ending at 22:00 PPT Monday through Saturday inclusive but excluding British Columbia statutory holidays.

(i) "**Initial Period Bid Price**" means $____BP#3__________________/ MWh.

[Note to Bidders: If there is only one Bid Price for the Term, the above definition will be revised to read "Bid Price means $ BP#4 /MWh".]

(j) "**LLH**" or "**Light Load Hours**" means all hours other than Heavy Load Hours.

(k) "**Mid-C**" means the Mid-Columbia electricity region.

(l) "**Non-Firm Energy**" means in each month of the Term after COD all Eligible Energy in that month in excess of the Monthly Firm Energy Amount for that month and all Eligible Energy deemed to be Non-Firm Energy pursuant to subsection 1.1(f) of this Appendix.

(m) "**Non-Firm Energy Discount**" means the Escalated Discount Amount as adjusted pursuant to section 3.4 of this Appendix.

(n) "**Off-Peak Index**" means the Dow Jones Mid-C daily firm Off-Peak Index.

(o) "**Remainder Period Bid Price**" means $__BP#3_/ MWh.

[Note to Bidders: If there is only one Bid Price for the Term, the above definition will be deleted.]

(p) "**Tier 1 Non-Firm Energy**" means in each month during the Term after COD all Non-Firm Energy not exceeding an amount equal to the Monthly Firm Energy Amount for the month.

(q) "**Tier 1 Non-Firm Energy Price**" means the Firm Energy Price minus the Non-Firm Energy Discount.

(r) "**Tier 2 Non-Firm Energy**" means in each month during the Term after COD all Non-Firm Energy in excess of the Tier 1 Non-Firm Energy for that month.

(s) "**Tier 2 Non-Firm Energy Price**" means the lesser of:

(i) the Tier 1 Non-Firm Energy Price; and

(ii) an amount equal to 70% of the average of the daily non-firm Mid-C Off-Peak Index prices in the applicable month. Amounts quoted in U.S. dollars will be converted to Canadian dollars using the average of the Bank of Canada daily "noon rates" for that month.

1.2 **Interpretation -** All payments will be calculated applying the following principles:

(a) all payment calculations will be rounded to the nearest cent;

(b) Energy will be expressed in MWh rounded to two decimal places;

(c) any escalators or percentages will be expressed as a percentage and will be rounded to four decimal places (i.e. 0.0000%); and

(d) if Statistics Canada (or the then recognized statistical branch of the Canadian Government):

(i) computes, at any time after the Effective Date, the CPI on a basis different to that employed at the Effective Date, then the CPI will be converted using the appropriate formula recommended by Statistics Canada (or the then recognized statistical branch of the Canadian Government);

(ii) at any time ceases to publish or provide the CPI, then the provisions of section 1.9 of this EPA will apply;

(iii) has not published the CPI for a relevant period at the time the Seller is required to provide the Buyer with an invoice, the Seller shall prepare the invoice based on the CPI in effect at the time the invoice is issued and when the CPI for the relevant period is published, the Seller shall recalculate the invoice amounts in the next succeeding invoice and shall include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation; or

(iv) recalculates the CPI within 36 months after an invoice affected by that CPI calculation has been issued, then the Seller shall recalculate the invoice amounts for the relevant period in the next succeeding invoice and shall include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation.

2. Pre-COD Energy

2.1 No price is payable by the Buyer for Energy, if any, delivered to the Buyer before COD, except as set out in section 2.2 of this Appendix.

2.2 The price payable by the Buyer for Test Energy in respect of which the Seller has not given a notice under section 7.1 is $25.00/MWh. If the Seller's Plant does not satisfy the requirements of section 5.2, no price is payable by the Buyer for any Energy generated during the period specified in subsection 5.2(b).

3. Post-COD Energy

3.1 **Firm Energy -** The price payable by the Buyer for each MWh of Firm Energy is the Firm Energy Price.

3.2 **Non-Firm Energy -** The price payable by the Buyer for each MWh of Tier 1 Non-Firm Energy is the Tier 1 Non-Firm Energy Price. The price payable by the Buyer for each MWh of Tier 2 Non-Firm Energy is the Tier 2 Non-Firm Energy Price.

3.3 **CPI Adjustment -** The Initial Period Bid Price ("**IPBP**"), the Remainder Period Bid Price ("**RPBP**") and the Discount Amount ("**DA**") will be adjusted effective as of January 1 in each year after the Effective Date in accordance with the following applicable formula:

$$IPBP_n = IPBP_{\text{January 1 2006}} * [(BPP * CPI_{\text{January 1 n}}/CPI_{\text{January 1 2006}}) + (1 - BPP)]$$

$$RPBP_n = RPBP_{\text{January 1 2006}} * [(BPP * CPI_{\text{January 1 n}}/CPI_{\text{January 1 2006}}) + (1 - BPP)]$$

$$DA_n = DA_{\text{January 1 2006}} * CPI_{\text{January 1 n}}/CPI_{\text{January 1 2006}}$$

Where:

n = the year for which the relevant calculation is being conducted

$CPI_{January\ 1\ n}$ = the CPI for December in the year immediately prior to the year for which the relevant calculation is being conducted.

3.4 **Delivery Time Adjustment -** For each hour during the Term, the Escalated Bid Price and the Escalated Discount Amount will be adjusted to an amount (expressed in \$/MWh) equal to the percentage of the Escalated Bid Price or the Escalated Discount Amount, as applicable, expressed in the following table:

Month	Escalated Bid Price Adjustment		Escalated Discount Amount Adjustment	
	HLH	LLH	HLH	LLH
January	113%	97%	88%	103%
February	109%	102%	92%	98%
March	105%	100%	95%	100%
April	103%	88%	97%	114%
May	104%	73%	96%	137%
June	104%	71%	96%	141%
July	104%	77%	96%	130%
August	104%	97%	96%	103%
September	105%	98%	95%	102%
October	103%	89%	97%	112%
November	106%	104%	94%	96%
December	117%	101%	85%	99%

3.5 **Calculation of Firm and Non-Firm Energy Amounts -** If in any month after COD the Eligible Energy for the month exceeds the Monthly Firm Energy Amount for that month, the amount of Firm Energy and Non-Firm Energy delivered during Heavy Load Hours is determined by multiplying the total Firm Energy or Non-Firm Energy amount for that month, as applicable, by the proportion of total Eligible Energy delivered during Heavy Load Hours in that month. The remainder of the Energy in each case will be deemed to have been delivered in Light Load Hours. The following provides an illustration of the application of this section:

	HLH	LLH	Total
Tendered Firm Energy	N/A	N/A	20
Total Eligible Energy delivered *as a % of total*	30 *60%*	20 *40%*	50 *100%*
Firm Energy delivered	12	8	20
Tier 1 Non-Firm Energy delivered	12	8	20
Tier 2 Non-Firm Energy delivered	6	4	10

3.6 **Third Person Sales -** Where the Seller has sold Energy to a third Person in accordance with section 7.5, there shall be deducted from the amount otherwise payable by the Buyer to the Seller in respect of the Energy that is deemed to be Eligible Energy pursuant to section 7.9 an amount equal to any revenue received by the Seller from the third Person for that Energy.

4. Property Tax Flow Through

In each year during the Term after COD, provided that the taxes payable in respect of the Seller's Plant in that year exceed the taxes payable in respect of the Seller's Plant during the year in which COD occurred determined in accordance with the following formula (where the definitions applicable to such formula have the meaning given below):

$$[(TRl_n * AVl_n) + (TRi_n * AVi_n)] > [(TRl_{COD} * AVl_{COD}) + (TRi_{COD} * AVi_{COD})],$$

then, the Buyer shall pay the Seller an amount determined in accordance with the following formula:

Payment Amount = (the greater of (i) zero and (ii) the amount determined in accordance with the following formula):

$$\{[(TRl_n - TRl_{COD}) * AVl_n] + [(TRi_n - TRi_{COD}) * AVi_n]\} * 0.5$$

Where:

TRl = Tax rates for the land on which the Seller's Plant is located

TRi = Tax rates for the improvements

AVl = Assessed value of the land on which the Seller's Plant is located

AVi = Assessed value of the improvements

n = the year in which the tax invoice is received by the Seller

"tax" means any ad valorem tax imposed by any Governmental Authority with respect to the Seller's Plant, including the associated land, as shown on the annual property tax notice for the Seller's Plant.

"improvements" means those improvements forming part of the Seller's Plant at COD.

Notwithstanding the foregoing, the Buyer will only be required to pay a portion of the amount determined in accordance with the foregoing formula based on the portion of the year following COD or the portion of the year prior to termination, as applicable. In addition, the amount payable by the Buyer will be reduced on a proportionate basis for each day in which the Seller does not deliver Eligible Energy to the Buyer, except where the Seller is excused from its delivery obligation under subsection 7.8(a).

The Seller shall have the burden of proving which improvements formed part of the Seller's Plant at COD. In each year during the Term after COD, within 60 days after receipt of the tax statement for the Seller's Plant, the Seller shall provide an invoice to the Buyer for any amount owing by the Buyer to the Seller pursuant to this section, together with all information and documents reasonably required to support the invoice. The Buyer shall pay any amount owing by the Buyer to the Seller under this section within 60 days after receipt from the Seller of an invoice in accordance with this section.

5. No Further Payment

5.1 The amounts payable by the Buyer as specified in this Appendix 3 are the full and complete payment and consideration payable by the Buyer for all Eligible Energy under this EPA.

APPENDIX 4

COD CERTIFICATE

_____________ PROJECT

TO: British Columbia Hydro and Power Authority (the "**Buyer**")

RE: Electricity Purchase Agreement ("**EPA**") made as of ●, 2006 between the Buyer and ● (the "**Seller**") for ________ Project

I, *[name of senior officer]*, in my capacity as *[title of senior officer]* of the Seller, and not in my personal capacity, certify on behalf of the Seller that:

1. **Defined Terms -** Words and phrases having initial capitalized letters in this Certificate have the meanings given in the EPA.

2. **COD Requirements -** The Seller has satisfied the requirements for COD as set out in section 5.2 of the EPA. Attached to this Certificate is all evidence required to demonstrate that the Seller has satisfied all such requirements.

3. **No Material Default -** No event which constitutes a Buyer Termination Event under subsection (a) or (e) of the definition of "Buyer Termination Event" in Appendix 1 to the EPA has occurred. The Seller has obtained all Material Permits and is not in material default under any Material Permit (and all Material Permits are in full force and effect), any tenure agreement for the site on which the Seller's Plant is located, the Interconnection Agreement or the Facilities Agreement.

Dated this _____ day of _________________, 200____.

____

[name of senior officer]

[title of senior officer]

[Attach to the Certificate in tabbed format all documents and evidence required under section 5.2 of the EPA. Where documents have previously been provided to the Buyer, so indicate and attach a copy of the letter transmitting such documents to the Buyer.]

APPENDIX 5

SELLER'S PLANT DESCRIPTION

[Note to Bidders: To be inserted from the Seller's Tender - See CFT Form #2]

APPENDIX 6

SAMPLE FORM STANDBY LETTER OF CREDIT

[Issuing Bank Name & Address]

Date of Issue: [Date]

Irrevocable Standby Letter of Credit

[*Number*]

Applicant:

[*Seller Name and Address]*

Beneficiary:

British Columbia Hydro and Power Authority

At the request and for the account of the Applicant, we hereby establish in favour of the Beneficiary our irrevocable standby Letter Of Credit No. ([*Number*]) (hereinafter called the "**Letter of Credit**") for an amount not exceeding [*Currency and Amount both in letters and numbers*].

We, [*Bank Name and Address*] hereby unconditionally and irrevocably undertake and bind ourselves, and our successors and assigns, to pay you immediately, the sum, which you claim upon receipt of the following documents:

(1) your signed written demand specifying the amount claimed (not exceeding [*Dollar Amount*]), and certifying that such amount is due to you by the Applicant under the terms of an Electricity Purchase Agreement between you and the Applicant made as of [*Date*]; and

(2) this original Letter of Credit must be presented with your demand for payment for endorsement purposes.

Partial drawings are allowed. The amount of this Letter of Credit shall be automatically reduced by the amount of any drawing paid hereunder.

This Letter of Credit takes effect from the date of issue set forth above, and shall remain valid until [ ] However, it is a condition of this Letter of Credit that it will be automatically extended without notice for a further one year period from the present or any future expiry date unless at least ninety (90) days prior to such expiry date we notify you in writing by courier or registered mail at your address above that we elect not to consider this Letter of Credit to be extended for any additional period.

This Letter of Credit is subject to the Uniform Customs and Practice for Documentary Credits (1993 Revision), International Chamber of Commerce, (Publication No. 500). This Letter of Credit is governed by the laws applicable in the Province of British Columbia. The parties hereby irrevocably attorn to the non-exclusive jurisdiction of the courts of British Columbia. The number of this Letter of Credit must be quoted on all documents required hereby. Notwithstanding Article 17 of said publication, if this Letter of

Credit expires during an interruption of business as described in Article 17, we agree to effect payment if this Letter of Credit is drawn within 15 days after resumption of normal business.

______________________________	______________________________
Authorized Signing Officer	Authorized Signing Officer
[Bank Name]	[Bank Name]

APPENDIX 7

SAMPLE FORM LENDER CONSENT AGREEMENT

(See section 16.3)

THIS AGREEMENT is made as of _______________ ____, 200_,

AMONG:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a corporation continued under the *Hydro and Power Authority Act*, R.S.B.C. 1996, c. 212, having its head office at 333 Dunsmuir Street, Vancouver, British Columbia, V6B 5R3,

(the "**Buyer**")

AND:

[COMPANY], a company under the laws of _______________having an address at ____,

(the **"Company")**

AND:

[LENDER], a __________________ under the laws of _______________having an address at ____,

(the "**Lender**").

WHEREAS:

A. The Buyer and the Company entered into an Electricity Purchase Agreement made as of _____________________ (as amended from time to time, the "EPA");

B. The Company has obtained certain credit facilities (the "Credit") from the Lender for the purposes of financing the design, construction, operation and maintenance of the Seller's Plant (as defined in the EPA);

C. To secure the due payment of all principal, interest (including interest on overdue interest), premium (if any) and other amounts payable in respect of the Credit and the due performance of all other obligations of the Company under the Credit, the Company has granted certain security to and in favour of the Lender, including an assignment of the right, title and interest of the Company under the EPA and security on the Seller's Plant (collectively, the "Lender Security"); and

D. The Lender has requested the Buyer to enter into this Agreement confirming certain matters.

NOW THEREFORE THIS AGREEMENT WITNESSES that in consideration of the premises and of the sum of $10 and other good and valuable consideration now paid by each of the Company and the Lender to the Buyer (the receipt and sufficiency of which are hereby acknowledged by the Buyer), the parties covenant and agree that:

1. Additional Definitions: In this Agreement, including the recitals:

   (a) "**Assumption Notice**" means a notice given by the Lender to the Buyer pursuant to subsection 6.1(a) of this Agreement;

   (b) "**Default or Termination Notice**" means a notice given to the Company by the Buyer under the EPA that, with or without the lapse of time, entitles, or will entitle, the Buyer to terminate the EPA, subject to rights, if any, of the Company to cure the default or other circumstance in respect of which the notice is given;

   (c) "**Receiver**" means a receiver, manager or receiver-manager appointed or designated by, or on the initiative of, the Lender; and

   (d) words and phrases defined in the EPA, and not otherwise defined herein, when used herein have the meanings given in the EPA.

2. **EPA Amendments**: The Buyer and the Company acknowledge and agree that the EPA is in full force and effect, and that the EPA, as originally executed, has been amended only by the documents attached hereto as Schedule A.

3. **Buyer Confirmations Concerning the EPA**: The Buyer confirms to the Lender that:

   (a) the EPA has been duly authorized, executed and delivered by the Buyer;

   (b) the Buyer has not received any notice of assignment by the Company of all or any part of their right, title and interest in and to the EPA, except to the Lender;

   (c) the Buyer has not given any Default or Termination Notice;

   (d) the Buyer is not aware of any default or other circumstance that would entitle the Buyer to give a Default or Termination Notice, provided however that the Buyer has not undertaken any investigation or due diligence in respect of this confirmation; and

   (e) the Buyer shall not enter into any agreement with the Company to materially amend the EPA, or enter into any agreement with the Company to terminate the EPA, without giving the Lender not less than 30 days' prior written notice.

4. **Assignment of EPA to Lender**:

4.1 *Buyer Acknowledgement:* The Buyer acknowledges receipt of notice of, and consents to, the assignment by the Company to the Lender of all the right, title and interest of the Company in and to the EPA made pursuant to and in accordance with the Lender Security.

4.2 *Lender Acknowledgement:* The Lender acknowledges that:

   (a) it has received a copy of the EPA; and

(b) the assignment by the Company to the Lender of the EPA pursuant to the Lender Security is subject in all respects to the terms and conditions of the EPA and this Agreement.

4.3 *Confidentiality:* The Lender covenants and agrees with the Buyer to be bound by the provisions of section 20.8 of the EPA regarding confidentiality, as if an original signatory thereto.

4.4 *Company Representation:* The Company represents and warrants to the Buyer that the Lender is the only person, other than the Buyer, to whom it has granted a security interest in the EPA or the Seller's Plant.

5. **EPA Notices**: The Buyer covenants and agrees with the Lender that, except as hereinafter otherwise permitted, the Buyer:

(a) shall give the Lender a copy of any Default or Termination Notice concurrently with, or promptly after, any such notice is given to the Company;

(b) shall not exercise any right it may have to terminate the EPA or any right pursuant to Article 14 of the EPA until the later of: (i) the date that is 45 days after the date on which the Buyer delivered to the Lender a copy of the Default or Termination Notice entitling the Buyer to terminate or exercise any right pursuant to Article 14 of the EPA; and (ii) the date on which the Buyer is entitled to terminate or exercise any right pursuant to Article 14 of the EPA;

(c) shall not, provided that there is no other Buyer Termination Event under the EPA, terminate the EPA based on the Bankruptcy or Insolvency of the Seller if the Lender is promptly and diligently prosecuting to completion enforcement proceedings under the Lender Security until 30 days after the expiry of any court ordered period restricting the termination of the EPA; and

(d) shall not exercise any right it may have under section 9.5 of the EPA to deduct any amounts owing by the Seller to the Buyer under the EPA from amounts owing by the Buyer to the Seller under the EPA until the date that is 15 days after the date the Buyer provides the Lender with a copy of the notice delivered by the Buyer to the Seller under section 9.5 of the EPA.

Nothing in this Agreement prevents or restricts: (i) the exercise by the Buyer of any other right or remedy that it may be entitled to exercise under or in relation to the EPA; or (ii) the right of the Lender to cure, or cause the cure of, any default of the Company under the EPA that would be curable by the Company, whether or not an Assumption Notice is given.

6. **Realization by Lender**:

6.1 *Assumption Notice and/or Sale:* If the Company has defaulted under the Credit or the Lender Security and the Lender has elected to take possession of the Seller's Plant, either by a Receiver or in any other way, pursuant to the Security, the Lender shall either:

(a) give the Buyer written notice (an "**Assumption Notice**") stating that the Lender is assuming the EPA, whereupon:

(i) the Lender shall be entitled to all the rights and benefits, and shall have assumed, and shall perform and discharge, all the obligations and liabilities, of the

Company under the EPA, and the Lender shall be a party to, and bound by, the EPA as if an original signatory thereto in the place and stead of the Company;

(ii) notwithstanding subparagraph (i), the Lender shall not be liable to the Buyer for defaults of the Company occurring before the Assumption Notice is given, except to the extent that such defaults continue thereafter; provided however that the Buyer may at any time before or after such notice is given exercise any rights of set-off in respect of any such prior default under or in relation to the EPA which the Buyer would otherwise be entitled to exercise; or

(b) give written notice to the Buyer that the Lender wishes to cause the Company to assign all of the Company's right, title and interest in and to the EPA and the Seller's Plant to a third person or persons, subject however to the Company and the assignee complying with all provisions of the EPA relative to such assignment.

The Buyer agrees that if the Lender enters the Seller's Plant for the purpose of viewing or examining the state of repair, condition or operation thereof such shall not constitute taking possession thereof.

6.2 *Lender Liability and Release:* The Lender assumes no liability to the Buyer under the EPA unless and until the Lender gives an Assumption Notice. Thereafter, if the Lender completes an assignment to a third person or persons pursuant to and in accordance with the applicable provisions of the EPA, the Lender shall be released from all liability and obligations of the Company to the Buyer under the EPA accruing from and after completion of that assignment.

6.3 *Company not Released:* Nothing in this Agreement, and neither the giving of an Assumption Notice, nor any assignment pursuant to subsection 6.1(b) of this Agreement releases the Company from its obligations and liabilities to the Buyer under and in relation to the EPA.

6.4 *Receiver Included:* References in this section 6 to the Lender include a Receiver.

7. **<u>Notices</u>**: Any notice required or permitted to be given under this Agreement must be in writing and may be given by personal delivery, or by transmittal by facsimile, addressed to the respective parties as follows:

(a) Buyer at:

British Columbia Hydro and Power Authority
____
____
Attention: ________________________
Facsimile No.: ________________________

(b) **[Company]** at:

____
____
Attention: ________________________
Facsimile No.: ________________________

(c) **[Lender]** at:

____
____
Attention: ________________________
Facsimile No.: ________________________

Notices given by facsimile shall be deemed to be received on the business day next following the date of transmission.

8. **Choice of Law**: This Agreement is governed by British Columbia law, and the laws of Canada applicable therein.

9. **Jurisdiction**: Each party to this Agreement attorns irrevocably and unconditionally to the courts of the Province of British Columbia, and to courts to which appeals therefrom may be taken, in connection with any action, suit or proceeding commenced under or in relation to this Agreement. Notwithstanding the foregoing, the Lender acknowledges that upon an Assumption Notice being given, the Lender will become party to, and bound by, the agreements to arbitrate contained in section 20.7 of the EPA.

10. **Termination**: This Agreement, and all rights and liabilities among the parties hereunder shall terminate upon the full and final discharge of all of the Lender Security. The Lender shall give the Buyer prompt notice of the full and final discharge of all of the Lender Security.

11. **Amendment**: This Agreement may be amended only by an instrument in writing signed by each of the parties hereto.

12. **Enurement**: This Agreement enures to the benefit of, and is binding upon, the parties hereto, and their respective successors and permitted assigns.

13. **Counterparts**: This Agreement may be executed by facsimile and in any number of counterparts, each of which is deemed an original, and all of which together constitute one and the same document.

14. **Effective Date**: This Agreement is not binding upon any party unless and until executed and delivered by all parties, whereupon this Agreement will take effect as of the day first above written.

IN WITNESS WHEREOF each of the parties have duly executed this Agreement as of the day and year first above written.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY	**[COMPANY]**
By:______________________________ (Signature)	By:______________________________ (Signature)
Name: ____________________________	Name: ____________________________
Title: ____________________________	Title: ____________________________

[LENDER]

By: ___________________________________
(Signature)

Name: _________________________________

Title: __________________________________

APPENDIX 8

SAMPLE FORM DEVELOPMENT PROGRESS REPORT

BC Hydro Quarterly Development Report
For the quarter ending: _______________ Report Number:________
Project Name: ____

Tasks:	**Percentage of Completion**					**Comments**
	5%	25%	50%	75%	100%	
Permitting:						
Water Licence ***[Note to Bidders: This section will be expanded in the Awarded EPA to contain a list of Permits relevant to the Bidder's Project based on the information in the Bidder's Project Submission.]***						
Zoning Approval						
Subdivision Approval						
Leave to Construct						
Other Permits						
Financing:						
Construction						
Project Equity						
Long Term Financing						
Project Design:						
Preliminary						
Final						
Interconnection:						
Studies (Please describe the status of each interconnection study)						
Construction						
Major Equipment:						
Ordering						
Delivery						
Installation						
Construction:						
Road						
Powerhouse						
Other						

Key Project Tasks:	Target	Actual
Permitting Complete		
Financing Complete		
Interconnection/Facilities		

Agreements Signed		
Major Equipment Ordered		
Commence Construction		
Begin Commissioning		

COD:

Current Estimate: ___________________________

Prepared by: ____________________________________

Submitted by: ____________________________________

APPENDIX 9

ADDRESSES FOR DELIVERY OF NOTICES

Subject to subsection 20.4(e), the address for each of the Parties for notices is as follows:

Buyer: BC Hydro	Seller:
All Notices (Except as set out below)	
To: Manager, Contract Management Address: 333 Dunsmuir Street, 10th floor Vancouver B.C. V6B 5R3 Attention: (name to be inserted in Awarded EPA) Email: IPP.Contract@bchydro.com	To: Address: Email:
Development Reports	
To: Manager, Contract Management Address: 333 Dunsmuir Street, 10th floor Vancouver B.C. V6B 5R3 Attention: (name to be inserted in Awarded EPA) Email: IPP.Contract@bchydro.com	N/A
Planned Outages, Operating Plans, Notice of Outages, Energy Schedules	
To: Resource Coordinator, Plant Operations Group, Generation Address: 6911 Southpoint Drive, E15 Burnaby , B. C. V3N 4X8 Attention: (name to be inserted in Awarded EPA) Email: (to be inserted in Awarded EPA) Copy to: Contract Management, as per all Notices address	To: Address: Email:
GHG Compliance Reports	
To: Triple Bottom Line Strategy Address: 333 Dunsmuir Street, 9th floor Vancouver, B.C. V6B 5R3 Attention: (name to be inserted in Awarded EPA) Email: (to be inserted in Awarded EPA) Copy to: Contract Management, as per all Notices address	To: Address: Email:

Buyer: BC Hydro	Seller:
Invoices and Statements	
To: IPP Invoicing Address: 333 Dunsmuir Street, 16th floor Vancouver, B.C. V6B 5R3 Attention: (name to be inserted in Awarded EPA) Email: IPP.Invoicing@bchydro.com	To: Address: Email:
Performance Security	
To: Distribution Line of Business, Finance Address: 6911 Southpoint Drive, E16 Burnaby, B.C. V3N 4X8 Attention: (name to be inserted in Awarded EPA) Copy to: Contract Management, as per all Notices address	To: Address: Email:
Insurance	
To: Manager, Contract Management Address: 333 Dunsmuir Street, 10th floor Vancouver B.C. V6B 5R3 Attention: (name to be inserted in Awarded EPA) Email: IPP.Contract@bchydro.com	To: Address: Email:

If the Seller is a joint venture, general partnership or limited partnership, a notice given in accordance with the foregoing provisions is deemed to have been given to the Seller and to each joint venturer and/or partner as applicable.

APPENDIX 10

SPECIAL TERMS AND CONDITIONS

PART A - HOURLY FIRM PROJECTS

This Part applies to Sellers that submitted an Hourly Firm Energy Profile in the CFT process.

1. Subsection 5.2(b) is deleted and replaced with the following:

    (b) the Seller's Plant has generated Energy in compliance with all Material Permits for 72 continuous hours in an amount not less than the greater of: (i) 95% of the Hourly Firm Energy Amount for each such hour; and (ii) 20% of the Plant Capacity multiplied by 1 hour;

2. Section 5.6 is amended by deleting the words "Monthly Firm Energy Amount" wherever those words appear in that section and replacing them with "Hourly Firm Energy Amount".

3. Subsection 6.4(a) is deleted and replaced with the following:

    "(a) ensure that no Planned Outage occurs during the Peak Demand Months except with the consent of the Buyer, which consent will not be unreasonably withheld where the Seller is required to conduct a Planned Outage during Peak Demand Months by reason of Law, Permits or contracts and where, in the case of a contractual requirement, the Seller has used commercially reasonable efforts to avoid inclusion of such requirement in the contract. Where the Seller is authorized under this section to conduct a Planned Outage or Planned Outages during Peak Demand Months, the total number of hours of such Planned Outages in any November to March period shall not exceed 180;"

4. Subsection 6.6(f) is deleted and replaced with the following:

    "(f) **Energy Schedules -** After COD on each Thursday by 12:00 PPT, the Seller shall deliver to the Buyer a schedule of the expected deliveries of Eligible Energy in each hour of each day for the next succeeding week commencing at 00:00 PPT on Monday, provided that such schedules are provided for planning purposes only and do not constitute a guarantee by the Seller that Energy will be delivered in accordance with the schedules and do not limit the amount of Energy the Seller may deliver during the periods covered by the schedules. The Seller shall deliver a revised schedule to the Buyer forthwith upon becoming aware of any expected material change in a filed Energy schedule."

5. Section 7.2 is deleted and replaced with the following:

    "7.2 **Modification to Hourly Firm Energy Amount -** The Seller may at any time prior to the first anniversary of COD, give notice to the Buyer that the Seller elects to increase or decrease any Hourly Firm Energy Amount to take effect on the first day of the month immediately following the giving of such notice, provided that the net change in the annual total of the Monthly Firm Energy Amounts resulting from such increases or decreases in any Hourly Firm Energy Amount does not exceed 10%. Upon receipt of such notice, the Buyer and the Seller shall execute an amendment to this EPA to amend Appendix 2 in accordance with the Seller's notice, provided that:

        (a) any such increase or decrease in any of the Hourly Firm Energy Amounts does not result in the total of the Monthly Firm Energy Amounts for the period from April to July, inclusive, exceeding one-third of the annual total of the Monthly Firm Energy Amounts;

(b) any such increase or decrease in the Hourly Firm Energy Amounts does not result in any Hourly Firm Energy Amount exceeding the Plant Capacity multiplied by 1 hour; and

(c) the provisions of subsections 4.2(a) and (b) apply to any such increase or decrease in the Hourly Firm Energy Amounts, *mutatis* mutandis; and

(d) the Seller may give only one notice under this section.

6. Section 7.3 is deleted and replaced with the following:

"7.3 **Post-COD Sale of Energy -** Subject to subsection 7.8(a), in each hour during the Term after COD, the Seller shall sell and deliver to the Buyer at the POI, the Hourly Firm Energy Amount for the applicable hour."

7. Section 7.4 is amended by deleting the word "month" and replacing it with "hour".

8. Section 7.9 is amended by:

(a) deleting the word "month" wherever it appears in that section, except in subsection 7.9(a)(ii), and replacing it with "hour"; and

(b) deleting the words "in that month" in subsection 7.9(a)(ii) and replacing them with "in the month for which the amount of Eligible Energy is being calculated"; and

(c) deleting the balance of the section after subsection (b) and replacing it with the following:

"then, notwithstanding that the Buyer is excused under subsection 7.8(b) from its obligations under section 7.4, in the case of an event described in subsection 7.9(a), that portion of the applicable Hourly Firm Energy Amount that could have been generated and delivered to the POI in each hour after the 24 hours has elapsed but for the occurrence of the event described in subsection 7.9(a), will be deemed to be Eligible Energy, and in the case of an event described in subsection 7.9(b), the amount of Energy, not exceeding the Plant Capacity, that could have been generated and delivered to the POI but for the occurrence of the event described in subsection 7.9(b) will be deemed to be Eligible Energy. The amount of Energy that could have been generated and delivered to the POI during an event described in subsection 7.9(a) or (b), will be determined based on the Seller's Energy schedule for each hour in the applicable period, meter readings with respect to the Energy Source, if applicable, readings of the Metering Equipment before and after the occurrence of the event described in subsection 7.9(a) or (b) and other available information. There will be no deemed Eligible Energy during any period specified as a Planned Outage period in a notice delivered by the Seller under section 6.4. For greater certainty, the provisions of section 7.9 will not apply during any period when either Party is excused, in accordance with Article 11, from its obligation to deliver, or to accept delivery of, Energy as a result of a Force Majeure.

9. Section 12.2 is deleted and replaced with the following:

"12.2 **Delivery Shortfalls -** If in any hour after the first anniversary of COD, the Delivered Eligible Energy in that hour is less than 90% of the Hourly Firm Energy Amount for that hour, the Seller shall pay LDs to the Buyer calculated as follows:

LD Amount = LD Factor * ((0.9 * Hourly Firm Energy Amount) – Delivered Eligible Energy)

Where:

(a) the Hourly Firm Energy Amount is the amount set out in Appendix 2 for the relevant hour less an amount equal to the Hourly Firm Energy Amount divided by 60 for each minute in which the Seller is excused under subsection 7.8(a) from the obligation to deliver Energy;

(b) "Delivered Eligible Energy" means in each hour the amount of Eligible Energy determined pursuant to subsection (a) of the definition of "Eligible Energy" for that hour, but excluding any Energy delivered after the start time and prior to the end time for an Authorized Planned Outage as set out in the notice with respect to the Authorized Planned Outage under section 6.4;

(c) LD Factor = the greater of: (i) zero and (ii) A-[(FEP/(1-L))+FEPA]

Where:

(i) A = the lesser of:

(I) the LD Cap; and

(II) the Mid-C Index;

(ii) L = ________%;

(iii) FEP = the Firm Energy Price for the hour in which the delivery shortfall occurred;

(iv) FEPA (Firm Energy Price Adjuster)$_n$ = $____/MWh * CPI$_{\text{January 1 n}}$/CPI $_{\text{January 1 2006}}$

Where:

n = the year for which the Firm Energy Price Adjuster is being calculated

CPI $_{\text{January 1 n}}$ = the CPI for December in the year immediately preceding the year for which the Firm Energy Price Adjuster is being calculated;

[Note to Bidders – L will be the greater of (i) zero and (ii) an amount determined from energy loss information used in the CFT evaluation. FEPA will be the sum of the following: -3.00 if the Green Attributes are transferred to BC Hydro; -3.00 to reflect the fact that the Bidder tendered an Hourly Firm Energy Profile; and X if GHG emission offset obligations are transferred to BC Hydro where "X" is the amount determined from the GHG Adjustment Table (CFT Reference Document), based on the Bidder's tendered Guaranteed GHG Intensity]

(v) "Mid-C" means the mid-Columbia electricity region;

(vi) "Mid C Index" means the Dow Jones Mid-C daily firm On-Peak Index, the Dow Jones Mid-C daily firm Off-Peak Index or, on NERC holidays only, the Dow Jones Mid-C 24 hour firm Sunday and NERC Holidays Index as applicable to the hour in which the delivery shortfall occurred. Amounts quoted in U.S. dollars will be converted to Canadian dollars using the Bank of Canada daily "noon rate" for the day in which the delivery shortfall occurred;

(vii) "LD Cap" means \$100/MWh adjusted effective as of January 1 in each year after the Effective Date in accordance with the following formula:

LD Cap_n = \$100/MWH * $CPI_{January\ 1\ n}/CPI_{January\ 1\ 2006}$, as further adjusted to an amount (expressed in \$/MWh) equal to the amount determined in accordance with the foregoing calculation multiplied by the percentage of the Escalated Bid Price adjustment applicable to the month and hour in which the delivery shortfall occurred as set out in the table in section 3.4 of Appendix 3

Where:

n = the year for which the escalated LD Cap is being calculated

$CPI_{January\ 1\ n}$ = the CPI for December in the year immediately preceding the year for which the escalated LD Cap is being calculated.

Any LDs owing by the Seller to the Buyer pursuant to this section 12.2 shall be payable on 15th day of the month following the month in which the delivery shortfall occurred."

10. Section 12.3 is amended by deleting the word "Monthly" and replacing it with "Hourly".

11. Subsections 15.4(a) and 15.5(a) are amended by deleting the words "set out in Appendix 2" and by inserting the word "annual" before the words "Monthly Firm Energy Amounts" in both sections.

12. Subsection (e) in the definition of "**Buyer Termination Event**" in Appendix 1 is amended by deleting the word "Monthly" and replacing it with "Hourly".

13. The definition of "**Eligible Energy**" in Appendix 1 is amended by deleting the word "month" and replacing it with "hour".

14. The following definition is added to Appendix 1:

"**Hourly Firm Energy Amount**" means for each hour after COD, the amount of Energy the Seller is required to deliver in that hour as set out in Appendix 2."

15. The definition of "**Monthly Firm Energy Amount**" in Appendix 1 is deleted and replaced with the following:

"**Monthly Firm Energy Amount**" means for each month after COD the sum of the Hourly Firm Energy Amounts for that month calculated based on the number of hours for that month set out in Part 2 of Appendix 2.

16. The definition of **"Monthly Firm Energy Delivery Rate"** is deleted from Appendix 1.

17. The definition of "**Performance Security**" in Appendix 1 is amended by deleting the words "set out in Appendix 2", and by inserting the word "annual" prior to the words "Monthly Firm Energy Amounts".

18. The note with respect to leap years at the bottom of Appendix 2 is deleted.

19. The definition of "**Firm Energy**" in section 1.1 of Appendix 3 is deleted and replaced with the following:

    "**Firm Energy**" means in each hour of the Term after COD all Eligible Energy in that hour not exceeding the Hourly Firm Energy Amount for that hour, but excluding any Eligible Energy delivered after the start time and prior to the end time for an Authorized Planned Outage as set out in the notice with respect to the Authorized Planned Outage under section 6.4 and all such Eligible Energy will be considered Non-Firm Energy.

20. The definition of "**Non-Firm Energy**" in Appendix 3 is deleted and replaced with the following:

    "**Non-Firm Energy**" means in each hour of the Term after COD all Eligible Energy in that hour in excess of the Hourly Firm Energy Amount for that hour and all Eligible Energy deemed to be Non-Firm Energy pursuant to subsection 1.1(f) of this Appendix.

21. The definition of "**Tier 1 Non-Firm Energy**" in Appendix 3 is deleted and replaced with the following:

    "**Tier 1 Non-Firm Energy**" means in each hour of the Term after COD all Eligible Energy in that hour in excess of the Hourly Firm Energy Amount not exceeding an amount equal to the Hourly Firm Energy Amount for that hour.

22. The definition of "**Tier 2 Non-Firm Energy**" in Appendix 3 is deleted and replaced with the following:

    "**Tier 2 Non-Firm Energy**" means in each hour during the Term after COD all Non-Firm Energy in excess of the Tier 1 Non-Firm Energy for that hour.

23. Section 3.5 of Appendix 3 is deleted.

PART B - PROJECTS THAT RECEIVE GREEN CREDIT

This Part applies to Sellers that tendered the Green Attributes to BC Hydro in the CFT process.

1. **Definitions -** The following definitions are added to Appendix 1:

"**Green Reduction Amount**" or "**GRA**" means \$3.00/ MWh as adjusted effective as of January 1 in each year after the Effective Date in accordance with the following formula:

$GRA_n = \$3.00/MWh * CPI_{January\ 1\ n}/CPI_{January\ 1\ 2006}$

Where:

n= the year for which the Green Reduction Amount is being calculated

$CPI_{January\ 1\ n}$ = the CPI for December in the year immediately prior to the year for which the Green Reduction Amount is being calculated.

"**EcoLogo^{M} Certified Energy Amount**" means the amount of Eligible Energy in each year that qualified for the EcoLogo^{M} designation as evidenced in a certificate delivered by the Seller to the Buyer under section 7A.5.

"**On-Site Emission Reduction Rights**" means any credit, reduction right, offset, allowance, allocated pollution right, certificate or other unit of any kind whatsoever, whether or not tradeable, resulting from, or otherwise related to the reduction, removal, avoidance, sequestration or mitigation of emissions at or from the Seller's Plant.

2. The definition of "**Green Attributes**" in Appendix 1 is amended by deleting subsection (b)(ii) from that definition and by adding the following words at the end of the definition: "but excluding any On-Site Emission Reduction Rights and any of the foregoing that arise in connection with Pre-COD Energy, other than Test Energy paid for by the Buyer under section 2.2 of Appendix 3".

3. Subsection 6.2(a) is amended by adding the words "and under section 7A.5" after the words "subsection 6.3(f)".

4. **Replacement of section 7.10 -** Section 7.10 is deleted and the following is added as Article 7A:

7A. - GREEN ATTRIBUTES

7A.1 **Transfer of Green Attributes -** The Seller hereby transfers, assigns and sets over to the Buyer all right, title and interest in and to the Green Attributes. The Buyer shall not be required to make any payment for the Green Attributes other than payment for Eligible Energy in accordance with Appendix 3. The Seller, upon the reasonable request of the Buyer, shall do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required to give effect to this section.

7A.2 **On-Site Emission Reduction Rights -** The Seller retains all right, title and interest in and to any On-Site Emission Reduction Rights.

7A.3 **Exclusivity -** Except as set out in section 7A.13, the Seller shall not commit, sell, or transfer any Green Attributes to any Person other than the Buyer, or otherwise use or apply any Green Attributes for any purpose whatsoever at any time during the Term. The

Seller shall ensure that all marketing materials produced by or for the Seller, all public or other statements by the Seller and all other communications by the Seller in any form whatsoever, contain no false or misleading statements concerning the ownership of the Energy or Green Attributes or the destination, end user or recipient of the Energy or Green Attributes. The Seller acknowledges that damages are not an adequate remedy to the Buyer for a breach by the Seller of this section and that the Buyer shall be entitled to an injunction to prevent any breach by the Seller of this section and to an order requiring the Seller to take such other actions as may be required to remedy the effects of any breach of this section.

7A.4 **Representations and Warranties -** The Seller represents and warrants to the Buyer and acknowledges that the Buyer is relying on those representations and warranties in entering into this EPA that the Seller is the legal and beneficial owner of the Green Attributes free and clear of all liens, claims, charges and encumbrances of any kind whatsoever and no other Person has any agreement or right of any kind whatsoever to purchase or otherwise to acquire or to claim or otherwise make any use whatsoever of the Green Attributes.

7A.5 **EcoLogo^{M} Certification -** The Seller shall obtain EcoLogo^{M} Certification by the first anniversary of COD and shall maintain the EcoLogo^{M} Certification throughout the remainder of the Term. By May 15 in each year after COD, the Seller shall deliver to the Buyer a certificate issued pursuant to Environment Canada's Environmental Choice^{M} program certifying the amount (MWh) of Eligible Energy delivered by the Seller to the Buyer in the immediately preceding year that qualified for the EcoLogo^{M} designation. The Seller shall notify the Buyer forthwith if the seller fails to obtain EcoLogo^{M} Certification by the date specified in this section or if at any time during the Term the Seller does not have EcoLogo Certification.

7A.6 **Alternate Certification -** The Seller shall at the Buyer's request and at the Buyer's cost use commercially reasonable efforts to apply for and diligently pursue and maintain any additional or alternate certification, licensing or approval offered by any Governmental Authority or independent certification agency evidencing that the Seller's Plant and the Energy has Green Attributes. Any failure by the Seller to use commercially reasonable efforts pursuant to this section is a "material default" for purposes of this EPA, and the Buyer may terminate the EPA under subsection 15.1(d).

7A.7 **Fees -** Except as set out in this section, the Buyer shall reimburse the Seller for all certification, audit and licensing fees paid by the Seller to obtain the EcoLogo^{M} Certification (including the annual certificate described in section 7A.5) or any alternate certification under section 7A.6, but excluding any fees to obtain the letter from TerraChoice Environmental Marketing required pursuant to the CFT. The Buyer shall reimburse the Seller for such fees within 30 days after receipt of an invoice, together with reasonable supporting information, for such fees. The Buyer shall not be required to pay for any audit or other certification process in which the Seller's Plant and all or part of the Energy does not qualify for EcoLogo^{M} Certification, or for any audit or recertification process following a loss of EcoLogo^{M} Certification by the Seller's Plant, and the Seller shall pay all costs associated with any such audit and certification process.

7A.8 **Energy Price Reduction -** If:

(a) the Seller fails to obtain EcoLogo^{M} Certification by the date specified in section 7A.5; or

(b) at any time during the Term the Seller's Plant does not have EcoLogo^{M} Certification for any reason whatsoever,

then the Escalated Bid Price for Eligible Energy will be reduced by an amount equal to the Green Reduction Amount. In the case of subsection (a) above, such reductions shall take effect from COD and the Seller shall within 30 days after receipt of an invoice from the Buyer, refund to the Buyer an amount equal to the Green Reduction Amount multiplied by the amount of Eligible Energy in respect of which the Seller has received payment from and after COD. In the case of subsection (b) above the reduction will take effect from and after the date on which the EcoLogo^{M} Certification ceased to be in effect and the Seller shall within 30 days after receipt of an invoice from the Buyer, refund to the Buyer an amount equal to the Green Reduction Amount multiplied by the amount of Eligible Energy in respect of which the Seller has received payment from and after the date on which the EcoLogo^{M} Certification ceased to be in effect. For greater certainty, notwithstanding any payment reduction pursuant to this section, the Buyer will throughout the remainder of the Term have title to the Green Attributes and the provisions of section 7A.3 will remain in effect.

7A.9 **Restoration of Price -** If the Escalated Bid Price is reduced under section 7A.8 and thereafter the Seller demonstrates to the Buyer that the Seller's Plant has obtained EcoLogo^{M} Certification, other than as a result of expenditures by the Buyer under section 7A.10, or if the Seller obtains an alternate certification at the Buyer's request under section 7A.6, then from and after the date on which the Seller provides such evidence to the Buyer or obtains such alternate certification the Escalated Bid Price will no longer be reduced by an amount equal to the Green Reduction Amount.

7A.10 **Cure by the Buyer -** If the Seller fails to obtain or maintain EcoLogo^{M} Certification, as required under section 7A.5 or any alternate certification under section 7A.6, then in addition to applying the payment reduction specified in section 7A.8 (applicable only to the EcoLogo^{M} Certification), the Buyer in its sole and unfettered discretion, may direct the Seller to take all steps required to obtain EcoLogo^{M} Certification or an alternate certification by implementing measures that are technologically feasible and not inconsistent with Good Utility Practice, Permits or Applicable Laws and the Seller shall comply promptly and diligently with that direction. Except where the failure to obtain or maintain EcoLogo^{M} Certification or an alternate certification results from a breach of Laws or Permits, the Buyer shall reimburse the Seller for reasonable direct capital and incremental operating costs incurred by the Seller resulting from compliance with the Buyer's direction within 30 days after submission of an invoice and supporting documentation reasonably satisfactory to the Buyer to evidence such costs. The Seller shall maintain accurate and complete records of such costs, and the Buyer or its designated representative may audit such costs and in that event the Seller shall provide all reasonable cooperation to the Buyer or its designated representative including access to all original records related to such costs. For greater certainty, notwithstanding the performance and completion of compliance measures under this section and the grant or reinstatement of EcoLogo^{M} Certification, the payment reductions under section 7A.8 will continue in effect for the remainder of the Term and the Buyer will continue to have title to the Green Attributes.

7A.11 **Termination -** If the Seller fails to comply promptly and diligently with a direction under section 7A.10 and such failure is not cured within 30 days of notice from the Buyer to the Seller, then the Seller will be in material default of its obligations under this EPA and the Buyer may terminate the EPA under subsection 15.1(d).

7A.12 **Exclusive Remedy -** The remedies set out or referenced in sections 7A.6, 7A.8, 7A.10 and 7A.11 are the sole and exclusive remedies available to the Buyer for any failure by the Seller to obtain or maintain EcoLogo^{M} Certification or any alternate certification.

7A.13 **Transfer to Governmental Authority -** If the Seller has been notified that the Seller's Plant or the Energy qualifies for Canada's Renewable Power Production Incentive or Wind Power Production Incentive or any other Governmental Authority incentive associated with the generation of energy with specified environmental attributes and the transfer of the Green Attributes to the applicable Governmental Authority is required for the Seller to obtain the incentive, the Buyer shall transfer the Green Attributes to such Governmental Authority, provided that the Seller has given notice to the Buyer pursuant to this section by not later than COD. If the Buyer is required to transfer the Green Attributes to a Governmental Authority pursuant to this section, then the Parties shall enter into an amendment to this EPA to delete Article 7A from the EPA and to reduce the Escalated Bid Price by an amount equal to the Green Reduction Amount for all Eligible Energy delivered or deemed to be delivered from and after the date of the notice by the Seller to the Buyer under this section and the Seller shall within 15 days after receipt of an invoice, reimburse the Buyer for all costs incurred by the Buyer under section 7A.7 prior to the date of notice from the Seller under this section.

7A.14 **Information Requirements -** Without limiting section 6.5, the Seller shall maintain, and shall within 10 Business Days after a request from the Buyer, provide to the Buyer: (a) all information the Buyer requires to verify the quantity of Energy generated by the Seller's Plant, qualification of the Seller's Plant and all or part of the Energy for EcoLogo^{M} Certification or an alternate certification under section 7A.6, the status of the EcoLogo^{M} Certification or an alternate certification under section 7A.6, and the existence, nature and quantity of Green Attributes; (b) any information required for the purposes of any Green Attribute or energy tracking system as directed by the Buyer; and (c) any other information the Buyer requires to enable the Buyer or its Affiliates to obtain or realize the full benefit of the Green Attributes, including sales of the Green Attributes to third parties, provided that if the Buyer requests any information pursuant to subsection (b) or (c) above that the Seller would not otherwise be required to maintain for purposes of administering this EPA, the Buyer shall reimburse the Seller for all reasonable costs incurred by the Seller in obtaining or maintaining such information.

7A.15 **Audit Rights -** The Buyer, any Affiliate of the Buyer and any third Person who has entered into a contract with the Buyer or any Affiliate of the Buyer to purchase Green Attributes may at any time during the Term conduct or have a third Person with the necessary expertise conduct, at the Buyer's expense, an audit of the Project Assets to verify compliance with the requirements for EcoLogo^{M} Certification or an alternate certification under section 7A.6. The Seller shall promptly provide any consents required to enable the Buyer, any Affiliate of the Buyer or any third Person who has entered into a contract with the Buyer to purchase Green Attributes to: (i) make enquiries with

Governmental Authorities concerning the status of compliance by the Seller and the Seller's Plant with applicable Laws and Permits; (ii) make enquirities of TerraChoice Environmental Marketing or any other third Person regarding the status of the EcoLogo^{M} Certification; and (iii) obtain copies of all audits, reviews or inspections conducted by the Seller, TerraChoice Environmental Marketing or any other third Person in connection with the application by the Seller to obtain and maintain EcoLogo^{M} Certification, or any alternate certification under section 7A.6.

7A.16 **Confidentiality -** The Seller consents to the disclosure to any Person or any Governmental Authority of any Confidential Information with respect to the Energy and/or the Seller's Plant the Buyer is required to disclose to enable the Buyer to obtain or realize the full benefit to the Buyer of the Green Attributes, including sales of Green Attributes to third parties.

7A.17 **Annual Payment Calculation -** By not later than June 15 in each year after COD the Seller shall pay to the Buyer an amount calculated in accordance with the following formula:

Payment Amount = the greater of (**a**) zero and (**b**) the amount determined in accordance with the following formula:

[(AxB)-C] x GRA

Where:

A = the percentage of Energy Source(s), as set out in Appendix 5, that is designated as acceptable to generate energy that qualifies for EcoLogo^{M} Certification in the letter from TerraChocie Environmental filed with the Seller's Tender.

B = the total amount of Eligible Energy (as determined under subsection (a) of the definition of Eligible Energy) delivered by the Seller to the Buyer in the immediately preceding year.

C = the EcoLogo^{M} Certified Energy Amount.

The foregoing amount shall only be payable by the Seller for periods in which subsection 7A.8 does not apply.

5. Subsection 15.3(b)(ii)(A) is amended by adding the following as subsection (V): "Article 7A with respect only to Green Attributes associated with Eligible Energy delivered prior to termination of the EPA; and".

PART C - PROJECTS THAT TRANSFER GHG EMISSION OFFSET LIABILITY TO BUYER

This Part applies to Sellers that elected in the CFT process to transfer to BC Hydro responsibility for any regulatory obligation to purchase GHG-related Compliance Units up to the Guaranteed GHG Intensity tendered by the Seller in the CFT process.

1. Definitions - The following definitions are added to Appendix 1:

   "**Actual GHG Intensity**" means the actual GHG Intensity of the Seller's Plant in each year.

   "**GHG Intensity**" means:

   (i) the GHG intensity for the Seller's Plant determined in the manner specified under any Laws or Permits applicable to the Seller's Plant, provided that notwithstanding any provision to the contrary in any such Laws or Permits, the GHG intensity for the Seller's Plant will be determined without regard to any other facilities owned or operated by the Seller, any Affiliate of the Seller or any other Person; or

   (ii) if there is no Law or Permit in effect which specifies the method of calculating the GHG intensity for the Seller's Plant, the GHG intensity determined by dividing the total GHG emissions from the Seller's Plant in the year for which the calculation is being conducted (expressed as metric tonnes of CO_2 equivalent) by the total amount of Eligible Energy (as determined under subsection 7(a) of the definition of "Eligible Energy") for that year.

   "Guaranteed GHG Intensity" means ___TO#6______ metric tonnes CO_2 e/ MWh.

2. Section 6.8 is amended by adding the following words at the beginning of that section:

   "Subject to section 6.12:"

3. The following is added as section 6.12:

   6.12 GHG Compliance Unit Obligation - In each year after COD, on or before the date required pursuant to applicable Laws and Permits, and provided that the Seller has complied with its obligations under this section, the Buyer shall deliver to the Seller that number of Compliance Units calculated in accordance with the following formula:

   RCUs = the greater of: (i) zero and (ii) ([the lesser of AGHGI and GGHGI] - PI) * DE

   Where:

   RCUs = the number of Compliance Units (in metric tonnes CO_2 e/MWh) the Buyer is required to deliver to the Seller

   AGHGI = the Actual GHG Intensity

   GGHGI = the Guaranteed GHG Intensity

   PI = the GHG Intensity permitted under applicable Laws and Permits for the Seller's Plant

DE = the amount of Eligible Energy delivered by the Seller to the POI during the immediately preceding calendar year.

The Seller shall: (a) by the date that is 30 days prior to the date on which the Buyer is required to deliver Compliance Units to the Seller under this section, deliver a statement to the Buyer, together with all information required to support the statement, setting out the GHG intensity target for the Seller's Plant under applicable Laws and Permits, the Actual GHG Intensity for the immediately preceding year, and the number of Compliance Units the Buyer and the Seller are required to obtain by the date specified in this section; and (b) if the Actual GHG Intensity exceeds the Guaranteed GHG Intensity, obtain any Compliance Units required under applicable Laws and Permits with respect to such excess intensity and provide evidence to the Buyer that the Seller has obtained such Compliance Units. The Seller is responsible for obtaining any Compliance Units required for the period prior to COD. The parties shall enter into any amendment to this section required to reflect the reporting and compliance dates established under applicable Laws and Permits regulating GHG emissions from the Seller's Plant.

PART D - GHG COMPLIANCE COMMITMENT

This Part applies to Sellers that elect in the CFT process to comply with a contractually binding GHG intensity.

1. The following is added as section 6.12 as applicable:

   6.12 GHG Compliance Commitment - The Seller shall ensure that the Seller's Plant has a GHG intensity of not more than _TO#7__ metric tonnes CO_2e/MWh in each year. The Seller shall in the reports required to be delivered by the Seller pursuant to subsection 6.8(a) detail the status of compliance by the Seller with this section during the immediately preceding calendar quarter. If the Seller is not in compliance with the requirements of this section and the Seller fails to remedy such non-compliance within 30 days after the date of notice from the Buyer to the Seller, the Buyer may, but is not required to, on behalf of the Seller, purchase those Compliance Units that are required to remedy, in whole or in part, the Seller's non-compliance with the requirements of this section and the provisions of section 6.8(a) shall apply to such purchase, *mutatis mutandis*. Any failure by the Seller to comply with this section is a "material default" for the purposes of the definition of "Buyer Termination Event" in Appendix 1. Notwithstanding the foregoing, the Seller remains bound by the provisions of section 6.8 in addition to the foregoing commitment.

2. Subsection 9.5(a) is amended by adding the words "or section 6.12" at the end of that subsection.

3. Subsection 9.5(b) is amended by adding the words "or section 6.12" after the words "section 6.8" wherever those words appear in that subsection.

4. Section 12.5 is amended by adding the words "or 6.12" after the words "6.8" in that section, and by deleting the word "or" before the word "6.8" in that section.

5. Section 13.3 is amended by adding the words "or 6.12" after the word "6.8" in that section, and by deleting the word "or" before the word "6.8" in that section.

6. Subsection 15.3(a) is amended by adding the words "or 6.12" after the word "6.8" in that section, and by deleting the word "or" before the word "6.8" in that section.

PART E - PROJECTS INTERCONNECTED TO THE TRANSMISSION SYSTEM OR DISTRIBUTION SYSTEM THROUGH AN INDUSTRIAL HOST FACILITY

This Part applies to Sellers that tendered a Project that has an Indirect Interconnection (as defined in the CFT Glossary) to the Transmission System/Distribution System through an industrial host facility.

1. The provisions of this Part E are applicable for so long as the Electrical Host purchases electricity from the Buyer. If the Electrical Host ceases to purchase electricity from the Buyer, the provisions of this Part E, other than sections 5 and 6, cease to have effect, the Seller shall be required to deliver all Energy to the POI or to such other point of interconnection with the ***[Distribution System/Transmission System]*** as the Parties may agree in writing and the Parties shall enter into an amendment to the EPA to reflect the foregoing. ***[Note to Bidders: The words in bold will be finalized depending on the POI for the bidder's plant.]***

2. Section 6.4 is amended by adding the words "or on the Electrical Host" after the words "materially adverse effect on the operation of the Seller's Plant".

3. Section 7.6 is amended by adding the following at the end of that section:

   Deliveries of Eligible Energy to an Electrical Host to service the Electrical Host's electricity requirements will be deemed to be deliveries of Eligible Energy to the Buyer at the POI for purposes of this EPA to the extent such deliveries displace deliveries of electricity from the Buyer to the Electrical Host.

4. Appendix 1 is amended by:

   (a) adding the following definition:

   "**Electrical Host**" means a facility which is not itself an electrical generating facility and which is located between the Seller's Plant and the POI, where the Seller's Plant is providing electricity to the facility and the Seller's Plant does not have an independent connection to the *[Transmission System/Distribution System]*.

   [Note to Bidders - Where a Bidder is proposing to Tender a Project that is interconnected to the Distribution System or the Transmission System through an Electrical Host, BC Hydro will review its electricity supply contract(s) relating to that Electrical Host and will advise the Bidder prior to the Tender Closing Time of any amendments required to such electricity supply contract(s) to accommodate the Project. Any Tender for such a Project will be deemed to incorporate those amendments or must be accompanied by an appropriate amending agreement signed by the owner of the Electrical Host.]

   (b) deleting the definition of "**POI**" and replacing it with the following:

   "**POI**" or "**Point of Interconnection**" means the point of interconnection which is the point at which the Electrical Host interconnects with the ***[Transmission System/Distribution System]*** as more particularly described in the interconnection agreement between the Electrical Host and the ***Transmission Authority/Distribution Authority***."

5. Everywhere in this EPA where the words "Energy delivered to the POI" or words of similar meaning appear, the words "or deemed pursuant to section 7.6 to be delivered to the POI" are deemed to follow immediately thereafter.

6. All of the provisions of Part G, Appendix 10 are applicable.

7. The Seller will be responsible for, and shall pay within 30 days after receipt of an invoice from the Buyer, all costs reasonably incurred by the Buyer and/or the Electrical Host as required to implement any amendments required to any Electricity Supply Agreement between the Buyer and the Electrical Host as a result of provisions of section 7.5 of the EPA and the interconnection arrangements for the Seller's Plant.

PART F - PROJECTS INTERCONNECTED TO THE DISTRIBUTION SYSTEM

This Part applies to Sellers that tendered a Project that interconnects with the Distribution System.

1. Subsection 4.2(a) is amended by adding the words "Distribution Authority and the" before the words "Transmission Authority" in that subsection.

2. Section 4.5 is amended by:

    (a) deleting the words "Transmission System" and replacing them with "Distribution System"; and

    (b) adding the words "and the Distribution Authority" after the words "Transmission Authority" in that section.

3. Subsection 5.2(d)(i) is amended by deleting the words "Transmission Authority" and replacing them with "Distribution Authority".

4. Section 5.6 is amended by:

    (a) adding the words "and Direct Assignment Facilities" after the words "Network Upgrades" wherever the words "Network Upgrades" appear in that section; and

    (b) adding the words "or the Distribution Authority" after the words "the Buyer" in the first sentence of that section.

5. Section 5.7 is amended by adding the words "Distribution Authority and" before the words "Transmission Authority" wherever those words appear in that section.

6. Wherever the words "Facilities Agreement" appear in the EPA, except in the heading to section 20.9, the heading to subsection 6.6(d) and in the definition of "Facilities Agreement" in Appendix 1, the words ", if any," are added immediately thereafter.

7. Section 6.3 is amended by deleting the words "Transmission System" and replacing them with "Distribution System".

8. Section 6.4 is amended by adding the words "and the Distribution Authority's" after the words "Transmission Authority's".

9. Section 6.9 is amended by adding the words "and the Distribution Authority" after the words "the Transmission Authority" in that section.

10. Subsection 7.8(a) is amended by deleting the words "Transmission System" and replacing them with "Distribution System" and deleting the words "Transmission Authority" and replacing them with "Distribution Authority".

11. Subsections 7.8(b)(ii) and (iii) are deleted and replaced with the following and subsection (iv) is renumbered as subsection (iii):

    (ii) disconnection of the Seller's Plant from the Distribution System, and any Outage, suspension, constraint or curtailment in the operation of the Distribution System preventing or limiting physical deliveries of Eligible Energy at the POI, provided that the disconnection, Outage, suspension, constraint or curtailment: (A) results from any Outage, suspension, constraint, curtailment or other event of any kind on the Distribution System; or (B) is implemented pursuant to the Interconnection Agreement, Facilities Agreement, if any, or any other legally enforceable right;

12. Subsection 7.9(a) is deleted and replaced with the following:

"(a) any disconnection of the Seller's Plant from the Distribution System or any Outage or Outages on the Distribution System or any suspension, constraint or curtailment in the operation of the Distribution System preventing or limiting physical deliveries of Eligible Energy at the POI where such Outages, suspensions, constraints or curtailments exceed, in the aggregate 24 hours, whether or not continuous, in that month, other than a disconnection, Outage, suspension, constraint or curtailment attributable to the Seller or the Seller's Plant; or"

13. Section 8.1 is amended by adding the words "and Distribution Authority" after the words "Transmission Authority".

14. Subsection 11.2(f) is amended by deleting the words "Transmission System" and replacing them with "Distribution System".

15. Section 20.9 is deleted and replaced with the following:

"**20.9 Interconnection Agreement and Facilities Agreement -** Nothing in the Interconnection Agreement or the Facilities Agreement, if any, and no exercise of any right thereunder, restricts or otherwise affects any right, obligation or liability of either Party under this EPA, except to the extent set out expressly herein, and no notice, consent, approval or other communication or decision under or in relation to the Interconnection Agreement or the Facilities Agreement, if any, shall constitute or be relied upon as a notice, consent, approval or communication or decision under this EPA, and this EPA shall be interpreted and applied as though the Distribution Authority were a third party, including for purposes of determining whether or not a Force Majeure has occurred."

16. The definition of "**Buyer Termination Event**" in Appendix 1 is amended by deleting subsection (c) from that definition and replacing it with the following:

"(c) the Seller has not by the date that is the earlier of: (i) 60 days after the date of award of this EPA pursuant to the CFT; and (ii) 240 days after the date of issuance by the Distribution Authority to the Seller of the F2006 CFT Preliminary Interconnection Study Report, executed and delivered to the Distribution Authority an application for an impact/design study where the interconnection of the Seller's Plant will have no impact on the Transmission System, or, where the interconnection of the Seller's Plant will have an impact on the Transmission System, an interconnection impact study and any related studies, together with the applicable study fee in the form and amount prescribed by the Distribution Authority;"

17. The definition of "**Combined Study Agreement**" in Appendix 1 is deleted.

18. The definition of "**Facilities Agreement**" in Appendix 1 is amended by deleting the words "Transmission Authority" and replacing them with "Distribution Authority".

19. The definition of "**Force Majeure**" in Appendix 1 is amended by adding the words "or the Distribution Authority" after the words "Transmission Authority" in that section.

20. The words "Transmission System" in the definition of "**Interconnection**" in Appendix 1 are deleted and replaced with the words "Distribution System".

21. The words "Transmission Authority" in the definition of "**Interconnection Agreement**" in Appendix 1 are deleted and replaced with "Distribution Authority".

22. The definition of "**Outage**" in Appendix 1 is amended by adding the words "Distribution System and" before the words "Transmission System" in that definition.

23. The definition of "**POI**" in Appendix 1 is amended by deleting the words "Transmission System" and replacing them with "Distribution System".

24. The definition of "**Seller's Plant**" in Appendix 1 is amended by deleting the words "Transmission System" and replacing them with "Distribution System".

25. If Part G of Appendix 10 is applicable, then:

    (a) paragraph 11 of this Part is amended by deleting the words "and subsection (iv) is renumbered as subsection (iii)" and replacing them with the words "and subsections (iv) and (v) are renumbered as subsections (iii) and (iv);

    (b) subsection 7.8(b)(iv), as added by Part G of Appendix 10 and renumbered by section 11 of this Part F, is amended by deleting the words "Transmission System" and replacing them with "Distribution System";

    (c) subsection 7.9(a) is deleted and replaced with the following:

    "any disconnection of the Seller's Plant or the Private Line from the Distribution System or any Outage or Outages on the Distribution System or any suspension, constraint or curtailment in the operation of the Distribution System, exceeding in the aggregate 24 hours, whether or not continuous, in that month, other than a disconnection, Outage, suspension, constraint or curtailment attributable to the Seller or the Seller's Plant or to the Private Line Owner or any of the Private Line Owner's facilities; or";

    (d) subsection 11.2(i), as added by Part G of Appendix 10, is amended by deleting the words "Transmission System" and replacing them with "Distribution System";

    (e) subsection (c) of the definition of "**Buyer Termination Event**" as amended by paragraph 16 of this Part F is amended by adding the words "or the Private Line Owner" after the word "Seller" wherever that word appears in that subsection;

    (f) the Note to Bidders under the definition of "**POI**" as added by Part G of Appendix 10 is amended by deleting the word "Transmission" and replacing it with "Distribution"; and

(g) the definition of "**Private Line**" and the related Note to Bidders as added by Part G of Appendix 10, is amended by deleting the word "Transmission" and replacing it with "Distribution".

26. If Part I of Appendix 10 (Split Bid Projects) applies, then section 4.6 of the EPA (added by Part I of Appendix 10) is amended by adding the words "or the Distribution Authority" after the words "Transmission Authority" in that section.

PART G - PROJECTS INTERCONNECTED TO THE TRANSMISSION SYSTEM OR DISTRIBUTION SYSTEM THROUGH A PRIVATELY-OWNED TRANSMISSION OR DISTRIBUTION LINE

This part applies to Sellers who submit an F2006 CFT Preliminary Interconnection Study Report with their Tenders which indicates that the Seller's Plant will be interconnected to the Transmission System or Distribution System through a privately-owned transmission or distribution line, including a Project that has an Indirect Connection through an industrial host facility.

1. Section 4.2 is amended by:

    (a) adding the following as subsection (e) and renumbering existing subsections (e) and (f) as (f) and (g):

    "(e) the Seller has entered into an agreement with the Private Line Owner amending the Private Line Agreement as required to accommodate the increase or decrease in the Plant Capacity and has provided a copy of the amending agreement to the Buyer (with any confidential information redacted) or has provided evidence satisfactory to the Buyer, acting reasonably, that no such amendments are required";

    (b) deleting the words "subsections (a) and (c)" in the sentence immediately following subsection (g) (as renumbered in accordance with the foregoing) and replacing them with "subsections (a), (c) and (e)".

2. Section 4.5 is amended by:

    (a) deleting the first sentence and replacing it with the following:

    "If the Private Line Owner makes any change to the point of interconnection between the Private Line and the Transmission System (including any change to the point of interconnection specified in the F2006 CFT Preliminary Interconnection Study Report), the Seller shall notify the Buyer forthwith upon the Seller becoming aware of such change or proposed change and the Seller shall enter into an amendment to this EPA as required to put the Buyer in the position it would have been in under this EPA had the point of interconnection between the Private Line and the Transmission System not been changed, including with respect to the amount of Eligible Energy."; and

    (b) adding the words "or the Private Line Owner" after the word "Seller" at the beginning of the second sentence.

3. Subsection 5.2(c) is amended by adding the words "or under the Private Line Agreement" at the end of that subsection.

4. Subsection 5.2(d)(i) is amended by adding the words "or the Private Line Owner" after the words "to the Seller".

5. Section 5.2 is amended by:

   (a) adding the following as subsection 5.2(e) and changing the comma at the end of subsection 5.2(d) to a semicolon, adding the word "and" after the semicolon and deleting the word "and" at the end of subsection 5.2(c):

   "(e) the Private Line Owner is not in default under the Interconnection Agreement or the Facilities Agreement,"; and

   (b) deleting the words "subparagraphs (a) to (d)" in the last sentence of that Section and replacing them with "subparagraphs (a) to (e)".

6. Subsection 6.3(g) is amending by adding the words and the Private Line Agreement" at the end of that subsection.

7. Subsection 6.6(d) is amended by adding the words "or the Private Line Agreement" after the words "Interconnection Agreement" and by adding the words "or the Private Line Owner" after the word "Seller" at the end of the subsection.

8. Section 6.9 is amended by adding the following at the end of that section:

   "The Seller shall promptly on request by the Buyer provide to the Buyer a consent in similar form signed by the Private Line Owner for delivery to the Transmission Authority provided that in such consent all references to the "Seller" in subsections (a) and (d) will be replaced by the "Private Line Owner".

9. Section 6.10 is amended by:

   (a) adding the following after the first sentence in that section:

   "The Seller shall use commercially reasonable efforts to obtain any information or cooperation that may be required from the Private Line Owner to complete those studies and cost estimates."; and

   (b) adding the words "(including reasonable amounts paid to the Private Line Owner to reimburse the Private Line Owner for costs incurred in providing information or cooperation as requested by the Buyer)" after the words "all reasonable costs incurred by the Seller".

10. Section 7.2 is amended by adding the following as subsection (e) and changing the period at the end of subsection (d) to a semicolon and inserting the word "and" and deleting the word "and" at the end of subsection 7.2(c):

   "(e) the Seller has entered into an agreement with the Private Line Owner amending the Private Line Agreement as required to accommodate the increase or decrease in the Monthly Firm Energy Amounts and has provided a copy of the amending agreement to the Buyer (with any confidential information redacted) or has provided evidence satisfactory to the Buyer, acting reasonably, that no such amendments are required."

11. Subsection 7.8(a) is amended by:

    (a) adding the words "or the Private Line Owner or any of the Private Line Owner's facilities" at the end of subsections 7.8(a)(ii) and (iii); and

    (b) adding the following as subsection (vi) and by changing the period at the end of subsection (v) to a semicolon and adding the word "and" after the semicolon and deleting the word "and" at the end of subsection (iv):

        "(vi) disconnection of the Private Line from the Transmission System by the Transmission Authority for reasons that are not attributable to the Seller or the Seller's Plant or the Private Line Owner or any of the Private Line Owner's facilities.".

12. Subsection 7.8(b) is amended by adding the following as subsection (v) and by changing the period at the end of subsection (iv) to a semicolon and adding the word "and" after the semicolon and deleting the word "and" at the end of subsection (iii):

    "(v) disconnection of the Private Line from the Transmission System for reasons not attributable to the Buyer.".

13. Subsection 7.9(a) is amended by:

    (a) adding the words "or the Private Line" after the words "Seller's Plant" in the first line;

    (b) adding the words "or the Private Line" after the words "Seller's Plant" in subsection 7.9(a)(i); and

    (c) adding the words "or to the Private Line Owner or any of the Private Line Owner's facilities" at the end of the subsection.

14. Subsection 8.1(c) is amended by adding the following at the end of that subsection:

    "and after adjusting for any incremental losses associated with the transmission of energy from any other generating facility connected to the Private Line where: (i) the output from that other generating facility is sold to the Buyer; (ii) the incremental losses have not been accounted for in the calibration of the meter for the other generating facility; and (iii) "incremental losses" refers to those losses that would not have occurred but for the transmission of Energy from the Seller's Plant to the POI through the Private Line".

15. Subsection 11.2(e) is amended by adding the words "including any act or omission of the Private Line Owner" after the words "of a Party".

16. Section 11.2 is amended by adding the following as subsection (h) and by deleting the period at the end of subsection (g) and replacing it with a semicolon and by adding the word "or" after the semicolon and deleting the word "or" at the end of subsection (f):

    "(h) for any disconnection of the Private Line from the Transmission System or any Outage, constraint or curtailment in the operation of the Private Line, except to the extent such disconnection, Outage, constraint or curtailment in operation would be excused by reason of Force Majeure as defined in this EPA.".

17. Subsection 18.1(c) is amended by adding the words "or the Private Line" after the words "Seller's Plant".

18. Appendix 1 is amended by:

(a) adding the following definitions:

"**Private Line**" means the line owned by _______________ as at the Effective Date extending from ________________ to the Transmission System as indicated on Schedule 1 to Appendix 5. ***[Note to Bidders: The blanks in this section will be completed based on the information contained in the Bidder's Tender as supplemented, as required, by information provided by the Transmission Authority.]***

"**Private Line Agreement**" means the agreement between the Seller and the Private Line Owner pursuant to which the Seller is authorized to transmit Energy from the Seller's Plant along the Private Line to the POI.

"**Private Line Owner**" means the owner of the Private Line from time to time.

(b) amending subsection (c) of the definition of "**Buyer Termination Event**" by adding the words "or the Private Line Owner" after the word "Seller" wherever that word appears in that subsection;

(c) amending the definition of "**Combined Study Agreement**" by adding the words "or the Private Line Owner" after the word "Seller";

(d) amending the definition of "**Facilities Agreement**" by adding the words "or the Private Line Owner" after the word "Seller";

(e) amending subsection (f) in the definition of "**Force Majeure**" by deleting everything from the words "and such delay" to the end of the subsection and replacing them with the following:

"and such delay is not attributable to the Seller or the Seller's Plant or to the Private Line Owner or any of the Private Line Owner's facilities, including any change to the point of interconnection with the Transmission System or other Project change made by the Seller or the Private Line Owner as described in section 4.5";

(f) amending the definition of "**Interconnection**" by adding the words "along the Private Line" after the words "Seller's Plant";

(g) amending the definition of "**Interconnection Agreement**" by adding the words "or the Private Line Owner" after the word "Seller";

(h) deleting the definition of "**POI**" and replacing it with the following:

"**POI**" or "**Point of Interconnection**" means _________________. ***[Note to Bidders – This will be the point of interconnection between the Private Line and the Transmission System. This blank will be completed based on the information in the Bidder's Tender as supplemented, as required, by information provided by the Transmission Authority.]***

(i) amending the definition of "**Project Assets**" by adding the words "and all agreements with the Private Line Owner" at the end of the definition; and

(j) amending the definition of "**Seller's Plant**" by adding the words "but excluding the Private Line" at the end of the definition.

19. Section 3 of Appendix 4 is amended by:

(a) adding the words "or the Private Line Agreement" at the end of the second sentence of that section; and

(b) adding the following sentence at the end of section 3:

"The Private Line Owner is not in material default under the Interconnection Agreement or the Facilities Agreement".;

20. If Part A of Appendix 10 is applicable, Section 7.2 as amended by Part A is amended by adding the following as subsection (d) and by changing the period at the end of subsection (c) to a semicolon and adding the word "and" at the end of subsection (c):

"(d) the Seller has entered into an agreement with the Private Line Owner amending the Private Line Agreement as required to accommodate the increase or decrease in the Hourly Firm Energy Amount and has provided a copy of the amending agreement to the Buyer (with any confidential information redacted) or has provided evidence satisfactory to the Buyer, acting reasonably, that no such amendments are required."

21. If Part E of Appendix 10 is applicable, the definition of "POI" in Part E of Appendix 10 will be applicable instead of the definition of "POI" set out in this Part G of Appendix 10.

PART H – INTENTIONALLY DELETED

PART I - SPLIT BIDS

This Part applies to Bidders that tender only a portion of the output from the Seller's Plant to BC Hydro.

A. MONTHLY FIRM PROJECTS

1. Section 3.3 is amended by deleting the words "Plant Capacity" and replacing them with "highest Split Bid Threshold Level set out in Appendix 2."

2. The text of section 4.2 is deleted and replaced with the words "Intentionally Deleted" and all references to section 4.2 in any other section of the EPA are deleted.

3. Section 4.5 is amended by adding the words "(including any increase in the Project size)" after the words "Transmission Authority" in the second sentence of that section.

4. The following section is added as section 4.6:

   "**4.6 Network Upgrade Cost Allocation -** Regardless of how the Transmission Authority allocates Network Upgrade Costs as between the Buyer and the Seller, the Seller and the Buyer agree that the Buyer shall be responsible for that amount of the Network Upgrade Costs that is determined by multiplying the Network Upgrade Costs by an amount equal to the average of the Split Bid Threshold Levels divided by the Plant Capacity. The Seller shall be responsible for, and shall promptly reimburse the Buyer for, any Network Upgrade Costs in excess of the Network Upgrade Costs for which the Buyer is responsible pursuant to this section."

5. Subsection 5.2(b) is amended by deleting the words "Plant Capacity multiplied by 1 hour" and replacing them with "highest Split Bid Threshold Level set out in Appendix 2 multiplied by 1 hour".

6. Section 6.4 is amended by adding the following at the end of that section: "Notwithstanding anything in this section, the Buyer will not be required to reimburse or otherwise compensate the Seller for any impact on sales of Energy to third parties resulting from a requirement to reschedule a Planned Outage in accordance with this section."

7. Section 7.2 is amended by:

   (a) deleting the words "Plant Capacity multiplied by the number of hours in the applicable month" in subsection 7.2(b) and replacing them with "Split Bid Threshold Level for the applicable month" and

   (b) adding the following sentence at the end of that section:

   "If the Seller delivers a notice to increase or decrease the Monthly Firm Energy Amount pursuant to this section, the Seller may at the same time elect to increase or decrease the corresponding Split Bid Threshold Level by a percentage corresponding to the percentage increase or decrease in the Monthly Firm Energy Amount and in that event the amendment to Appendix 2 referred to above will include an amendment to the Split Bid Threshold Level set out in that Appendix."

8. Section 7.5 is deleted and replaced with the following:

"**7.5 Exclusivity -** The Seller shall not at any time during the Term commit, sell or deliver any Energy to any Person, other than the Buyer under this EPA, except for:

(a) Pre-COD Energy sold to third parties in accordance with section 7.1;

(b) during any period in which the Buyer is in breach of its obligations under section 7.4;

(c) during any period in which the Buyer is not accepting deliveries of Energy from the Seller due to Force Majeure invoked by the Buyer; and

(d) Energy, if any, in excess of the Split Bid Threshold Level.

From and after COD, the Seller shall not commit, sell or deliver any Energy to any Person at any time, unless the Metered Energy at that time exceeds the Split Bid Threshold Level and in that case, the Seller may only sell to third Persons that portion of Metered Energy that exceeds the Split Bid Threshold Level. All sales to third Persons authorized under this section shall be contracted in a manner that is consistent with the Seller's obligations and the Buyer's rights under this EPA. Any such sales will be subordinated in priority of delivery and in all other respects to the Buyer's rights to receive Energy from the Seller's Plant."

9. Section 7.9 is amended by deleting the words "Plant Capacity" in that section and replacing them with "Split Bid Threshold Level".

10. Section 12.5 is amended by adding the words "4.6" after "4.5" in that section, and by deleting the words "4.2,".

11. Section 13.3 is amended by adding the words "4.6" after "4.5" in that section, and by deleting the words "4.2,".

12. Section 15.3(a) is amended by adding "4.6," after "4.5," in that section, and by deleting the words "4.2,".

13. Section 15.4(a) is amended by deleting the words "Plant Capacity" and replacing them with "highest Split Bid Threshold Level set out in Appendix 2".

14. Subsection 15.5(d)(i) is deleted and replaced with the following:

"(i) 115% of the amount determined by multiplying the Development Costs by an amount equal to the average of the Split Bid Threshold Levels divided by the Plant Capacity; and".

15. The definition "**Eligible Energy**" in Appendix 1 is deleted and replaced with the following:

"**Eligible Energy**" means in each month after COD:

(a) the amount of Metered Energy delivered by the Seller at the POI in that month; and

(b) Energy that is deemed to be "Eligible Energy" in that month pursuant to section 7.9,

but excluding all Metered Energy that exceeds the Split Bid Threshold Level.

16. The definition of "**Major Damage**" in Appendix 1 is deleted and replaced with the following:

"**Major Damage**" means damage where the cost to repair or rebuild the Seller's Plant with a Plant Capacity equivalent to the highest Split Bid Threshold Level exceeds the present value (using the Present Value Rate) of (a) the projected Energy deliveries from the Seller's Plant for the remainder of the Term (not exceeding the Split Bid Threshold Levels), multiplied by (b) the projected payments under this EPA for that Energy, (calculated on the basis that the Tier 2 Non-Firm Energy Price will be equal to the Tier 1 Non-Firm Energy Price), less a $/MWh amount determined by multiplying the estimated operating and maintenance costs for the Seller's Plant (including costs of the Energy Source) by an amount equal to the average of the Split Bid Threshold Levels divided by the Plant Capacity.

17. The definition of "**Plant Capacity**" in Appendix 1 is amended by deleting the words "as amended in accordance with section 4.2".

18. The definition of "**Performance Security**" in Appendix 1 is amended by deleting the words "Plant Capacity" and replacing them with "highest Split Bid Threshold Level set out in Appendix 2".

19. The definition of "**Pre-COD Energy**" in Appendix 1 is deleted and replaced with the following:

"**Pre-COD Energy**" means that amount of Metered Energy delivered by the Seller at the POI prior to COD including Test Energy, but excluding any portion of the Metered Energy that exceeds the Split Bid Threshold Level."

20. Appendix 1 is amended by adding the following definition:

"**Split Bid Threshold Level**" means the level of Energy output as set out in Appendix 2 that the Seller is required to deliver to the Buyer after COD before the Seller can sell any Energy to third parties.

21. The definition of "**Test Energy**" in Appendix 1 is deleted and replaced with the following:

"**Test Energy**" means Metered Energy delivered to the POI during any successful test pursuant to subsection 5.2(b), but excluding any portion of the Metered Energy that exceeds the Split Bid Threshold Level.

22. Section 4 in Appendix 3 is amended by:

(a) deleting the first formula in that section and replacing it with the following:

"$X_n * [(TRl_n * AVl_n) + (TRi_n * AVi_n)] > X_{COD} * [(TRl_{COD} * AVl_{COD}) + (TRi_{COD} * AVi_{COD})]$",

(b) deleting the second formula and replacing it with the following:

"Payment Amount = X_n multiplied by (the greater of (i) 0 and (ii) the amount determined in accordance with the following formula: $\{[(TRl_n - TRl_{COD})* AVl_n] + [(TRi_n - TRi_{COD}) *AVi_n]\} * 0.5)$"; and

(c) inserting the following under the term "Where":

"X_n = the average of the Split Bid Threshold Levels divided by the Plant Capacity in year n".

23. If Part B of Appendix 10 is applicable, the definition of "Green Attributes" is amended by deleting the word "Energy" in subsections (a) and (b) and replacing it with "Energy but not exceeding the Split Bid Threshold Level".

B. HOURLY FIRM PROJECTS

The following changes apply to Projects that tender an hourly firm split bid project in addition to the changes in Part A of Appendix 10, Part I.

24. Section 4.6, as added by Part A of this Appendix, is amended by adding the word "weighted" before the word "average", and by inserting the words "(using the Table in Part 2 of Appendix 2)" after the word "average".

25. Section 7.2 is amended by:

(a) deleting the words "Plant Capacity multiplied by the number of hours in the applicable month" in subsection (b) and replacing them with "Split Bid Threshold Level for the applicable hour"; and

(b) deleting the last sentence of that section (as amended by Part A of Appendix 10, Part I) and replacing it with the following:

"If the Seller delivers a notice to increase or decrease any Hourly Firm Energy Amount pursuant to this section, the Seller may at the same time elect to increase or decrease the corresponding Split Bid Threshold Level by a percentage corresponding to the percentage increase or decrease in the Hourly Firm Energy Amount and in that event the amendment to Appendix 2 referred to above will include an amendment to the Split Bid Threshold Level set out in that Appendix."

26. Subsection 15.5(d)(i), as amended by Part A of this Appendix, is amended by inserting the word "weighted" before the word "average", and by inserting the words "(using the Table in Part 2 of Appendix 2)" after the word "average".

27. Section 4 of Appendix 3, as amended by Part A of this Appendix, is amended in the definition of "X_n" by inserting the word "weighted" before the word "average", and by inserting the words "(using the Table in Part 2 of Appendix 2)" after the word "average".

PART J - SELLER IS A JOINT VENTURE OR GENERAL PARTNERSHIP

This Part applies if the Seller is a joint venture or general partnership.

1. Section 1.12 is added as follows:

   1.12 Joint and Several Liability - Each of [Partner1] and [Partner2] are jointly and severally, and not severally only, liable to the Buyer for and in respect of all liabilities and obligations of the Seller under or in relation to this EPA. All references to the "Seller" herein mean both [Partner1] and [Partner2], unless the contrary is expressly indicated. Acts or omissions of either [Partner1] or [Partner2] in relation to this EPA are deemed to be acts or omissions of the Seller.

2. Section 6.7 is deleted and replaced with the following:

   Neither the Seller nor [Partner1] or [Partner2] shall take any action that would cause the Seller, [Partner1] or [Partner2] to cease to be exempt, or omit to take any action necessary for the Seller, [Partner 1] and [Partner 2] to continue to be exempt, from regulation as a "public utility", as defined in the UCA, with respect to the Seller's Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA where such designation as a "public utility" could reasonably be expected to have an adverse effect on the Buyer or its interests under this EPA.

3. Section 16.1 is deleted and replaced with the following:

   A Party, which in the case of the Seller, includes any or all of the Seller, [Partner1] and [Partner2], may not assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term except:

   (a) with the consent of the other Party, such consent not to be unreasonably withheld, delayed or conditioned; or

   (b) to an Affiliate, on notice to, but without the consent of, the other Party, provided that the assignor will remain liable for the obligations of the assignee under this EPA, unless otherwise agreed in writing by the other Party.

   Notice of intent to assign, and where applicable a request for consent to assign, must be given by the assignor to the other Party not less than 30 days before the date of assignment, and, except in the case of assignment to a Facility Lender, must be accompanied by a proposed form of assignment and assumption agreement, and, in the case of an assignment pursuant to subsection 16.1(a), other than to a Facility Lender, evidence of the capability of the assignee as required by subsection 16.2(b). Consent to an assignment to a Facility Lender will not be given or be deemed to be given until full execution and delivery of the agreement contemplated by section 16.3. Any sale or other disposition of all or a substantial part of the Seller's, [Partner1]'s or [Partner2]'s ownership interest, in the Seller's Plant, or of all or any interest of the Seller, [Partner1] or [Partner2] in this EPA or revenue derived from this EPA, and any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's, [Partner1]'s or [Partner2]'s ownership interest in the Project Assets and any change of Control, merger, amalgamation or reorganization of the Seller, [Partner1] or [Partner2] is deemed to be an assignment of this EPA by the Seller for the purpose of this Article 16, including section 16.2, provided that where Control is transferred to an Affiliate or where the Seller or [Partner1] or [Partner2] merges or amalgamates with an Affiliate or enters into a reorganization with an Affiliate, subsection 16.1(b) shall apply.

4. Subsection 16.2(b) is deleted and replaced with the following:

(b) except for an assignment under subsection 16.1(b), the assignee demonstrating to the reasonable satisfaction of the other Party its capability (financial, technical and otherwise) to fulfil the obligations of the assignor under this EPA or, in the case of a change of Control, merger, amalgamation or reorganization of the Seller, [Partner1] or [Partner2], the parties to that transaction demonstrating to the reasonable satisfaction of the Buyer, the continued ability of the Seller to perform its obligations under this EPA and, in the case only of an assignment of 100% of the assignor's interest in the Project Assets, the Seller's Plant, or this EPA or revenue derived from this EPA, upon such demonstration and concurrently with the agreement providing for the assumption of liabilities and obligations and the provision of Performance Security required under subsection 16.2(a), the assignor shall be released from all future obligations and liabilities under the EPA and the Performance Security provided by it will be returned or released.

5. Section 16.6 is deleted and replaced with the following:

Notwithstanding subsection 16.1(a), the Seller, [Partner1] or [Partner2] shall not assign (including any event or action that is deemed under section 16.1 to be an assignment) or otherwise dispose of any interest in this EPA prior to COD, except: (i) to an Affiliate as permitted under subsection 16.1(b); (ii) to a Facility Lender as permitted under subsection 16.1(a) and section 16.3; or (iii) with the prior consent of the Buyer, which consent may be given, withheld or conditioned in the unfettered discretion of the Buyer.

6. Section 18.1 is deleted and replaced with the following: The Seller and each of [Partner1] and [Partner2] as to itself only, represent and warrant to the Buyer, and acknowledge that the Buyer is relying on those representations and warranties in entering into this EPA, as follows:

(a) Corporate Status - Each of [Partner1] and [Partner2] are duly incorporated, organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation, is registered or otherwise lawfully authorized to carry on business in British Columbia, and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and to perform its obligations under this EPA;

(b) Bankruptcy - No actions have been taken or authorized by either [Partner1] or [Partner2] or any other Person to initiate proceedings for, or in respect of, the bankruptcy, insolvency, liquidation, dissolution or winding-up of the Seller or either [Partner1] or [Partner2] or to appoint a receiver, liquidator, trustee or assignee in bankruptcy in respect of the Seller or either [Partner1] or [Partner2];

(c) Assets - No appropriation, expropriation or seizure of all or any portion of the Seller's Plant is pending or threatened;

(d) No Conflict - Neither the signing of this EPA nor the carrying out of the Seller's obligations under this EPA will: (i) constitute or cause a breach of, default under, or violation of, the constating documents or bylaws of either [Partner1] or [Partner2], any permit, franchise, lease, license, approval or agreement to which [Partner1] or [Partner2] is a party, or any other covenant or obligation binding on the Seller or either [Partner1] or [Partner2] or affecting any of their properties; (ii) cause a lien or encumbrance to attach to the Seller's Plant, other than a security interest granted in respect of financing the design, construction or operation of the Seller's Plant; or (iii) result in the acceleration, or the right to accelerate, any obligation under, or the termination of, or the right to terminate, any permit, franchise, lease, license, approval or agreement related to the Seller's Plant;

(e) Binding Obligation - This EPA constitutes a valid and binding obligation of Seller, [Partner1] and [Partner2] enforceable against Seller, [Partner1] and [Partner2] in accordance with its terms;

(f) Authorization, Execution and Delivery - This EPA has been duly authorized, executed and delivered by [Partner1] and [Partner2];

(g) Bid Documents - All material information in the Bid Documents is true and correct in all material respects and there is no material information omitted from the Bid Documents which makes the information in the Bid Documents misleading or inaccurate in any material respect; and

(h) Exemption from Regulation - The Seller, [Partner 1] and [Partner 2] are exempt from regulation as a "public utility" as defined in the UCA with respect to the Seller's Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA.

7. Section 19.1 is amended by:

(a) adding the words "and [Partner 1] and [Partner 2]" after the word "Seller" in the first line in that section; and

(b) adding the words "or [Partner 1] or [Partner 2]" after the word "Seller" in all other places where the word "Seller" appears in that section.

8. Section 19.2 is amended by replacing the words "the Seller" with the words "the Seller [Partner 1] and [Partner 2]" in the first line thereof.

9. The definition of "**Affiliate**" in Appendix 1 is deleted and replaced with the following:

"**Affiliate**" means, with respect to the Seller, [Partner1] or [Partner2] any Person directly or indirectly Controlled by, Controlling, or under common Control with, the Seller, [Partner1] or [Partner2] and with respect to the Buyer, any Person directly or indirectly Controlled by the Buyer and, if at any time the Buyer is not Controlled, directly or indirectly by the Province of British Columbia, shall include any Person directly or indirectly Controlling, or under common Control with, the Buyer.

10. The definition of "**Bankrupt or Insolvent**" in Appendix 1 is amended by adding the following after the word "Person" in the first line of that definition: "(which in the case of the Seller includes any or all of the Seller, [Partner1] or [Partner2])".

11. Subsection (a) of the definition of "Buyer Termination Event" in Appendix 1 is deleted and replaced with the following:

"(a) any one of the Seller, [Partner1] or [Partner2] is Bankrupt or Insolvent";

12. The words "the Seller is in material default" in subsection (e) of the definition of "Buyer Termination Event" in Appendix 1 are deleted and replaced with the following:

    "any one of the Seller, [Partner 1] or [Partner 2] is in material default"

13. The definition of "**COD Certificate**" in Appendix 1 is amended by adding the following after the words "officer of":

    "each of [Partner1] and [Partner2] and".

14. Note to Bidders: The description of the Parties on page 1 of the EPA and the signature block will be amended as necessary to reflect the general partnership or joint venture structure.

PART K - SELLER IS A LIMITED PARTNERSHIP

This Part applies if the Seller is a limited partnership.

1. Section 1.12 is added as follows:

1.12 **General Partner -** All references to the "Seller" herein include [General Partner(s)], unless the contrary is expressly indicated. Acts or omissions of [General Partner(s)] in relation to this EPA are deemed to be acts or omissions of the Seller.

[Note to Bidders: Where there is more than one General Partner the following will be added at the end of section 1.12:

Each of [General Partner 1] and [General Partner 2] are jointly and severally, and not severally only, liable to the Buyer for and in respect of all liabilities and obligations of the Seller under or in relation to this EPA.]

2. Section 6.7 is deleted and replaced with the following:

Neither the Seller nor [General Partner(s)] shall take any action that would cause the Seller or [General Partner(s)] to cease to be exempt, or omit to take any action necessary for the Seller and the [General Partner(s)] to continue to be exempt, from regulation as a "public utility", as defined in the UCA, with respect to the Seller's Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA where such designation as a "public utility" could reasonably be expected to have an adverse effect on the Buyer or its interests under this EPA.

3. Section 16.1 is deleted and replaced with the following:

A Party, which in the case of the Seller includes any or all of the Seller and General Partner(s), may not assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term except:

(a) with the consent of the other Party, such consent not to be unreasonably withheld, delayed or conditional; or

(b) to an Affiliate, on notice to, but without the consent of, the other Party, provided that the assignor will remain liable for the obligations of the assignee under this EPA, unless otherwise agreed in writing by the other Party.

Notice of intent to assign, and where applicable a request for consent to assign, must be given by the assignor to the other Party not less than 30 days before the date of assignment, and, except in the case of assignment to a Facility Lender, must be accompanied by a proposed form of assignment and assumption agreement, and, in the case of an assignment pursuant to subsection 16.1(a), other than to a Facility Lender, evidence of the capability of the assignee as required by subsection 16.2(b). Consent to an assignment to a Facility Lender will not be given or be deemed to be given until full execution and delivery of the agreement contemplated by section 16.3. Any sale or other disposition of all or a substantial part of the Seller's or [General Partner(s)]'s ownership interest in the Seller's Plant, or of all or any interest of the Seller or [General Partner(s)] in this EPA or revenue derived from this EPA, and any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's or [General Partner(s)]'s ownership interest in the Project Assets and any change of Control, merger, amalgamation or reorganization of the Seller or [General Partner(s)] is deemed to be an assignment of this EPA by the Seller for the purpose of this Article 16, including section 16.2, provided that where Control is transferred to an Affiliate or where the Seller or [General Partner(s)] merges or amalgamates with an Affiliate or enters into a reorganization with an Affiliate, subsection 16.1(b) shall apply.

4. Subsection 16.2(b) is deleted and replaced with the following:

(b) except for an assignment under subsection 16.1(b), the assignee demonstrating to the reasonable satisfaction of the other Party its capability (financial, technical and otherwise) to fulfil the obligations of the assignor under this EPA or, in the case of a change of Control, merger, amalgamation or reorganization of the Seller or [General Partner(s)], the parties to that transaction demonstrating to the reasonable satisfaction of the Buyer, the continued ability of the Seller to perform its obligations under this EPA and, in the case only of an assignment of 100% of the assignor's interest in the Project Assets, the Seller's Plant, or this EPA or revenue derived from this EPA, upon such demonstration and concurrently with the agreement providing for the assumption of liabilities and obligations and the provision of Performance Security required under subsection 16.2(a), the assignor shall be released from all future obligations and liabilities under the EPA and the Performance Security provided by it will be returned or released.

5. Section 16.6 is deleted and replaced with the following:

Notwithstanding subsection 16.1(a), the Seller or [General Partner(s)] shall not assign (including any event or action that is deemed under section 16.1 to be an assignment) or otherwise dispose of any interest in this EPA prior to COD, except: (i) to an Affiliate as permitted under subsection 16.1(b); (ii) to a Facility Lender as permitted under subsection 16.1(a) and section 16.3; or (iii) with the prior consent of the Buyer, which consent may be given, withheld or conditioned in the unfettered discretion of the Buyer.

6. Section 18. 1 is deleted and replaced with the following:

The Seller and each [General Partner(s)] as to itself only represent and warrant to the Buyer, and acknowledge that the Buyer is relying on those representations and warranties in entering into this EPA, as follows:

(a) Corporate Status - As to the [General Partner(s)], it is duly incorporated, organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation, is registered or otherwise lawfully authorized to carry on business in British Columbia, and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and to perform its obligations under this EPA. As to the Seller, it is duly created and organized, validly existing and in good standing under the laws of the jurisdiction of its creation, is registered or otherwise lawfully authorized to carry on business in British Columbia and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and perform its obligations under this EPA;

(b) Bankruptcy - No actions have been taken or authorized by the Seller or [General Partner(s)] or any other Person to initiate proceedings for, or in respect of, the bankruptcy, insolvency, liquidation, dissolution or winding-up of the Seller or [General Partner(s)] or to appoint a receiver, liquidator, trustee or assignee in bankruptcy in respect of the Seller or [General Partner(s)];

(c) Assets - No appropriation, expropriation or seizure of all or any portion of the Seller's Plant is pending or threatened;

(d) No Conflict - Neither the signing of this EPA nor the carrying out of the Seller's obligations under this EPA will: (i) constitute or cause a breach of, default under, or violation of, the constating documents or bylaws of the Seller or [General Partner(s)], any permit, franchise, lease, license, approval or agreement to which the Seller or [General Partner(s)] is a party, or any other covenant or obligation binding on the Seller or [General Partner(s)] or affecting any of their properties; (ii) cause a lien or encumbrance to attach to the Seller's Plant, other than a security interest granted in respect of financing the design, construction or operation of the Seller's Plant; or (iii) result in the acceleration, or the right to accelerate, any obligation under, or the termination of, or the right to terminate, any permit, franchise, lease, license, approval or agreement related to the Seller's Plant;

(e) Binding Obligation - This EPA constitutes a valid and binding obligation of the Seller and [General Partner(s)] enforceable against the Seller and [General Partner(s)] in accordance with its terms;

(f) Authorization, Execution and Delivery - This EPA has been duly authorized, executed and delivered by the [General Partner(s)] on behalf of the Seller;

(g) Bid Documents - All material information in the Bid Documents is true and correct in all material respects and there is no material information omitted from the Bid Documents which makes the information in the Bid Documents misleading or inaccurate in any material respect; and

(h) Exemption From Regulation - The Seller and [General Partner(s)] are exempt from regulation as a "public utility" as defined in the UCA with respect to the Seller's Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA.

7. Section 19.1 is amended by:

(a) adding the words "and [General Partner(s)]"after the word "Seller" in the first line in that section; and

(b) adding the words "or [General Partner(s)]" after the word "Seller" in all other places where the word "Seller" appears in that section.

8. Section 19.2 is amended by replacing the words "the Seller" with the words "the Seller and the [General Partner(s)]" in the first line thereof.

9. The definition of "**Affiliate**" in Appendix 1 is deleted and replaced with the following:

"**Affiliate**" means, with respect to the Seller or [General Partner(s)] any Person directly or indirectly Controlled by, Controlling, or under common Control with, the Seller or [General Partner(s)] and with respect to the Buyer, any Person directly or indirectly Controlled by the Buyer and, if at any time the Buyer is not Controlled, directly or indirectly by the Province of British Columbia, shall include any Person directly or indirectly Controlling, or under common Control with, the Buyer.

10. The definition of "**Bankrupt or Insolvent**" in Appendix 1 is amended by adding the following after the word "Person" in the first line of that definition: "(which in the case of the Seller includes any or all of the Seller or [General Partner(s)])"

11. Subsection (a) of the definition of "Buyer Termination Event" in Appendix 1 is deleted and replaced with the following:

    "(a) any one of the Seller or [General Partner(s)] is Bankrupt or Insolvent";

12. The words "the Seller is in material default" in subsection (e) of the definition of "Buyer Termination Event" in Appendix 1 are deleted and replaced with the following:

    "any one or all of the Seller, or [General Partner(s)] is in material default"

13. The definition of "**COD Certificate**" in Appendix 1 is amended by adding the following after the words "officer of":

    "each [General Partner(s)] and".

14. Note to Bidders: The description of the Parties on page 1 of the EPA and the signature block will be amended as necessary to reflect the limited partnership structure.

PART L – INTENTIONALLY DELETED

ISSUE: **Interconnection Agreement**

REFERENCE: **Application, page 8, PDF page 11**

QUOTE: "The Project will also include upgrades as required to connect the THELP's Plant to the YIS (defined in the EPA as "Buyer-AEY System" and "Buyer-AEY System Upgrades"). Final scoping for these upgrades (with planning level cost estimates) is to be included in the Buyer-AEY System Interconnection Study Report that is currently being concluded as part of the Interconnection Agreement between THELP, YEC and AEY."

QUESTION:

a) When is the Buyer-AEY System Interconnection Study Report due, and when will those costs be known?

b) Is there a cost threshold for this part of the project at which the project will not be viable or otherwise not proceed?

c) From the Yukon/BC border to Jakes Corner, how many potential electricity users will connect to the system?

d) Are those users customers of THELP or YEC?

e) What First Nation settlement lands and traditional territories would be affect b [sic] the Atlin-Jakes Corner infrastructure, and what is the extent of consultation/accommodation to date?

ANSWER:

(a)

The Buyer-AEY System Interconnection Study report forms part of the Interconnection Agreement. The Condition Precedent date for the Interconnection Agreement to be executed has been extended to March 31, 2022. Please see response to YUB-YEC-1-9(a) for current information on system upgrades and related cost estimates.

(b)

No cost threshold has been specified by THELP for these YEC and AEY system upgrades.

(c) and (d)

No electricity users will connect to the system from the line to be developed and owned by THELP between the Yukon/BC border to Jakes Corner.

(e)

The THELP owned and developed Project facilities in Yukon between the BC/Yukon border and Jakes Corner are in the traditional territory of the Carcross Tagish First Nation, but do not affect any First Nation settlement lands.

Project facilities in British Columbia are in the traditional territory of the Taku River Tlingit First Nation.

THELP is responsible for consultation/ accommodation related to the Project. YEC is not able to advise on the specifics to date regarding these activities.

ISSUE: **Dependable Plant Capacity Tests**

REFERENCE: **Application, page 9, PDF page 12**

QUOTE: "Dependable Plant Capacity Tests at THELP's COD - overall Phase One and Phase Two Dependable Plant Capacity delivered to YEC at the POI, as confirmed by these tests, cannot be less than 8.0 MW and not more than 8.5 MW."

QUESTION:

a) Please explain the significance of the upper limit of 8.5 MW.

ANSWER:

(a)

An upper limit was set to ensure that the plant could be operated during the Peak Winter Period as required to provide dependable capacity, given information on available water availability as reviewed in Tables A1and A2 of the Submission. If for some reason THELP had opportunity to provide a higher delivered capacity, an amendment of this provision would be required – and any such amendment would depend on THELP confirming that the Atlin plant could be operated during the Peak Winter Period as required to provide dependable capacity, given information on water availability.

ISSUE: **Notice of first Peak Winter Period (PWP)**

REFERENCE: **Application, pages 9-10, PDF pages 12-13**

QUOTE: "If THELP is unable to confirm to YEC on or before June 1, 2024 the availability of Dependable Plant Capacity for the first PWP, Section 4.3 of the EPA provides that YEC may proceed to rent diesel generating units for this first PWP and no Dependable Capacity Payment will be payable by YEC to THELP for the first PWP for Dependable Plant Capacity that was already provided by such rented diesels."

QUESTION:

a) How will YEC determine the number of diesel generation units that are required to be rented in the situation referenced in the above quote?

ANSWER:

(a)

Assuming that rented diesel units are 1.8 MW capacity per unit, the number of additional required diesel rental units will be determined by adding the non-available Dependable Plant Capacity under the EPA to the N-1 capacity shortfall that otherwise would be forecast for the PWP and dividing the adjusted shortfall by 1.8 MW (and assuming one rental unit is needed for any resulting fraction).

ISSUE: **Operating rules**

REFERENCE: **Application, page 10, PDF page 13**

QUOTE: "Operating Rules for Seller's Plant (Schedule D of EPA) - require THELP and YEC to coordinate and schedule the delivery of Delivered Energy and Dependable Plant Capacity, subject to provisions affecting operations after each August until the start of the following June that are focused on maximizing hydro storage and its use at YEC's direction for dependable capacity during the PWP while recognizing constraints on changes to winter flows in the 7.8 km power canal due to ice conditions and/or water availability."

QUESTION:

a) Please provide the details and principles YEC will use in determining its merit order for dispatching generation.

b) Where will the Atlin hydro expansion project's electricity be placed in the merit order?

ANSWER:

(a) and (b)

IPP contracts are take-or-pay arrangements; therefore, IPP contracts are dispatched first in the generation stacking order, followed by YEC hydro and thermal assets. Note that the Atlin plant is intended to be shut down for the summer months, unless YEC specifically requests summer energy (which would only happen when thermal generation was otherwise expected on the YIS).

ISSUE: **Commercial terms**

REFERENCE: **Application, page 11, PDF page 14**

QUOTE: "2. Payment for Winter Energy that displaces forecast thermal generation: YEC will only pay for winter energy based on its displacement of YEC's forecast thermal fuel generation costs at long-term average renewable sources for the YIS and the Project."

"3. Delivery of all Winter Energy available: while YEC will only pay for winter energy that displaces LTA forecast thermal generation, YEC will take delivery each winter season (Sep-May) of all available energy that the Project is able to generate."

"4. Thermal Benchmark Pricing: the 2024 benchmark prices paid under the EPA are $0.19/kWh for energy that displaces thermal generation (based on blended thermal generation LNG and diesel fuel costs) and $200/kW per year for the levelized cost of capacity (capital and non-fuel O&M) of permanent new greenfield thermal generation assets. Benchmark prices after 2024 are assumed to escalate at 50% of CPI for energy and 100% of CPI for dependable capacity."

"5. Payment for Capacity: rather than paying for actual dependable capacity provided by the Project, YEC will pay for Dependable Plant Capacity Committed over each Peak Winter Period, based on the outcome of a capacity test completed each December at the beginning of each winter period. A mechanism is included for YEC to recoup any shortfalls in actual dependable capacity delivered each winter period through deductions from the additional revenue opportunities/upside opportunities for THELP (see item 7 below)."

QUESTION:

a) In paragraph 2 of the above quote, explain in detail what is meant by "forecast thermal fuel generation costs at long-term average renewable sources" and how it applies in the context of the quote.

b) How is the thermal displacement amount determined?

c) What happens if thermal fuel generation costs are lower than LTA?

d) What happens if thermal fuel generation costs are higher than LTA?

e) In paragraph 3 of the above quote, what are the implications of this provision relative to the amount of thermal generation that YEC would otherwise require during the winter months?

f) In paragraph 3 of the above quote, does the term “Delivery of all Winter Energy” create a situation where YEC will spill water at its own hydro facilities without generating electricity because it is taking energy based on the Atlin project?

g) Is the result that any energy delivered in excess of LTA forecast thermal generation will effectively be delivered at no cost?

h) In paragraph 4 of the quote above, does the blended LNG and diesel fuel costs for generation closely reflect the actual costs for usage of those generation sources?

i) Please file any existing documents relating to the costing model for permanent new greenfield thermal generation assets, including any form of business case analysis, including comparison with rented diesel generators.

j) Show detailed calculations of how the $0.19/kWh and $200/kW were derived. In the response, list all assumptions made in the calculations.

k) Why are benchmark prices assumed to escalate instead of relying on previous year escalation rates?

l) Is capacity considered a fixed cost? Please explain.

m) If capacity is considered a fixed cost, why is it escalated by CPI?

n) Explain why committed capacity is used and not actual capacity. Please explain why committed capacity is preferrable to actual capacity given, for example, that price and revenue would be more accurate using actual capacity.

o) How does the use of committed capacity benefit both YEC and Yukon ratepayers?

p) Does the mechanism in paragraph 5 result in any actual cash recovery from THELP (or deferral of YEC payments to THELP), and if so, what length of time would it take to recover any shortfalls?

ANSWER:

(a) through (p)

The question focuses on four specific "key principles" relevant to YEC as purchaser, as noted in Section 3.4.1 of the Submission. The principles guided the negotiation of the EPA commercial terms – however, specific questions as posed in this IR regarding EPA commercial terms require review of the EPA terms. The following response accordingly addresses the applicable EPA terms.

Energy Price and Payment for Delivered Energy during Winter Period

Questions (a) through (h) as well as (j and k) address principles and terms for the EPA energy price for delivered energy during the Winter Period.

Overall, in Principle 2 YEC required that EPA energy prices for winter period delivered energy be based on YEC forecast thermal fuel cost savings as assessed at long-term average (LTA) conditions for both the Atlin delivered energy and the other forecast YIS renewable generation sources.

In order to determine the required YEC thermal fuel cost savings, consistency is required with OIC 2021/16 direction that YEC's forecast fuel costs must be based on long term average renewable generation when setting YEC rates – and that variances in actual thermal generation from LTA thermal generation are to be addressed by a low water deferral account. In summary, YEC costs and rates for thermal generation are based on LTA renewable generation sources.

The forecast approach is also necessary to set EPA prices that will provide the Seller sufficient certainty on revenue to prove financial viability, i.e. this certainty is required now to ensure a "bankable" project.

Forecast thermal displacement volumes and costs (2024$) for 2024 load forecast and 2035 load forecast, at LTA Atlin deliveries and low water year deliveries, are provided in Table A3-1 of YEC's Submission. The volume of thermal displacement is calculated by modelling the YIS system using YECSIM to simulate thermal generation both with and without Atlin under 38 water years for 2024 and 2035 YIS forecast loads. The Table A3-1 process is summarized below using as an example Table A3-1 columns A and B dealing with the 2024 YIS load forecast:

- In Table A3-1 for the 2024 load forecast, the model estimates:
    - in column A that LTA winter deliveries of 30.8 GWh result in LTA thermal displacement of 19.583 GWh (displacement at 63.5% of EPA deliveries); and
    - In column B that low water year (i.e., firm) winter deliveries of 25.2 GWh result in LTA thermal displacement of 17.450 GWh (displacement at 69.2% of EPA deliveries).

- The estimated ratio is then applied in each column to the YEC forecast blended fuel cost of 19 cents per kWh to get (row 10) the EPA winter price of 12.1 cents/kWh for LTA deliveries and 13.2 cents/kWh for low water year (firm) deliveries.

- The EPA provides the “Firm” energy price (13.2 cents per kWh in column B) for the first 25.2 GWh delivered during winter in each calendar year.

- A “Non-firm” energy price (7.2 cents per kWh) is provided for the balance of the winter energy delivered in each calendar year (see Table A3-2, column A at row 11 for determination of this price – it is based on the LTA energy deliveries less the firm energy deliveries).

- Based on the assumptions as presented, YEC believes that this approach effectively ensures, within a reasonable range, that the utility will not pay for energy that does not offset forecast thermal displacement.

Based on these assessments, firm and non-firm EPA winter energy prices determination is provided in detail in Table A3-2 for two EPA time periods (2024-2034, and 2035 to the end of the EPA term). These 2024$ prices apply throughout the 40-year EPA term, subject (as is the case for SOP IPP prices) to annual escalation at 50% of CPI.

The response to YUB-YEC-1-13(a) provides the detailed calculations and assumptions regarding the (2024$) $0.19/kWh blend fuel price assumed for 2024 thermal energy displacement cost saving estimates. The 90%/10% assumed mix of LNG and diesel generation reflects YEC assumptions to date for GRA filings and is intended to reflect reasonably expected LTA thermal generation rather than actual generation in any specific year. Escalation of this forecast blend fuel energy price after 2024 at 50% of CPI reflects the same approach applicable to the SOP IPP price escalations.

Under Principle 3, YEC accepts that they will purchase all energy delivered during the Winter Period. The above Table A3-1 analysis shows how the EPA energy prices with this requirement are based on forecast LTA thermal displacement, taking into account purchased deliveries that do not displace thermal generation and increase water spill at YEC hydro facilities. See also YUB-YEC-1-11 and YUB-YEC-1-12 for additional analysis.

When coupled with the need to set EPA prices based on forecasts, there is cost risk created under Principle 3 because actual conditions will in all likelihood vary from the assumed forecasts. This risk is unlikely to result in material impact on YEC costs as supported in detail in Section 4.3 of YEC's Submission (see Operations, subsection 1 on Delivered Electricity at page 28 of the Submission). This conclusion reflects the ability to adjust YEC thermal generation in response to changes in Atlin deliveries, and the setting of the EPA price based on forecast thermal generation displaced (with firm and non-firm EPA prices that tend to reduce the cost impact of variances in EPA deliveries relative to the Atlin low water year).

Another risk is related to YIS loads, other renewable energy resources or fuel costs for thermal generation being different than assumes for setting EPA energy prices. These YIS forecast condition risks affect any new YEC resource commitment made for long-term energy generation supplies. Although such variances are likely, YEC's Submission (based on analysis provided at pages 28-29) that these risks only affect net YEC costs for the EPA relative to thermal energy generation, and remain reasonable in the context of YIS resource planning.

Dependable Capacity Price and Payment for PWP

Questions (i) through (p) address principles and terms for the EPA capacity price for dependable capacity provided during a Peak Winter Period (PWP).

The assumptions and references for the \$200/kW (2024\$) EPA capacity price determination based on levelized cost of capacity (LCOC) for new greenfield diesel are reviewed in detail in response to YUB-YEC-1-13(a). As reviewed in that response, the Board in its report on the BESS Project noted that rented diesels would not be a reliable way of closing the capacity shortfall gap. Rented diesel costs were therefore not considered in the setting of the EPA capacity price.

The LCOC cost benchmarks referenced for new greenfield diesel include capital and non-fuel O&M costs (i.e., fuel costs are excluded). In the case of an actual new diesel plant, once built and in-service the capital cost would be “fixed” and added to YEC rate base with annual depreciation and return on rate base expenses added to YEC annual costs – annual non-fuel operating costs, however, would vary and normally escalate over the years of operation. In contrast to such actual annual cost impacts from a new diesel plant, the LCOC benchmark established one present value amount per kW-yr for year 1 of operation to reflect estimated “real” (i.e., absent inflation) capital and non-fuel O&M over the life, and then assumes that this amount escalates at inflation over the project life.

The resulting LCOC amount per KW-yr was estimated starting in 2019 in the benchmark, and the estimate assumed escalation of this benchmark at CPI throughout the assumed life of the facility (as well as escalation as needed to adjust for an in-service date later than 2019). These factors explain why the EPA capacity price for 2024 assumed 2%/yr inflation escalation from 2019 to 2024, and also provided for ongoing escalation at CPI during the EPA term.

The concept of Dependable Plant Capacity Committed for determining initial payments was adopted as a result of negotiation to address the following considerations needed to allow the EPA to be concluded:

1. **Seller Financial Risk -** THELP required a firm capacity revenue amount for each year to assist in securing its financing, and was not prepared to proceed with these initial payments being subject to variance based on actual performance. THELP did agree, however, to the December capacity test for each year to confirm Dependable Plant Capacity Committed for each PWP based on this test. This measure addressed basic risks related to Seller Plant conditions over time.

2. **Operational Risk** - YEC’s review of available water (Tables A1 and A2 of Submission) as well as the EPA Operating Rules confirmed expected ability under all likely water conditions to secure the needed dependable capacity during the PWP. During a PWP it is possible that issues with the ice cover of the power canal or other brief disruptions affecting THELP’s Plant may result in short term disruptions to the delivery of dependable capacity. Such disruptions are not

expected to occur on any frequent basis, and would be unlikely to affect overall YIS service reliability unless they are concurrent with an N-1 event during a cold weather period.

In order to proceed, YEC secured the Dependable Capacity Excess Payment (DCEP) mechanism to recover excess Dependable Capacity Payments (DCP) due to shortfalls in actual dependable capacity delivered each PWP. Recoveries are contingent on THELP being eligible for additional payments in future years beyond the EPA prices – but YEC recoveries are to occur before any THELP additional payments would be made for higher-than-forecast loads after 2034 or any carbon tax charges applicable to YEC.

In summary, the use of committed capacity enabled all parties to proceed with work to advance the Project in order to secure the forecast benefits for both YEC (and ratepayers) and THELP.

The mechanism in Principle 5 in the referenced quote would reduce (rather than defer) YEC cash payments to THELP. YEC is not able to provide any assessments of time requirements, beyond noting that recoveries related to Additional Payments (linked to Added Load on the grid) cannot occur before 2035.

ISSUE: **Buyer-AEY System Constraint**

REFERENCE: **Application, page 12, PDF page 15**

QUOTE: "Buyer-AEY System Constraint - YEC will have no liability for a Buyer-AEY System Constraint, except for a Non-Permitted System Constraint as set out in Section 6.5 of the EPA, i.e., a continuous Buyer-AEY System Constraint which exceeds 30 minutes in duration and which is not caused by (a) Buyer-AEY Planned Outage, or (b) THELP, THELP's Plant, or anything on THELP's side of the POI. If a Non-Permitted System Constraint occurs (and no exemption specified in Section 6.5 applies), YEC will pay THELP (for each such impacted month) for the Monthly Constraint Energy calculated for the relevant month under Schedule F of the EPA."

QUESTION:

a) Please provide further explanation of when YEC will not be responsible for payment in the Buyer-AEY System Constraint in Article 6. In your response, provide a numerical example of how the Monthly Constraint Energy will be calculated.

b) In what circumstances will YEC pay for unplanned outages in THELP facilities through the Monthly Constraint Energy in Schedule F?

c) Would YEC be required to pay for energy not received under the Buyer-AEY System Constraint?

d) Would THELP have any financial liability to YEC for failing to deliver contracted energy due to reasons other than low water conditions? If not, what consequential impacts would there be for Yukon ratepayers?

ANSWER:

(a)

"Monthly Constraint Energy" as defined in Schedule F of the EPA only occurs when YEC is responsible for payment regarding a Non-Permitted System Constraint, i.e., there is no example possible of how the Monthly Constraint Energy would be calculated when YEC is not responsible for payment in the Buyer-AEY System Constraint in Article 6.

As defined in the EPA, a Buyer-AEY System Constraint “means any disconnection of Seller’s Plant from Buyer-AEY System, or any outage, suspension, constraint, or curtailment in the operation of Buyer-AEY System preventing or limiting deliveries of Delivered Energy at the POI or within the Buyer-AEY System or any direction from Buyer to Seller to reduce generation of Seller’s Plant as a result of any outage, suspension, constraint, or curtailment in the operation of the Buyer-AEY System.”

Section 6.5 provides that Buyer will have no liability for a Buyer-AEY System Constraint (or be in breach of Sections 6.3 or 8.2) unless it is a Non-Permitted System Constraint as defined in Section 6.5. To be a Non-Permitted System Constraint for which YEC will pay the Monthly Constraint Energy calculated for the relevant month under Schedule F, the Buyer-AEY System Constraint must:

- Prevent Seller to deliver Delivered Energy that Seller is permitted to deliver under this EPA.

- Be solely the result of a continuous Buyer-AEY System Constraint which exceeds 30 minutes in duration and is not caused by (a) Buyer-AEY Planned Outage, or (b) Seller, Seller’s Plant, or anything on Seller’s side of the POI.

- Not be subject to exemptions set out in Section 6.5 when Buyer will not be required to pay for any Monthly Constraint Energy[1].

An example of how the Monthly Constraint Energy will be calculated is provided below, based on an aggregate of the Constraint Shortfall Energy for each Non-Permitted System Constraint event during a month:

1. Assume 2 separate Non-Permitted System Constraint events occur as follows during the PWP month of January when continuous delivery at 8 MW full capacity

[1] Section 6.5 lists four subsection exemptions as subsections “c” through “f”, including Force Majeure, any period when Seller’s Plant would otherwise not have been operating, any period specified as a Seller’s Outage in any Outage Notice or a revised Outage Notice, or when the Non-Permitted System Constraint is the result of the operation of the Seller’s Plant in a manner inconsistent with Section 3.2 of the EPA.

has been planned throughout each day during each week pursuant to the Operating Rules:

a. Event #1: 1 hour when 8,000 kWh Delivered Energy was expected to be provided; and
b. Event #2: 100 hours when 800,000 kWh Delivered Energy was expected to be provided.

2. Assume that the following reductions in such expected Delivered Energy are reductions that Seller takes, or is reasonably able to take, in response to the Non-Permitted System Constraint events to reduce or shut down water deliveries in the Upper Powerhouse:
   a. Event #1: No such reductions.
   b. Event #2: Determination that in response to the Non-Permitted System Constraint the Seller was able to shut down water deliveries in the Upper Powerhouse after 48 hours (2 days), resulting is a reduction capability of 416,000 kWh = (800,000-48*8000).

3. The Monthly Constraint Energy for January will then equal 392,000 kWh based on the aggregate of the following Constraint Shortall Energy for the two Non-Permitted System Constraint events during the month:
   a. Event #1: Constraint Shortfall Energy equals 8,000 kWh = (8000-0)
   b. Event #2: Constraint Shortfall Energy equals 384,000 kWh = (800,000-416,000).

(b)

There are no circumstances related to Monthly Constraint Energy when YEC will pay for unplanned outages in THELP facilities. As reviewed in response to “a” above, Section 6.5 of the EPA specifically excludes consideration of events on the Seller’s side of the POI or the result of operation of Seller’s Plant in a manner inconsistent with Section 3.2 of the EPA.

(c)

Yes, provided that such energy qualifies as Monthly Constraint Energy (see “a” above - the example shows 392,000 kWh that would need to be paid for by YEC).

(d)

The question asks about “contracted energy”. Overall, the EPA does not generally impose financial liabilities (other than reduced payments for the reduced energy deliveries) on THELP for failure to deliver expected energy deliveries for reasons other than low water conditions.[2] As reviewed in section 4.3 of YEC’s Submission (under Operations, Delivered Energy), the risk of a material impact on YEC costs, customer rates or reliability of service to customers from actual EPA delivered energy being lower than expected deliveries is not considered likely.

[2] This response does not preclude potential financial liabilities related to a breach of EPA terms and conditions that result in reduced energy deliveries.

ISSUE: **Winter delivered energy**

REFERENCE: **Application, page 13, PDF page 16**

QUOTE: "Also, provisions for added payments related to winter delivered energy (subject to any reductions under Section 8.3 of the EPA) for the following possibilities where YEC and THELP will share added thermal cost saving benefits:

• Additional Payments starting in 2035 if there is Added Load on the YIS, i.e., load in excess of that assumed [with no industrial load] to determine the 2035 energy price.

• Carbon Charge Saving Payment if YUB approves a carbon charge in future to be included in customer rates."

QUESTION:

a) Please provide further details on what carbon charge YEC is contemplating and why a term in this agreement was required.

ANSWER:

(a)

A term in the EPA was requested by THELP to address the possible added value of Atlin energy deliveries (based on resulting YEC cost savings for displaced thermal generation) in the event that the YUB approves inclusion in YEC customer rates of a Carbon Charge related to YEC thermal generation.

The provision contemplates a carbon tax or other form of carbon charge being imposed on YEC fossil fuel use for its thermal (LNG and diesel) generation.

ISSUE: **Dependable Capacity Payment**

REFERENCE: **Application, page 13, PDF page 16**

QUOTE: "Dependable Capacity Payment (DCP): the DCP is the payment by YEC to THELP, based only on Dependable Plant Capacity Committed (DPCC) as provided for in annual test in December, and a Dependable Capacity Price of $200/KW per year16 (2024$) as escalated at CPI after 2024."

QUESTION:

a) Why is inflation being applied? How do fixed or sunk costs factor into the application of CPI after 2024?

ANSWER:

(a)

The application of inflation to the EPA capacity price (DCP) over the life of the EPA is necessary to ensure lifecycle costs (i.e., present value costs over the 40-year project life) are the same whether YEC owns the equivalent diesel asset or buys the capacity through this IPP.

The DCP is based on the LCOC benchmark is a levelized cost for an equivalent owned asset. This benchmark sets the EPA capacity price based on ratepayer costs if YEC developed a greenfield diesel plant – including ratepayer costs over the diesel plant project life for depreciation, return on rate base and non-fuel O&M costs. The LCOC benchmark provides a price per KW-yr in 2024$ (after escalation from 2019$ used for the earlier studies). The LCOC annual levelized cost for the diesel plant is lowest in year 1 and escalates at inflation over the 40-year life – this differs from normal rate base revenue requirement determinations for the same diesel plant non-fuel costs which are highest in year 1 (due to rate base return impact) and then decline over the 40-year life. However, the present value of these costs at the start of project operation is the same under the LCOC approach and the rate base approach, assuming YEC's weighted average cost of capital is used as the discount rate.

The LCOC when calculated includes capital costs per kW (i.e., sunk costs) as well as non-fuel O&M costs per kW that are assumed to escalate annually at inflation. This levelized cost assumes YEC ownership of the new diesel plant over a 40 year life. The LCOC converts the “sunk costs” for capital into a 2024$ levelized cost per kW-yr for the 40 year life that recovers depreciation and a rate base return assuming YEC’s weighted average cost of capital (WACC). This levelized cost in 2024$ in year 1 of operation yields an amount per kW that escalates at inflation over the 40 year assumed thermal plant life in order to yield the present value initial sunk costs plus the applicable YEC WACC (debt and equity return) on this rate base.

In summary, the LCOC benchmark assumes inflation at CPI to adjust the price for each subsequent year during the thermal plant life (or in this case during the term of the EPA). Therefore, in order to apply this benchmark to setting the EPA capacity price, it is necessary to escalate the price each year by CPI.

Please see response to YUB-YEC-1-24 (section on Dependable Capacity Price and Payment for PWP) for a more detailed response.

ISSUE: **Dependable Capacity Excess Payment**

REFERENCE: **Application, page 13, PDF page 16**

QUOTE: "Dependable Capacity Excess Payment (DCEP) Account as per Section 8.3 of EPA"

QUESTION:

a) Please provide further explanation of this account and how this account will operate.

b) Will regulatory approval from the Board be required for recovery of costs or payment of refunds for payments under the DCEP Account? If not, how will YEC customers be protected from adjustments of payments that are required under Section 8.3 of the EPA?

ANSWER:

(a)

A more detailed explanation of the DCEP Account is provided in Appendix B, section 4.1.2, subsection 3(b) (Dependable Capacity Excess Payment (DCSP). A sample calculation to show how this account is adjusted is provided in Schedule G of the EPA and a tabular summary of the example is provided in Tables A4-1 and A4-2 of YEC's Submission. See also response to YUB-YEC-1-24 (section on capacity price).

(b)

The DCEP Account only allows for YEC to recover overpayments already made to THELP, i.e., there is no ability for THELP to access this Account to secure any added payments from YEC.

The EPA does not require or provide for any YUB approval prior to YEC use of this Account to recover amounts from THELP (through allowed reductions in future amounts that YEC would otherwise be required to pay to THELP). As noted above, any YEC use of this Account would be for the ultimate benefit of YEC customers, subject to YUB review and approval of any required mechanism to allow the resulting cost savings to be reflected in customer rates.

ISSUE: **YIS system upgrades**

REFERENCE: **Application, page 15, PDF page 18**

QUOTE: "… the only utility assets being developed by YEC/AEY pursuant to the EPA are YIS system upgrades that are to be fully funded by the Project at no cost risk to the utilities."

QUESTION:

a) To YEC's knowledge, do AEY system upgrades include a change from the existing 38 kV line to a 69 kV line? Please provide evidentiary support as part of the response.

ANSWER:

(a)

The AEY system upgrades for the Atlin EPA retain the existing AEY line voltage at 34.5 kV. Please see response to YUB-YEC-1-9(a) for additional information on the AEY system upgrades.

ISSUE: **Thermal displacement**

REFERENCE: **Application, page 15, PDF page 18**

QUOTE: “The capability of the Project during the initial 40-year EPA operating term to displace thermal generation capacity and energy otherwise expected to be required on the YIS to supply forecast electric load.”

QUESTION:

a) Why was a term of 40 years chosen? In your response, please provide what YEC considers is a standard term (in years) of an EPA based on past YEC projects or other information.

b) Will this project displace any existing hydro facilities on the YIS, for any periods throughout the year?

ANSWER:

(a)

The EPA term of 40 years was selected based on the renewable source (hydro). The Yukon SOP EPA [see YUB-YEC-1-9(a), Attachment 1, Schedule B] provides for a term of up to 40 years for a hydro clean energy source, and is understood to reflect practice for IPP agreements in British Columbia.

(b)

Energy delivered from the Atlin EPA will result at times in increased spill at existing hydro facilities on the YIS. This outcome is expected to occur with all currently planned SOP EPAs connecting to the YIS. The Atlin EPA has adjusted the EPA energy price to take into account the expected degree of thermal generation displacement versus hydro generation displacement.

See response to YUB-YEC-1-11 and YUB-YEC-1-12 for more detailed review of how EPA energy prices were established in this regard.

ISSUE:

REFERENCE: **Application, page 16, PDF page 19**

QUOTE: "The analysis below references certain sources that were reviewed by the Board in YEC's recent Part 3 application regarding the Battery Energy Storage System (BESS project) and YEC's 2021 General Rate Application (2021 GRA). These sources include:

…

- Goals outlined in Yukon government's draft 'Our Clean Future: A Yukon strategy for climate change, energy and a green economy'
- Relevant Order-in-Council (OIC) directions to the YUB affecting costs to be included in YEC's rates as approved by the Board."

QUESTION:

a) Please explain the applicability of OIC 2021/16 to this project.

b) Provide a copy of the draft or final report "Our Clean Future: A Yukon strategy for climate change, energy and a green economy" that is referred to in the above quote.

c) Page 21 of the Application, PDF page 24, refers to the Clean Energy Act. How should the Board assess the relevance of this act in making its recommendations to the Minister when the act has not been enacted, i.e., consultations recently closed in January 2022?

ANSWER:

(a)

As stated on page 16 and in footnote 16 of the Submission – OIC 2021/16 is applicable insofar as it relates to the use of long term average (LTA) annual renewable source availability (which includes IPP renewable sources such as Atlin) for forecasting renewable generation available to contribute to meeting forecast customer requirements when setting YEC rates.

This IPP direction established the relevance and basis for assessing LTA thermal displacement expected to result from the Atlin EPA, and its effect on YEC costs to be used when the YUB sets YEC rates.

(b)

Please see Attachment 1 (final report) and Attachment 2 (draft report) to this response.

(c)

The Yukon government has indicated its intention in Our Clean Energy Future to bring into force the Clean Energy Act – and Yukon Energy understands that this would require YEC to meet a 93% Renewable Portfolio Standard. As noted in the question, public consultations on this Act closed in January 2022

While the specific legislation has not yet been enacted, the expected requirement for Yukon Energy to meet the standards outlined in the proposed Act (and potential consequences for Yukon Energy should it fail to meet standards outlined in the proposed Act) can inform the consideration of the public need for the Atlin Project EPA, and the basis for the EPA as a preferred alternative for meeting YIS capacity and energy requirements, when the Board advises the Minister.

ISSUE: **Hyperlinks**

REFERENCE: **Application, footnotes 22 and 24, page 18, PDF page 21**

PREAMBLE: **The Board has previously determined that hyperlinked documents are unacceptable as, over time, the links may be broken.**

QUESTION:

a) Please provide the hyperlinked documents referred to in footnotes 22 and 24 in PDF form.

ANSWER:

(a)

See Attachment 1 and Attachment 2 to this response.

YUKON UTILITIES BOARD

Report to Yukon Minister of Justice

Yukon Energy Corporation Application for Energy Project Certificate

and Energy Operation Certificate

Regarding the Proposed

Battery Energy Storage System (BESS) Project

June 30, 2021

1. INTRODUCTION

On December 17, 2020, the Government of Yukon designated the Yukon Energy Corporation's (YEC's) proposed Battery Energy Storage System Project (BESS Project) as a regulated project under Part 3 of the *Public Utilities Act*.[1] On January 21, 2021, YEC filed an application for an energy project certificate and an energy operation certificate for the BESS Project (Application) with the Minister of Justice (Minister).

In a February 2, 2021 letter, the Minister referred the Application to the Yukon Utilities Board (Board) for a review and hearing pursuant to Part 3 of the *Public Utilities Act*. The letter included Terms of Reference, which set out the purpose and the specific aspects of the BESS Project to be reviewed, and stipulated that the Board hold a public hearing and submit its report and recommendations to the Minister no later than May 17, 2021.

On March 10, 2021, the Board requested that the Minister extend the reporting deadline to the end of July 2021. The Minister responded to the Board letter on April 16, 2021 and, pursuant to section 41(1) of the *Public Utilities Act*, granted the Board's request and required the Board to provide a report with its recommendations by June 30, 2021.

On February 18, 2021, the Board issued Board Order 2021-03, which gave notice of the Application, set out the process schedule for the Application up to the submission of intervener evidence, and stated that further process would be determined after April 9, 2021. Board Order 2021-03 also requested that parties intending to participate in the proceeding register in writing with the Board by March 1, 2021.

The Board received requests for intervener status from ATCO Electric Yukon (AEY), the Utilities Consumers' Group (UCG), the Yukon Conservation Society (YCS), and from John Maissan. All requests for intervener status were granted.

The Board issued further Board Order 2021-06 on April 16, 2021, which established the remaining process schedule, including the opportunity for the public to provide written comments on the Application by April 30, 2021. Board Order 2021-06 also set the virtual oral hearing process. The Board issued correspondence on April 27, 2021 providing the protocol for the virtual hearing.

All interveners were provided the opportunity to submit information requests (IRs), file evidence, cross-examine the YEC witnesses, and provide final submissions. No comments were received from the public on YEC's Application by the April 30, 2021 deadline.

Board comments on the timing of the Application

YEC's Application was submitted to the Board by the Minister on February 2, 2021 with the expectation that the Board complete its report by May 17, 2021. YEC supported that deadline by stating that work on the BESS Project must commence by the summer of that year.

---

[1] Order-In-Council 2020/180 – Designating the Battery Energy Storage System Project as a Part 3 *Public Utilities Act* regulated project.

The Board is concerned with short deadlines for Part 3 applications. Board members serve on a part-time, volunteer basis, with contracted supporting resources. The Board requires sufficient time to discharge its mandate, considering these constraints. For example, the established metric for this Board to produce a report or major decision is generally 90 days from the close of record. In this case, a general rate application (GRA) was already in front of the Board when the Minister imposed its timeline for this Part 3 application proceeding, raising additional resourcing concerns. In addition, the Board is concerned that a short deadline for a Part 3 application may not allow sufficient time for the administrative and regulatory procedures necessary to effectively and fairly process a Part 3 application.

For future Part 3 applications, YEC is expected to build time into the regulatory schedule for the Minister to review and refer the application to the Board and to provide a reasonable time period for any public sessions, a sufficient time period for record development before the Board, and 90 days for the decision report. Sufficient time for the review, referral, and Board hearing process allows for procedural fairness to parties to the proceeding and protects the integrity of the regulatory process. A shortened timeline should only be allowed in exceptional circumstances.

2. OVERVIEW OF THE APPLICATION

In its Application, YEC stated that the BESS Project consists of a containerized lithium ion battery energy storage system on a 1.5 hectare site that YEC will lease on undeveloped Kwanlin Dün First Nation (KDFN) Category B settlement land located northeast of the intersection of Robert Service Way and the Alaska Highway in the City of Whitehorse.

The BESS will be connected to the YEC Whitehorse Rapids facility by a new 1.7 kilometre, 34.5 kilovolt (kV) transmission line that runs north of the KDFN site, following existing easements through forested Crown land until it meets and follows the path of an existing AEY 34.5 kV line to the Whitehorse Rapids facility.

The proposed BESS Project involves a grid-sized BESS with 40 MWh of useful energy storage capacity and 20 MW of inverter and transformer capacity that together will provide 7.2 MW of dependable capacity to the Yukon Integrated System (YIS) for 20 years, starting in the winter of 2022-23.

YEC expects that 7.2 MW of dependable capacity provided by the BESS Project will reduce the need to rely on rental of diesel generators during the winter months and will displace four 1.8 MW diesel rental units to address capacity shortfalls. YEC argued that the BESS Project will also provide other benefits, including: operating reserve that reduces thermal generation requirements; enhanced black start capability; and opportunities for diesel peak shifting.

The BESS Project lies within the overlapping traditional territory of the Ta’an Kwäch’än Council (TKC) and KDFN. YEC stated that it engaged with both First Nations in Q2 of 2020 to form a trilateral committee for sharing BESS Project information and assessing three potential KDFN and TKC sites for the BESS Project. The BESS Project includes a debenture investment opportunity for both TKC and KDFN.

The preliminary capital cost estimate (in 2020 dollars, with a +/- 30% accuracy) for the BESS Project is $31.7 million. After $16.5 million in funding from the Government of Canada's Investing in Canada Infrastructure Program ("ICIP"), the preliminary net capital cost estimate to be borne by ratepayers is estimated at $15.2 million.[2]

3. TERMS OF REFERENCE

The Minister stated that the general purpose of the review and hearing of the Board was to "obtain the YUB's report and recommendations on the potential benefits, costs, risks and customer impacts that influence whether the BESS Project should proceed as proposed by YEC, and any terms and conditions which the YUB considers should apply."[3] In the Terms of Reference, the Minister requested that the Board review the following specific aspects of the BESS Project:

> The YUB shall report on, and make recommendations about, the necessity for the BESS Project and its timing and design, with particular regard to:
>
> a. The public need for the BESS Project under various reasonable electric load forecasts, including near term requirements related to industrial and nonindustrial loads, and the effect of the project on the rates of customers and the reliability of electricity service provided to customers.
>
> b. The capability of existing and currently committed and expected generation and transmission facilities, including thermal generation facilities to provide reliable electric power generation to meet the forecast load requirements and YEC's capacity planning criteria and the effect of the BESS Project on this capability.
>
> c. The risks for the BESS Project and their potential impacts on rates for customers and on the reliability of electricity service provided to customers.
>
> d. What, if any, reasonable alternatives exist to the BESS Project or what alternative ways of undertaking the BESS Project with its selected technology might be advisable given reasonable load assumptions and risk assessments.
>
> e. Impacts on YEC and ratepayers of the debenture investment opportunity that YEC is providing to TKC and KDFN in recognition of the BESS Project's location on the overlapping Traditional Territory of TKC and KDFN and the benefits of TKC and KDFN support for this Project's development at this time.
>
> f. Whether it is prudent to build the BESS Project as proposed at this time.[4]

The Minister stated that the Board shall provide a recommendation on whether YEC should be granted an energy project certificate and an energy operation certificate for the BESS Project and whether the certificates should be subject to any terms and conditions. The Minister also added

[2] YEC Application, PDF page 7.
[3] Minister of Justice's BESS Terms of Reference, February 2, 2021, PDF page 2.
[4] Minister of Justice's Terms of Reference, February 2, 2021, PDF pages 2 and 3.

that the Board may make any other recommendations or provide any other information that it considers advisable in the circumstances.

3.1 Public Policy and Ratepayer Costs

During the proceeding, YEC stated that its board of directors made the decision to not pursue a permanent thermal plant and instead to focus on renewable projects. YEC also stated that its board of directors has a deliberate strategy that the major capital projects, such as the BESS Project, are to involve economic opportunities for First Nations. Siting the BESS Project on settlement land was referenced as a mechanism to achieve that goal. As proposed, the BESS Project triggers public policy considerations that are in the jurisdiction of government.

The Board's recommendations for the BESS Project are based on the Board's jurisdiction under Part 3 of the *Public Utilities Act*, which gives the Board the authority to make recommendations about the approval of the energy project certificate and the energy operation certificate for a facilities project in Yukon. After receiving the Terms of Reference from the Minister, the Board holds a hearing and prepares its report, which includes any recommendations of the Board. The Board can recommend that the Minister approve the project, deny the project, or approve the project with conditions.

The Board is an administrative tribunal established by the Government of Yukon, responsible to ensure that the utility services in Yukon take place consistent with the public interest. The Board is an economic regulator that determines just and reasonable rates for Yukon utilities within its jurisdiction.

As part of discharging its mandate under the *Public Utilities Act* and considering the Minister's Terms of Reference for the BESS Project, the Board must look at the need for the project, the impact of the BESS Project, the cost implications to ratepayers, and system reliability.

The Board is not allowed to consider public policy that is beyond its mandate, such as climate action or the government's direction to advance economic development for First Nations. There may be externalized economic costs and benefits of these public policy considerations, but these items are not within the Board's determinations to be made under the Terms of Reference.

The BESS Project is proposed as part of a larger renewable electricity strategy to address climate change by reducing fossil fuel use, and may result in higher costs to the ratepayer than more traditional energy options. Similarly, the choice to require siting of the proposed project on First Nation land, including a sole-sourced investment opportunity, may also result in ratepayer impacts.

A portion of the total cost of the BESS Project will be covered by funding from the federal government. YEC confirmed in testimony that the focus of its board of directors, flowing from the policy direction of the territorial and federal governments, is on renewable energy. It is worthwhile for the Minister to consider how much of a project should be financed through government and paid for by the taxpayer and how much should be financed by ratepayers through utility rates if a proposed project seeks to achieve public policy goals.

The role of YEC, as a regulated utility, is to provide safe, reliable, and cost-effective energy services. In this case, YEC argues that, as proposed, there is an economic benefit to ratepayers of the BESS Project compared to the alternative it put forward, which is the current practice of renting diesel generators to meet capacity shortfalls.

However, as the project economics are based on preliminary estimates with many outstanding agreements, including battery procurement, land leasing, and the investment opportunities for the TKC and KDFN through debenture agreements, there will be variability in the actual costs from what is presented in the current Application and reviewed by the Board. The BESS Project, as a proposed renewable facilities project under Part 3 of the *Public Utilities Act*, attracts risk. Ultimately, ratepayers could bear the cost in excess of a least cost or more proven, conventional alternative.

The Board recommends that, if there is Ministerial approval of this project, there should be comment on the public policy issues considered with regard to climate change and First Nation economic development opportunities, as there are real cost drivers stemming from these public policy issues. This is particularly important because actual costs of the project after it is approved by government could be disallowed by the Board during its prudency review in a future GRA. Disallowed costs are ultimately paid by taxpayers and not YEC's customers, the ratepayers.

In response to Board questions during the hearing, YEC stated that, if there is a premium to going green, its approach is to pursue federal funding to reduce the costs of the BESS Project to ratepayers. As stated above, the consideration of the benefits expected from First Nation economic development, or from reductions in greenhouse gas emissions, are not factors which the Board can consider within its mandate.

4. NECESSITY FOR THE BESS PROJECT

4.1 Public Need for the BESS Project — Term of Reference 3.a.

In the Terms of Reference, the Minister requested the Board to report on and make recommendations about the necessity for the BESS Project and its timing and design, with particular regard to:

> 3.a. The public need for the BESS Project under various reasonable electric load forecasts, including near term requirements related to industrial and nonindustrial loads, and the effect of the Project on the rates of customers and the reliability of electricity service provided to customers.[5]

Yukon Energy Corporation

YEC provided a 2021-2030 forecast non-industrial peak load and a forecast dependable capacity, excluding mobile rented diesel units. YEC projected that load and capacity shortfall would continue to increase during that time period. YEC attributed the increase in load to the new

[5] BESS Terms of Reference, PDF pg. 2

industrial mine loads at the Minto, Alexco, and Victoria Gold mines[6] and to electrification policy initiatives, such as the Government of Canada's zero-emission vehicles sales target of 10% by 2025, 30% by 2030, and 100% by 2040.[7]

YEC's current method of mitigating the capacity shortfall is relying on rented diesel units. However, in YEC's view, these units introduce risks since there are uncertainties around their continued availability, their acceptable performance, and YEC's ability to spatially accommodate the units. YEC stated that these risks potentially expose grid customers to unreliable generation capacity.[8] For these reasons, YEC submitted that maintaining the status quo was not a feasible option in the circumstances and that permanent solutions were needed.

YEC indicated that, as provided for in its 2016 Resource Plan and 10-Year Renewable Electricity Plan, it continues to pursue new renewable energy development to reduce its reliance on thermal generation. Part of this renewable strategy is to develop the BESS Project.[9] YEC stated that the primary need for the BESS Project is to help meet its dependable capacity requirements under the N-1 criterion for the YIS. YEC defined "dependable capacity" as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months based on the inflows of the five driest inflow years in history.[10]

YEC anticipated that the BESS Project would provide 7.2 MW of dependable capacity in the near term, displacing the requirement to rent four diesel units rated at 1.8 MW. YEC considered other alternatives and indicated that these alternatives did not provide dependable capacity in the near term. For example, one of the options included the Whitehorse Hydro #4 (WH4) Uprate Project, which would increase the maximum water flow and provide 0.9 GWh of annual additional energy. However, due to the downstream Yukon River system ice flow restrictions, the WH4 Uprate Project would not provide additional dependable capacity.

YEC advised that the BESS Project would be required to close the gap in the capacity shortfall, even if the other major projects in the 10-Year Renewable Electricity Plan proceeded; namely, the Atlin Hydro Expansion and the Moon Lake Pumped Storage projects. YEC submitted that, after connecting the Atlin Hydro Expansion project, there would still be around 8.9 MW of capacity shortfall.[11] YEC indicated that if the Moon Lake Pumped Storage project connected and there was no BESS Project, there would be a slight capacity surplus in 2028-29, but then a capacity shortfall would exist in the following years.[12]

---

[6] YEC Application, Section 4.1.2, PDF page 29.
[7] YEC responses to YUB IRs, YUB-YEC-1-1, PDF page 7.
[8] YEC Application, Section 4.2, PDF page 33.
[9] YEC Application, Section 4.1.2, PDF page 29.
[10] YEC responses to YUB IRs, YUB-YEC-1-17, PDF page 46.
[11] YEC Application, Section 4.1.2, PDF page 32, Table 4-1.
[12] Transcript Volume 2, PDF page 8, lines 17 to 25, and PDF page 9, lines 1 to 9.

YEC indicated that the BESS Project would reduce ratepayer costs compared to rented diesels or any other option, citing the following unique features as contributing to ratepayer savings:

- A $16.5 million federal grant, which reduces the estimated capital cost (2020$) to $15.2 million;

- Displacement of diesel rental costs (or similar fixed capital and non-fuel O&M [operations and maintenance] costs for any other thermal option considered);

- Operating reserve use savings from the battery, displacing thermal generation driven by the current requirements to use hydro for operating reserve [footnote removed]; and

- Fuel cost savings from battery use for diesel peak shifting.[13]

YEC stated that net ratepayer savings would occur each year with the BESS Project and that there would be $12.7 million net present value ratepayer savings over the 20-year project life. The estimate of annual ratepayer impacts was provided in Table 4-3 in YEC's Application[14] and excluded additional thermal fuel cost-saving benefits from improved hydro unit efficiency, nonfuel thermal O&M cost savings, or updated thermal fuel prices.[15] In response to one of John Maissan's IRs, YEC provided updated versions of Table 4-3 based on the following conditions: March 2021 LNG and diesel fuel prices, the project coming in at 30% below the estimate, the project coming in at 30% above the estimate, and long-term avoided costs of diesel and LNG at $0.277 per kWh and $0.248 per kWh, respectively.[16] YEC stated that ratepayer benefits were demonstrated in each of the updated tables.[17]

Regarding the reliability benefits of implementing the BESS Project, YEC noted that the project would reduce the impact of outages on customers, improve overall reliability of service, and enhance the capability of the system to integrate new Independent Power Producer (IPP) renewable generation.[18] The BESS Project would primarily be used to contribute to the N-1 capacity reserve required to meet YEC's non-industrial peak load under the single largest contingency, which would be the loss of the Aishihik generating facility or the transmission line connecting the facility to the YIS.[19] The BESS Project would also provide operating reserve

[13] YEC Final Submission, PDF pages 6 and 7.
[14] YEC Application, Section 4.3.2, PDF page 43, Table 4-3.
[15] YEC Final Argument, PDF page 8.
[16] YEC responses to John Maissan's IRs, JM-YEC-1-33, PDF pages 43 to 46.
[17] YEC Final Argument, PDF page 8.
[18] YEC Final Argument, PDF page 8.
[19] YEC responses to YUB IRs, YUB-YEC-1-36, PDF page 138.

when excess water is available, allowing hydro generating units to operate more efficiently and meet system load and reduce the reliance on thermal generation.[20]

YEC stated that using the BESS Project could save up to 1,837 MWh of diesel and 17,043 MWh of LNG, or $3.374 million, based on 2021 fuel prices.[21] According to YEC, this estimate was conservative because it assumed one-third of the Hatch Engineering Utility Battery Feasibility Study Final Report (Hatch report)[22] estimated thermal fuel generation, did not include any nonfuel O&M cost savings or benefits for improved hydro unit efficiency, and used lower fuel prices from mid-2020.[23]

YEC identified that the BESS Project provided other reliability benefits, including diesel peak shifting, rapid black start and outage restoration, grid reliability and ancillary services (including frequency regulation, coverage of large generation unit outages, prevention of load shedding events and renewable integration), load loss stabilization, and reactive power support.[24] While YEC estimated a small net economic benefit of approximately $10,600 per year (estimated in 2022$) for diesel peak shifting, it could not quantify the economic benefits for the other reliability benefits.[25]

Yukon Conservation Society

YCS was in favour of the BESS Project, indicating that one of the primary benefits was the project's ability to integrate renewable generation onto the YIS. YCS agreed with the technical and ratepayer benefits provided by YEC in the Application. YCS indicated that the forecast in ratepayer savings in response JM-YEC-1-33(a)[26] was conservative, as it did not include volatility of future diesel fuel prices and application of a future carbon tax. If a federal carbon tax was implemented, YCS submitted that ratepayers would realize even further savings with the BESS Project.[27] YCS also noted that the project would allow the YIS to become more resilient to climate change and add "robustness" to the system in cold winters when there is a higher risk of ice build-up downstream of a hydro generating facility.[28]

John Maissan

John Maissan agreed that there was a public need for the BESS Project, indicating that the reliability of service would increase and that all customers would experience rate benefits.

---

[20] YEC Application, Section 3.1.2.2, PDF pages 14 and 15.
[21] YEC Application, Section 4.2.3, PDF page 42.
[22] YEC Application, Appendix B: Hatch Engineering Utility Battery Feasibility Study Final Report – Phase 1, PDF pages 55 to 178.
[23] YEC Final Argument, PDF page 12.
[24] YEC Opening Statement, PDF page 5.
[25] YEC Application, Section 4.2.3, PDF page 42.
[26] YEC responses to John Maissan's IRs, JM-YEC-1-33(a), Table 1, PDF page 43.
[27] YCS Final Argument, PDF page 6.
[28] YCS Final Argument, PDF page 5.

Mr. Maissan stated that peak non-industrial load has been growing in recent years, mentioning the three grid-connected mines and increase in new residential housing. In Mr. Maissan's view, while YEC is increasing its renewable energy supply options, the YIS will not be able to meet the N-1 planning criterion without rented diesel generating units, until the Moon Lake Pumped Storage project connects a decade from now.[29]

Mr. Maissan stated that, to provide a unit of dependable capacity, a generating unit did not need to be running at capacity continuously and was only required to lower the peak load.[30] The peak load occurs over a short period of time, and smaller amounts of dependable capacity are required for the remainder of the day. The BESS Project could reduce the load by 7.2 MW during the peak load hours and then be recharged during the nighttime. Mr. Maissan added that YEC had been conservative in estimating the net present value of the project.[31]

Mr. Maissan agreed with YEC's assertions that the BESS Project could assist in operating reserve support, diesel and LNG peak shifting, grid reliability, load loss stabilization, black start and outage restoration, and ancillary services and reactive power support.

Utilities Consumers' Group

UCG had concerns with the certainty around system load levels presented by YEC in the Application. It stated that YEC acknowledged uncertainty around the changing plans of industrial customers. As a result, UCG concluded that YEC continued to make an error of applying sales growth rates experienced over past time periods to derive weather-normalized use per customer forecast.[32] UCG questioned why YEC was not pursuing installation of on-site generation with guaranteed upfront payment for interim mining loads, as on-site generation with guaranteed upfront payment by these industrial loads would protect the interests of other Yukon ratepayers.[33]

Finally, UCG submitted that YEC's board of directors' instruction to focus on renewable projects prevented YEC from completing a fulsome review of potential alternatives in closing the capacity shortfall gap, e.g., pursuing a large new permanent diesel plant instead of the BESS Project.

Board Views

The Board provides its report and recommendations about Section 3.a. of the Terms of Reference in the following three subsections:

(i) the public need for the BESS Project under various reasonable electric load forecasts, including near-term requirements related to industrial and non-industrial loads;

[29] John Maissan Final Argument, PDF page 2.
[30] John Maissan Final Argument, PDF page 3.
[31] John Maissan Final Argument, PDF page 8.
[32] UCG Final Argument, PDF page 8.
[33] UCG Final Argument, PDF page 8.

(ii) the effect of the BESS Project on the rates of customers; and

(iii) the reliability of electricity service provided to customers.

Public Need for the Bess Project

The Board finds that a need for the BESS Project in the near term has been established. The Board agrees with YEC's and Mr. Maissan's submissions that new load growth is anticipated due to: new industrial mine loads at the Minto, Alexco and Victoria Gold mines; an increase in residential housing in Yukon and an associated increase in demand for electric heat; and government electrification policy initiatives resulting in, for example, a projected increase in zero-emission vehicles.

In the circumstances detailed by YEC in its Application, supporting documents, and testimony, the Board finds sufficient evidence on the record to reasonably accept that load will continue to grow and that a large capacity shortfall gap will exist until YEC connects additional supply options. One of these options is the BESS Project, and removing it from the supply mix would keep the system at a capacity shortfall.

Currently and into the future, unless a permanent thermal option is pursued, YEC will need to continue relying on rented diesel units to address the capacity shortfall. The BESS Project is expected to operate in lieu of, and eliminate the need to rent, four 1.8 MW diesel units. In its Application, YEC mentioned the challenges of finding these rental units and locating and connecting these units safely to the YIS.[34] YEC provided the Board with its competitive process for sourcing rented diesel units in 2018-19, 2019-20, and 2020-21. During the years 2018-19, 2019-20, and 2020-21, YEC ran a one-year public competitive tender process for six 2-MW units for placement at the Whitehorse Rapids Generation Station, a three-year tender process for up to eight 2-MW units, and is searching the market for cost-effective options for rental units, respectively.[35] YEC also confirmed at the hearing that rented diesel units are not as reliable as more permanent solutions.[36] The Board is persuaded that only relying on rented diesel generators would be challenging and would not be a reliable way of closing the capacity shortfall gap.

YEC indicated that one alternative to meeting the capacity shortfall would be to connect a permanent thermal (diesel) plant. However, YEC stated that this option held less popularity with stakeholders in public consultation and was rejected by its board of directors.[37] While the BESS Project drew some stakeholder concerns, YEC indicated that the concerns were fairly manageable.[38] From that perspective, the Board considers that the BESS Project appears more favorable to stakeholders than a permanent diesel plant at this time.

[34] YEC Application, Section 4.2, footnote 40, PDF page 33.
[35] YEC responses to YUB IRs, YUB-YEC-1-17, PDF pages 46 and 47.
[36] Transcript Volume 1, PDF page 123, lines 21 to 23.
[37] YEC responses to YUB IRs, YUB-YEC-1-43, PDF page 159.
[38] Transcript Volume 1, PDF page 170, lines 10 to 14.

The effect of the project on the rates of customers

While the Board finds that there is a public need for the BESS Project, the ratepayer savings proposed by YEC are less persuasive to the Board. This is because the BESS Project is finishing the planning phase and moving to the procurement process stage, meaning that project costs are not firm.

While the Board agrees that the information provided on the record suggests ratepayer benefits, a significant part of the capital costs is associated with the battery, for which YEC is currently in the first stage of the procurement process.[39] In response to an information request from Mr. Maissan, YEC submitted that, over its predicted life, the BESS Project would break even in terms of no longer providing ratepayer savings if the capital costs increased by 42.5%.[40]

At the hearing, YEC mentioned that, over the next few months, it would receive details from the request-for-proposal (RFP) process for the battery, which would then confirm a substantial portion of the capital cost. YEC would then go to its board of directors to make a final investment decision.[41] As stated, the Board had no information on the selected vendors and the costs associated with these vendors because YEC has not finished the RFP and selection processes.

In addition, the Board is unsure whether the projected cost savings will remain for the 20-year project lifespan or if the BESS Project will last for 20 years. The long-term costs will likely be impacted by the vendor selected, obligations of the vendor, and any agreements with the First Nations for land lease and investment, as well as costs for mitigations required from YESAB, Nav Canada, and Transport Canada permits and any other currently unknown costs associated with outstanding permits, purchases, negotiations, and other agreements. It is for these reasons that the Board cannot fully accept the estimated economic benefits of the BESS Project provided by YEC for operating reserve support and diesel peak shifting, both in the short and long term.

Given the early stage of the project and the significant +/- range to the engineering estimates, the Board finds that there are too many uncertainties for it to make a recommendation on the effect of the BESS Project on the final rates of customers. As noted throughout this report, the final costs to be included in rates will be subject to a prudency review in YEC's future GRA.

Reliability of electricity service

With regard to reliability, the Board agrees that the BESS Project could provide operating reserve support and increase grid reliability. While YEC brings up additional reliability benefits for the BESS Project, the Board notes that these benefits are not significantly required to meet a

[39] YEC responses to YUB IRs, YUB-YEC-1-13, PDF page 37.
[40] YEC responses to John Maissan's IRs, JM-YEC-1-33, PDF page 43.
[41] Transcript Volume 2, PDF page 20, lines 13 to 19.

need at this time. The Board elaborates on its views around reliability in Section 3(b) of this report.

4.2 Capability of Existing and Expected Assets to Meet Forecast Load Requirements — Term of Reference 3.b.

The Minister's Terms of Reference requested the Board to report on and make recommendations about the necessity for the BESS Project and its timing and design, with particular regard to:

> 3.b. The capability of existing and currently committed and expected generation and transmission facilities, including thermal generation facilities to provide reliable electric power generation to meet the forecast load requirements and criteria and the effect of the BESS Project on this capability.

Yukon Energy Corporation

YEC stated that 84% of its 2021 forecast generation would be supplied by hydroelectric generation, with almost all of the balance supplied by diesel and LNG thermal generation.[42] Since Yukon's system is an isolated grid, YEC must supply its own capacity and energy, which includes securing reserve capacity in order to meet load during the winter peak periods. As mentioned in Section 3(a) of this report, YEC's generation capacity planning criterion is based on the single contingency dependable capacity criterion, which requires the YIS to have enough dependable capacity to supply the forecast non-industrial peak winter demand under the largest single contingency.

YEC stated that planning is based on non-industrial load since all major industrial customers maintain sufficient on-site generation for their own emergency purposes. YEC submitted that all of the renewable and thermal supply options identified in the Application are required to remove reliance on rented diesel units in order to address the existing and ongoing forecast capacity shortfall.[43] Added to this, YEC represented that the BESS Project would provide support in meeting the dependable capacity criterion. More specifically, the BESS Project would provide 7.2 MW of dependable capacity in the near term, displacing the requirement to rent four diesel units rated at 1.8 MW.

YEC explored a variety of energy storage technologies, including storage through pumped hydro, compressed air, flywheel, flow battery, lead acid battery and supercapacitors, and found that the lithium ion battery technology was best suited for meeting its generation capacity planning criterion. YEC planned to develop the project using construction technologies that it states are suited for northern climate conditions and using similar technology employed for battery projects installed in Northern Quebec, the Northwest Territories, and Alaska.[44]

---

[42] YEC Application, Section 4.1.2, PDF page 28.
[43] YEC Final Argument, PDF page 10.
[44] YEC Opening Statement, PDF page 6.

YEC indicated that the BESS would be designed to meet the following standards:

- UL 1642 Standard for Lithium Batteries
- UL 1973 Standard for Batteries for Use in Light Electric 1 Rail (LER) Applications and Stationary Applications
- UL 9540 Standard for Energy Storage Systems and Equipment
- NFPA 855 Standard for the Installation of Stationary Energy Storage Systems
- IEEE 1547 Standard for Interconnecting Distributed Resourced with Electric Power Systems
- UL 1741 Inverters Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources[45]

YEC added that it would take a number of proactive steps to ensure that fire and other safety risks were managed effectively. YEC indicated that fire suppression would be a key component of the battery system design and selection and that the design would use several automated mechanisms to prevent fires from starting. More specifically, YEC would install a fire suppression system and alarms in each battery container, check and maintain the fire suppression system routinely, use fire-retardant module containers to isolate a single pack of battery cells if a fire occurs, use containers with pressure relief valves that allow gas to escape and prevent a container explosion, space the containers apart to prevent a fire from spreading, develop a comprehensive fire and emergency response plan, and commit to providing the required training to local firefighters and emergency response staff.[46]

YEC advised that an essential requirement for reliable operation of the Yukon system is ensuring that there is enough operating reserve support to accommodate for variations in load. Currently, the operating reserve criteria are achieved by operating a hydro generating unit below its maximum capacity. Thermal generation is used to meet load that exceeds the available hydro generation. YEC indicated that if the BESS Project is used for operating reserve support, there would be a direct reduction in thermal generation and improved efficiency of hydro generating units by operating them at their most efficient output more frequently.[47] For example, if a modest efficiency gain of 0.5 to 1% was realized for the hydro generating units, 2.2 to 4.4 GWh of additional energy would be provided by the hydro generating units.[48]

YEC submitted that utilizing the BESS Project as an operating reserve was compatible with using the project in meeting the N-1 dependable capacity criterion. The first reason given was that both required the BESS to retain storage in different time periods. More specifically, the N-1

[45] YEC responses to YUB IRs, YUB-YEC-1-56, PDF pages 315 and 316.
[46] YEC responses to YUB IRs, YUB-YEC-1-46, PDF pages 168 and 169.
[47] YEC Final Argument, PDF page 12.
[48] YEC Application, Section 3.1.2.2, PDF page 16.

dependable capacity would be for events during the coldest period of winter, a time when using the BESS for operating reserve support provides minimal benefit in reducing net thermal generation.[49] The second reason given was that both use cases (meaning the N-1 use case and the operating reserve use case) would have minimal impact on battery life, with an estimate of one 30-minute operating reserve event per month and one two-week N-1 event every 10 years.[50]

In addition to providing support in meeting the N-1 dependable capacity criterion and operating reserve requirements, YEC indicated that the BESS Project would provide other reliability benefits, which included diesel peak shifting, rapid black start and outage restoration, grid reliability and ancillary services, load loss stabilization, and reactive power support.

YEC advised that the BESS Project could be discharged in lieu of diesel generation during peak hours and recharged overnight with LNG or hydro generation, thereby reducing thermal fuel costs and greenhouse gas emissions.[51] YEC indicated that the BESS had the potential to shift between 108 to 244 MWh per year of diesel generation between Whitehorse and Faro diesel. However, YEC noted that if the BESS Project was providing operating reserve during periods of peak diesel generation, a priority must be set for BESS operation,[52] since operating reserve support could not be provided at the same time as diesel peak shifting.

YEC described its current process for black start and outage restoration in its Application and submitted that the BESS Project could improve this process. When YEC is required to perform black start operation, it sectionalizes the YIS into smaller load segments that are re-energized sequentially using smaller individual generators. Because the system is segmented into numerous load blocks, and because some of the switching is of a manual nature, the process can take up to two hours depending on the extent and severity of the outage.[53] YEC submitted that the black start and outage restoration process would improve if the BESS was used for grid re-energization. The BESS Project would enable significantly larger load segments (more specifically, 20 MW) to be restored at once, meaning the project would enable rapid pickup of the grid.[54] However, YEC noted that this process accounted for more than half of the estimated BESS annual throughput, meaning the BESS Project would incur operating efficiency losses of 15% on the throughput.[55] YEC indicated that the overall savings from enhanced system restoration would offset any efficiency loss costs.

Regarding grid reliability and ancillary services, YEC stated the BESS Project could respond to large frequency excursions, cover the loss of large generating units, prevent load shedding events, and improve power quality and customer reliability.[56] More specifically, YEC advised

---

[49] YEC Final Argument, PDF page 12, footnote 17.
[50] YEC Final Argument, PDF page 12, footnote 18.
[51] YEC Application, Section 3.1.2.2, PDF page 18.
[52] YEC Application, Section 3.1.2.2, PDF page 18.
[53] YEC Application, Section 3.1.2.2, PDF page 17.
[54] YEC Application, Section 3.1.2.2, PDF page 17.
[55] YEC Application, Section 3.1.2.2, PDF pages 17 and 18.
[56] YEC Application, Section 3.1.2.2, PDF pages 18 and 19.

that the BESS could discharge prior to load shedding events or charge in the event of a significant load loss, both at a partial discharge or charge cycle.[57] YEC also highlighted that the BESS inverters could provide real and reactive power simultaneously to the YIS, since providing reactive power support did not deplete the energy stored in the BESS. However, significant reactive power compensation was not typically required on the YIS.[58]

Yukon Conservation Society

The views of YCS regarding this aspect of the project are similar to the views summarized in Section 3(a) of this report.

John Maissan

Mr. Maissan agreed that the BESS Project improved the capability of the Yukon system by providing reliable electricity service. More specifically, the BESS Project would support meeting the N-1 dependable capacity criterion, provide operating reserve support which would improve hydro generating unit efficiency and decrease reliance on thermal generation, improve grid reliability, improve the black start and outage restoration process, and provide ancillary service and reactive power support.[59] In Mr. Maissan's view, utilizing the BESS Project for operating reserve would allow for more efficient utilization of hydro generation and could reduce the amount of thermal generation required whenever load surpassed the reduced output of the hydro generating units.[60] Due to its instantaneous nature, the BESS Project could improve grid reliability by starting and supplying load a tripped generating unit was carrying within 150 to 200 milliseconds.[61] Mr. Maissan also supported the fact that the BESS Project could act as load and charge in circumstances where there is more generation on the YIS.

Utilities Consumers' Group

UCG was less inclined to support the BESS Project's effect on the system's capability of providing reliable electrical service. In its final submission, UCG stated that it was not clear whether the forecasts used to justify the need for the BESS Project were significantly influenced by climate change impacts. It submitted that the forecasting models were proven to be very costly for Yukon ratepayers and that there continued to be a lack of evidence that showed the models provided accurate forecasts.[62] UCG mentioned the YECSIM model[63] and stated that

---

[57] YEC responses to YUB IRs, YUB-YEC-1-61, PDF page 362.
[58] YEC Application, Section 3.1.2.2, PDF page 14.
[59] John Maissan Final Argument, PDF page 6.
[60] John Maissan Final Argument, PDF page 4.
[61] John Maissan Final Argument, PDF page 4.
[62] UCG Final Argument, PDF page 10.
[63] UCG explained that the YECSIM model is a power benefits simulation model developed in 2007 by KGS Ground Consulting Engineers and that it is used by YEC to forecast its long-term average hydro generation for different load scenarios. UCG indicated that the YECSIM model is custom-made to consider all significant factors affecting the operation of YEC's system, including complex rules of operation and regulatory demands on YEC. See UCG's Final Argument, PDF page 10.

there was a lack of comparing actual with forecasts made with using the model to verify accuracy.[64]

Board Views

The BESS project supports YEC in its capability of providing reliable electric power supply to meet the forecast load requirements in future years. From the information that has been presented on this record, the Board is satisfied that the project will not hinder existing and currently committed (and expected) generation and transmission facilities.

For example, the Board asked YEC questions regarding the transmission requirements for the BESS Project.[65] YEC responded that the BESS Project would be connected under the Whitehorse Interconnection Project, which was currently in preliminary stages. YEC advised that the Whitehorse Interconnection Project would be required regardless of whether the BESS Project proceeded. Accordingly, the BESS Project fits within YEC's already existing plans for upgrading the YIS.

At this stage of project development, YEC is considering requests-for-proposals from vendors for the following lithium ion battery chemistries: nickel manganese cobalt lithium (NMC), nickel cobalt aluminum lithium (NCA), and lithium iron phosphate (LFP). While there are some variations in battery chemistries,[66] based on the information before it, the Board finds sufficient evidence to suggest that any of the battery chemistries are likely suitable for the BESS Project. However, the Board expects YEC to follow all applicable design standards and take all of the steps necessary to ensure that fire and other safety risks are managed effectively, as was outlined in the Application.

The BESS Project provides N-1 capacity support in the winter season. By definition, this is idle capacity waiting for a catastrophic event (the N-1 event) to activate and operate. Currently, the rented diesel units meet this requirement, and the BESS would likely displace the future need for four additional rented diesel units. An economic and system benefit of the BESS is that it also supports the operating reserve requirements of YEC and, in doing so, could allow for gains in efficiency for hydro generating units. Currently, a hydro generating unit must operate at less than its full capability in order to provide operating reserve to ramp up to address a loss in generation.[67] This means that there is more likelihood of load exceeding the available hydro generation, which will then require thermal generation to provide additional energy to meet the system load.[68] Using the BESS Project as an operating reserve allows hydro generating units to run at a higher output and reduces reliance on thermal generation. While YEC could not quantify the efficiencies gained by the hydro generating units connected to the YIS,[69] the Board agrees at

---

64 UCG Final Argument, PDF page 10.
65 YEC responses to YUB IRs, YUB-YEC-1-3, PDF pages 11 to 14.
66 Transcript Volume 1, PDF page 161, lines 19 to 25, and PDF page 162, lines 1 and 14 to 17.
67 YEC responses to YUB IRs, YUB-YEC-1-20, PDF page 55.
68 YEC responses to YUB IRs, YUB-YEC-1-20, PDF page 55.
69 YEC responses to YUB IRs, YUB-YEC-1-20, PDF page 54.

a conceptual level that the units will be used more efficiently since they will not be saving generation for operating reserve.

The Board also observes that YEC may choose on a given day in the winter not to use the BESS Project for other services, such as diesel peak shifting or responding to frequency events.[70] The Board interprets this to imply that the secondary reliability benefits of the BESS Project cannot be realized at all times. While the Board does not currently consider this to be a major concern, the number of times the BESS is used for secondary reliability benefits might increase as more renewable supply options connect to the YIS. For example, YEC stated that frequency excursion events are likely to increase as more intermittent renewables are added to the grid,[71] which would increase the use of the BESS for the secondary benefits. The Board foresees that there could be conflict between the secondary benefits of the BESS Project as more intermittent renewables are added to the grid and the addition of the BESS to assist YEC with meeting the N-1 dependable capacity criterion and providing operating reserve support in the future.

YEC’s proposal to meet these reliability requirements with the BESS is more favorable compared to the alternative of using rented diesel units, as it would automatically maintain system frequency and assist with automatic voltage control on the grid. In contrast, the purpose of rented diesel units was primarily for peaking generation and N-1, and was not intended to deal with YEC’s system as a whole.[72] Additionally, the BESS Project would increase the size of load segments that could be picked up during the black start process, thereby reducing the time required for grid restoration. More specifically, YEC stated that 20 MW of load could be brought up immediately.[73] YEC also noted that the BESS Project could be started instantaneously, whereas rented diesel units take approximately five minutes to start.[74] However, utilizing the BESS Project for black start and outage restoration would account for more than half of the estimated BESS throughput, resulting in operating efficiency losses.

The Board is unable to provide a recommendation as to whether overall savings from enhanced system restoration will offset any efficiency loss costs at this time because the BESS Project is in its preliminary stages. It is likely that the BESS Project will have to be operational before data will be available to inform the savings and the costs.

[70] YEC responses to YUB IRs, YUB-YEC-1-67, PDF page 371.
[71] YEC Application, Section 3.1.2.2, PDF page 19.
[72] Transcript Volume 1, PDF page 176, lines 18 to 20, and PDF page 178, lines 22 to 24.
[73] Transcript Volume 1, PDF page 180, lines 4 to 7.
[74] Transcript Volume 1, PDF page 180, lines 18 to 20.

4.3 Risks for the BESS Project and Impacts on Rates for Customers — Term of Reference 3.c.

The Minister's Terms of Reference request that the Board make recommendations about the necessity for the BESS Project, among other matters, with particular regard to:

> 3.c. The risks for the BESS Project and their potential impacts on rates for customers and on the reliability of electricity service provided to customers.[75]

YEC identified project risks in Section 4.3 of the Application. Project risks are categorized into two groups, as follows:

1. Group 1 – Project technical risks, design risks, and capital cost risks.
2. Group 2 – Risks related to timing delays from the Board, *Yukon Environmental and Socio-economic Assessment Act* (YESAA), NavCanada, and Transport Canada regulatory or permitting processes.

In YEC's view, the Group 1 risks were manageable through selection of an experienced vendor, use of an owner's (YEC or its designate) engineer with experience procuring battery vendors, and the ability to select the specific project solution based on both technical compliance and price and taking into consideration Whitehorse climate conditions.

Ratepayer impacts for Group 1 were tied to ultimate capital costs for the project, project performance and timing that affect the expected BESS benefits of reduced thermal generation, and improved reliability.

Group 2 risks related to the timelines that would delay the project from proceeding in mid-2021, resulting in an extended need and related costs for diesel rentals past the winter of 2022/23.

For Group 2, YEC stated that impact to ratepayers would relate to delays in the project proceeding and the added costs related to such delays.[76]

Yukon Conservation Society

YCS stated that the project has benefits from a technical standpoint and the benefit to ratepayers is a positive when compared to renting diesel generators. YCS added that the forecast benefit to ratepayers is conservative because it does not include volatility in diesel fuel prices in the future nor the potential of a carbon tax being applied to northern jurisdiction electricity providers.[77]

John Maissan

From a technical perspective, Mr. Maissan noted that BESS systems were being utilized globally using technologies similar to that proposed by YEC. He provided several examples of BESS projects in Canada. He added that the heating, ventilating, and air conditioning (HVAC) or

[75] Minister of Justice's Terms of Reference, PDF page 3.
[76] YEC Application, PDF pages 43 and 44.
[77] YCS Final Argument, PDF page 6.

temperature management systems required to meet local ambient conditions exist in Whitehorse and should not pose any problems for the BESS Project. Mr. Maissan's view was that the technical risk was low.[78]

For reliability, Mr. Maissan stated that all the planned functions of the BESS have positive results on either the YIS costs or on power reliability and quality.[79] Mr. Maissan noted that the Application demonstrated a financial benefit, with a net present value of $12.676 million. It was his view that this estimate was conservative and that the following benefits should also be considered:

- Avoided diesel rental costs
- Annual savings from operating reserve
- Annual savings from peak shifting
- Financial savings due to updated fuel prices
- Variable operating cost savings are not presently included in thermal generation savings
- Modest efficiency gains of 0.5 to 1% in the hydro generator operation with the BESS providing the operating reserve
- Reduced diesel generation due to a reduction in grid outages and faster restoration from outages
- Consumer benefits and cost savings due to fewer unscheduled outages
- Savings from avoided potential carbon taxes[80]

Mr. Maissan provided the following summary points to support his opinion that:

1. Operating reserve benefit is conservatively underestimated.
2. Diesel and liquefied natural gas (LNG) peak shifting benefit is very likely underestimated.
3. Present fuel costs are not included, net present value (NPV) increases by $1.85 million.
4. Variable operating cost savings are not included, and there is a $94,000 annual benefit for operating reserve only.
5. Hydro operating efficiency gain is not included, and there is an NPV of over $2 million.

[78] John Maissan Final Argument, PDF pages 6 and 7.
[79] John Maissan Final Argument, PDF page 7.
[80] John Maissan Final Argument, PDF page 9.

6. Reduction in Yukon Energy's [YEC's] or customers' costs of outages, not considered.
7. Taxpayer subsidy for carbon tax savings, not considered.[81]

Utilities Consumers' Group

Despite the direction from the government in the Terms of Reference, UCG commented that it was surprised that YEC witnesses at the hearing were not prepared to talk about the ultimate impact on ratepayers.[82] UCG also expressed concerns regarding ineligible costs and the "transfer payment agreement".[83] Further, UCG stated that project costs have significantly increased since the project was first reviewed by the Board in 2018, that costs have changed since the project cost was evaluated by the federal government, and that the current cost range to ratepayers is between $15.2 million and $24.71 million.[84]

The project was not supported by UCG. UCG pointed to the response to JM-YEC-1-33(d) to inform its position that the project puts ratepayers at risk and will likely exceed current cost estimates. In that response, where YEC used a high estimate for project costs, negative benefits were identified for the initial seven years of the project (nearly half the project life).[85]

UCG noted that there was no formal agreement between AEY and YEC for the proposed route, creating the possibility of further unidentified costs for the project.[86]

UCG cited concerns regarding the 25-year site lease, and it noted the option for a further 25-year renewal. It identified additional concerns about the cost impact of such a lease on ratepayers.[87]

UCG submitted that there is no evidence on the record of this proceeding that quantifies or justifies adding the BESS to the YIS or that the BESS Project will result in the hydro generation units being operated more efficiently. YEC confirmed during the hearing that they will have to pay City of Whitehorse taxes on any development on the Kwanlin Dün site and that municipal taxes are on the rise. UCG stated that the property tax impacts of this proposed project over its productive life are another unknown risk that ratepayers are being asked to absorb.[88]

Finally, UCG stated that a 20% overbuild of the BESS Project is a cost component that has not been adequately justified given the uncertainty related to pending proposals from vendors.[89]

[81] John Maissan Final Argument, PDF page 10.
[82] UCG Final Argument, PDF pages 10 and 11, paragraph 56.
[83] UCG Final Argument, PDF page 11, paragraph 57.
[84] UCG Final Argument, PDF page 11, paragraphs 59 and 60.
[85] UCG Final Argument, PDF pages 11 and 12, paragraphs 61 to 64.
[86] UCG Final Argument, PDF page 12, paragraph 66.
[87] UCG Final Argument, PDF page 12, paragraph 67.
[88] UCG Final Argument, PDF pages 12 and 13, paragraphs 69 to 73.
[89] UCG Final Argument, PDF page 13, paragraph 74.

Yukon Energy Corporation

YEC qualified its assessment of risks by stating that the assessment must be based on existing information and estimates, taking into account that final decisions on the BESS Project are still to be made.[90]

The following risk categories were discussed by YEC:

- Technical
- Regulatory
- Capital cost

<u>Technical risks</u>

As discussed in Section 3.2, the first technical risk discussed was operating experience in northern climates. To address this risk, YEC cited similar technology being used in northern Quebec, the Northwest Territories and Alaska. It stated that the size of the system does not impact the ability to operate in the Arctic. By using a self-contained system suited for northern climate conditions and appropriate HVAC systems, implementation issues are reduced.[91] YEC also noted that no issues were raised regarding the lithium ion technology. YEC did add that it will "work with vendors to assess options for ensuring end-of-life capacity".[92]

<u>Regulatory risks</u>[93]

From a regulatory perspective, YEC stated that it does not anticipate material design modifications resulting from the regulatory approvals and review process, no special added costs are expected in order to comply with approvals and permits required, and the key terms for the lease agreement with KDFN have been resolved.

YEC stated that the project followed a public engagement process and public concerns were taken into consideration. The YESAA project proposal was filed with the Whitehorse Designated Office on April 29, 2021. NavCanada and Transport Canada assessment processes review timelines and permitting requirements are well understood and any cost impacts related to required mitigation are expected to be minimal.

<u>Capital cost risks</u>[94]

As stated earlier, YEC's preliminary estimated total capital cost of $31.7 million (2020$, +/-30% accuracy) for the BESS Project includes $16.5 million in funding from the federal government's ICIP, leaving a net capital cost to YEC of $15.2 million to be recovered from ratepayers.

[90] YEC Final Argument, PDF page 14
[91] YEC Final Argument, PDF pages 14 and 15.
[92] YEC Final Argument, PDF page 15.
[93] Taken from YEC Final Argument, PDF page 16.
[94] This section is summarized from YEC's Final Argument, PDF pages 17 to 19.

YEC added that the capital cost estimates provided in the Hatch report were class 4[95] cost estimates, which include a 15% contingency on non-owner costs such as planning. The benchmarks used by Hatch were based on public information or Hatch's in-house data developed through other projects involving Hatch. The Hatch cost estimates were derived based on benchmark pricing of batteries of similar projects, with allocations for project-specific considerations like cold weather, transportation, allocation for installation, and allocation for other electrical and communication components within the BESS. Other capital expenditures were based on engineering costs as well as site preparation costs, which were derived based on estimates from Hatch's civil engineering team.[96]

YEC reiterated that the project would still break even with a 42.5% increase in capital costs, assuming the most recent actual fuel prices. YEC submitted that the BESS Project's capital cost risks will be largely resolved prior to the final stage-gate decision by YEC's board of directors expected in August 2021. YEC submitted that the evidence confirms that the BESS Project has a low level of capital cost risk once that stage is reached.

Board Views

The Board will review the risks associated and impacts to ratepayers regarding the BESS Project for each of the three risk categories identified by YEC.

<u>Technical risks</u>

YEC identified that the technical risk is operating a new technology in a northern climate. YEC submitted that this risk is not large and it cited several examples of BESS-type projects operating in northern climates. As discussed in Section 3.2, the Board notes that generally those projects are of a scale smaller than YEC's proposed BESS Project, they have been in service for three years or less, and they are not planned to be utilized in the manner YEC proposes for the BESS Project.

The Board accepts that BESS-type projects in self-contained units with proper HVAC systems should be able to operate as planned in Yukon. But there are risks; YEC noted certain risks in the hearing.

The YEC witness, Ms. Zuliani, stated that no lithium ion battery has exploded in the Arctic but noted there had been a few fires. She later added that those fires have been reviewed and strategies are ongoing to develop safety protocols, and those are included in Hatch's specifications.[97]

A few fires over a small population size is statistically significant.

---

[95] Class 4 is a level of engineering estimate with an accuracy of +/- 30%. By comparison, a class 5 engineering estimate has an accuracy of +/-50%. (See Transcript Volume 3, PDF page 16, line 19, to PDF page 17, line 3.
[96] Transcript Volume 2, PDF page 52, line 18, to PDF page 53, line 1.
[97] Transcript Volume 3, PDF page 40, line 21, to PDF page 41, line 19.

Although discussed in Section 3.2 of this report, given that there are a limited number of BESS-type projects in northern climates, it appears that there may be a real risk of a fire for a BESS-type project. Hatch has stated that it has developed safety protocols in its specifications, but without the provision of further evidence on the causes of those fires and specifically how Hatch's safety protocols address those causes, this is a risk that YEC, the Minister, the Yukon government, and ratepayers should be aware of.

Further, when questioned by Board counsel regarding thermal O&M costs, Ms. Zuliani stated that Hatch was relying on an experience of less than five projects.[98] Such limited experience introduces technical risk to, and operating costs for, this project.

Another technical concern is the life of the lithium ion batteries proposed for the project. YEC has carefully stated the project has an expected life of up to 20 years with either a modest overbuild at the beginning or an enhancement at the midpoint of the expected life. The Board considers that there is a risk if the life of the batteries fails to sustain for the expected 20 years, and that risk has not been proven abated as none of the battery installations in northern climates have existed beyond 8 years.[99] To mitigate this risk, the Board is of the view that YEC should ensure that there are sufficient safeguards from the vendor to ensure that key performance indicators for such items as battery life, battery failures, and warranties are accounted for in the vendor's obligations in supplying the batteries.

If any of the above technical risks occur, the impact to ratepayers will be higher rates and arguably less reliable service. Such risks, to the extent that they can be reduced by prudent management by YEC of external parties, for events such as battery fires and the service supplied by the battery vendors, will be essential to mitigating the technical risks.

Regulatory risks

YEC stated that it does not anticipate material design modifications resulting from the regulatory approvals and review process. At the hearing, YEC stated that the key terms for the lease agreement with KDFN had been resolved. The BESS Project will be located on land zoned for utility use within an existing environmental and socio-economic setting. The Yukon Environmental and Socio-economic Assessment Act (YESAA) project proposal was filed April 29, 2021. NavCanada and Transport Canada assessment processes are understood, and YEC expects that any cost impacts related to required mitigation would be minimal and within the current cost estimate.

YEC stated that the YESAA, NavCanada, and Transport Canada processes are underway. YEC stated that no further costs with respect to the various regulatory approvals are expected and any cost variances would likely be minimal. However, the regulatory processes are not complete, and

[98] See, e.g., the exchange from Transcript Volume 2, PDF page 60, line 20, to PDF page 62, line 23.
[99] See, e.g., the exchange from Transcript Volume 3, PDF page 40, line 21, to PDF page 42, line 6. YEC identified the oldest project from Alaska which started operation in 2015.

the Board does not have any reliable evidence by which to assess whether there would be any significant ratepayer impacts arising from costs associated with regulatory risks and approvals.

Capital cost risks

YEC provided the following testimony with respect to the estimate of its capital costs for the BESS Project:

> We talked at length this morning about the variability or uncertainty at this time in the capital costs. So the capital cost estimate is provided with a range of plus/minus 30 percent. But then maybe to jump ahead to probably what's the next question is, you know, we've also presented and discussed analyses which then evaluated the ratepayer benefits at the bookends of that risk range, and demonstrated that, even in that plus 30 percent capital cost scenario, there was still a net benefit to ratepayers. So that's one of the -- probably the principal financial risk at this time.[100]

As this is a class 4 estimate (+/- 30% accuracy), there is certainly a risk that the costs for the BESS Project may exceed the $31.7 million estimate. In the past 15 years, YEC has not completed a major capital project that was below the class 4 cost estimate with respect to a Part 3 application, except for when the scope of the project was reduced.[101]

Included in the capital costs are $3.7 million to provide a modest overbuild.[102] YEC has stated that the primary driver for this project is to provide capacity to meet the N-1 criterion in the near term. The N-1 criterion is a one-in-10-year event. Further, YEC has stated that this is a capacity issue and that the YIS does not have an energy shortfall. The theory for this added capacity is that it is there in case of a catastrophic N-1 event. If an event does not occur, then for purposes of the primary criteria, the asset is idle. It is used for backup or other short-term planning purposes.

Therefore, assets used primarily to provide capacity to meet the N-1 criterion are likely to be idle until the N-1 event occurs. YEC is proposing to include an additional 20% to its battery capacity to cover off future degradation of the battery. This seems redundant, as it appears the overbuild is a backup to the backup asset providing N-1 capacity.

YEC has not made a case that justifies spending $3.7 million to overbuild the BESS Project to provide or maintain capacity 10 years down the road. Such costs should be removed from the project unless YEC can provide economic justification for those costs to be included up front.

Nonetheless, as presented in the Application, the submissions of YEC and Mr. Maissan state that several savings opportunities have been either estimated conservatively or have not been included in YEC’s financial analysis. The Board believes that some probability exists in regard to potential savings. The Board is satisfied that, with the 15% contingency included in the cost

[100] Transcript Volume 1, PDF page 124, line 21, to PDF page 125, line 7.
[101] See, e.g., the Carmacks-Stewart Transmission Project, Phase 1, where a substation included in the Part 3 application was subsequently removed from that phase of the project.
[102] YEC responses to YUB IRs, YUB-YEC-1-11(b), PDF page 32.

estimate, unknown items arising from other regulatory processes should be covered within the current estimate.

If YEC's testimony that the prices for containerized batteries are reducing is borne out, that will be shown in the results of the procurement process which will be competitively tendered. If YEC is able to achieve the savings as noted in the Application and elsewhere on the record of this proceeding, then the capital cost risks for this project can be managed by the utility using reasonable judgment.

However, given the margin of error in the class 4 estimates, any recommendations in this report are not a finding of prudency, and in a subsequent GRA when more accurate information is provided, the granting of an energy project certificate and an energy operation certificate will not deem the final project costs prudent. Further, if this project is approved by the Minister and there are changes to the scope of this project, YEC should notify the Minister and the Board about any scope changes that would result in cost increases beyond the 15% contingency or that would materially decrease the capital costs expected for the BESS project.

4.4 Alternatives to the BESS Project — Term of Reference 3.d.

The Minister's Terms of Reference require the Board to make recommendations about the necessity for the BESS Project, among other matters, with particular regard to:

> 3.d. What, if any, reasonable alternatives exist to the BESS Project or what alternative ways of undertaking the BESS Project with its selected technology might be advisable given reasonable load assumptions and risk assessments.[103]

In its Application, YEC referred to its 10-Year Renewable Electricity Plan to address forecast energy and capacity shortfalls, noting that new resources will provide dependable capacity and will generally not displace what the BESS Project option can provide, i.e., the identified permanent resource capacity options are generally all needed to remove reliance on rented diesels and for addressing the forecast capacity shortfall. For example, the Moon Lake Pumped Storage project, when it is developed, is the only identified resource option aside from default new thermal fossil fuel generation, that has the capability to remove the forecast N-1 dependable capacity shortfall.[104]

YEC identified the following alternatives to the BESS Project:

- Standing Offer Program (SOP) and Micro-Generation Program: The SOP is included in the 10-Year Renewable Electricity Plan, which forecasts 40 GWh/year of energy delivered by the IPP sector by the year 2024. The Micro-Generation Policy envisions 6.5 GWh/year of delivered energy by the year 2024. However, no dependable capacity is available from SOP and micro-generation projects because they will be comprised of intermittent renewable resources, such as wind and solar.

[103] Minister of Justice's Terms of Reference, PDF page 3.
[104] YEC Application, PDF page 33.

- Whitehorse Hydro #2 (WH2) and Whitehorse Hydro #4 (WH4) Uprate Projects: These projects increase the efficiency and maximum capacity of the two Whitehorse generation units. However, the capacity increase for WH2 is less than 1 MW, and due to downstream Yukon River system ice flow restrictions, the WH4 does not provide additional dependable capacity.
- Potentially Available Near Term Enhanced Hydro Storage Projects: The Southern Lakes Enhanced Storage Project (SLESP) will expand the storage range on the Southern Lakes system, and the Mayo Lake Enhanced Storage Project (MLESP) seeks to enhance water storage at Mayo Lake. However, both hydro storage enhancement projects would not affect YIS requirements for new dependable capacity.
- Demand Side Management (DSM): DSM involves using incentives, electricity rate structures, and building and appliance codes and standards to encourage customers to reduce the amount of electricity they use. YEC's current focus of the DSM programs is on measures that deliver peak capacity savings (i.e., reductions in peak electricity consumption).
- Diesel Replacement: By replacing retired diesel generator units at existing generation facilities, YEC stated that it can reduce the need for added rental diesel generators. The total replacement diesel currently assumed is 12.5 MW. However, it noted that diesel replacement does not fully address the capacity shortfall.
- The Atlin (Pine Creek) Hydro Expansion Project: In 2020, YEC engaged in discussions with Xeitl Limited Partnership (Xeitl LP) (Taku River Tlingit development corporation) regarding the Atlin project being planned by Xeitl LP and key principles and terms for an Agreement-in-Principle (AIP) for an electricity purchase agreement. Federal funding has been identified as a key requirement for this project to proceed. The objective is for this project to provide 8.5 MW of dependable capacity by 2024/25.
- Tutshi-Moon Pumped Storage Project – Phase 1: This project would provide renewable capacity to address the existing and forecast capacity shortfall under the N-1 planning criterion. YEC stated that this project could potentially provide 35 MW dependable winter capacity starting in the 2028-29 winter season. Federal funding was identified as a critical requirement for this to be affordable for ratepayers and to minimize risks.
- New 20 MW Wind Project: YEC submitted that this project could provide a new 20 MW wind resource in 2025/26 to meet the higher energy requirements over the planning period. This resource option would not provide dependable capacity.

YEC summarized its position by stating that no feasible renewable resource alternatives to the BESS Project have been identified within the expected time period for completion of the project and that the temporary rented diesel option or permanent new diesel development remain the only feasible alternatives to provide dependable capacity to meet the utility's requirements.[105]

Yukon Conservation Society

YCS did not discuss this aspect of the Minister's Terms of Reference.

John Maissan

John Maissan stated that the only reasonable alternative to the BESS Project is a 20 MW or larger diesel thermal generation plant as noted in the past LNG project proceeding. In Mr. Maissan's view, in the public consultation on a proposed new thermal plant, the public opposition to such a project would be significant. Mr. Maissan added that a thermal alternative is also contrary to Yukon government policy, citing YEC's response to information request YUB-YEC-1-1 (f) and (g). Further, Mr. Maissan noted that a thermal plant must be diesel rather than LNG because diesel generators have a much better ability to restore the grid from outages, and that a thermal plant would not provide ratepayers with the savings from reduced thermal generation the way that the BESS Project can. Nor would a thermal plant provide the reliability, load loss stabilization, and black start and outage restoration benefits that the BESS Project provides. Mr. Maissan concluded that a diesel thermal plant is not an advisable alternative to the proposed BESS Project given that a thermal plant would lack the financial and other benefits that the BESS will provide.[106]

Utilities Consumers' Group

UCG stated that YEC confirmed it was YEC's board of directors that decided not to pursue a permanent solution to the capacity gap on the YEC system (i.e., a large new permanent diesel) and instead instructed management to focus on renewable projects. UCG submitted that this direction prevented the consideration of diesel- or LNG-fueled generation alternatives to the BESS Project.[107] UCG added that a capacity shortfall arose because YEC did not previously establish a plan to pursue overhauling all of their diesel generators as they were retired. If YEC had established an efficient plan of thermal plant overhaul and replacement, UCG argued that YEC would not find itself in the position of having to use and replace rented diesel generation equipment and having N-1 capacity backup issues.[108]

---

105 YEC Application, PDF pages 33 to 35.
106 John Maissan Final Argument, PDF page 10.
107 UCG Final Argument, PDF page 14, paragraph 78.
108 UCG Final Argument, PDF page 14, paragraph 79.

Yukon Energy Corporation

In its final submission, YEC stated that the BESS Project provides 7 MW of dependable N-1 capacity on a timely basis, with benefits not available through other alternatives.[109] Couching its position in terms of not relying on new fossil fuel alternatives and near-term renewable resource alternatives, YEC said there were no reasonable alternatives to the BESS Project and that a new 20 MW thermal plant is not a viable option.[110] YEC added that maintaining the status quo is also not a viable option and permanent solutions are needed.[111] Aside from the Atlin Hydro and Moon Lake Pumped Storage projects, temporary rental diesels or a permanent new thermal development remain the only feasible alternatives that would provide the dependable capacity required to address the N-1 dependable capacity shortfall. The BESS Project's operating reserve use benefits enable it to provide material ratepayer cost savings relative to both the diesel rental and permanent thermal alternatives.[112]

YEC stated, with respect to longer term projects, that the two dependable capacity hydro renewable projects identified for development within 10 years are each subject to securing material federal grant funding and, even if they are developed, they will not remove the ongoing need for the other dependable capacity projects such as the BESS Project.[113]

Board Views

The Terms of Reference require recommendations on reasonable project alternatives or alternative ways of undertaking this project. It is clear from the submissions of all parties that some form of diesel generation is the only viable alternative to the BESS Project, at least in the near term. In the oral hearing, two YEC witnesses noted that the benefit to the BESS Project is operating reserve, as demonstrated by the following testimony:

> … N-1 is a one-in-10-year event. So it's really important to keep in mind, you have to look at the costs of the alternatives, where they're spending most of their time just sitting there not doing anything, as well as other use cases, which we presented in that table when we talk about the operating reserve, used savings, and the peak shifting uses. So it's not just the N-1 that justifies the project.[114]

In the Application, YEC submitted its alternatives to the BESS Project but stated that no feasible renewable resource alternatives to the BESS Project have been identified within the relevant time period and that the temporary rental diesel option or permanent new diesel development remain

---

[109] YEC Final Argument, PDF page 19.
[110] YEC Final Argument, PDF page 20.
[111] YEC Final Argument, PDF page 20.
[112] YEC Final Argument, PDF page 19.
[113] YEC Final Argument, PDF page 20.
[114] Transcript Volume 3, PDF page 31, lines 6 to15.

the only feasible alternatives.[115] YEC identified some of the facilities projects in its 10-Year Renewable Electricity Plan as alternatives.

YEC has been renting diesels to cover its capacity shortfall. A YEC witness stated in testimony regarding the planning respecting the capacity shortfall: “So we plan, essentially, for N-1 once every 10 years. That's what we anticipate the frequency to be.”[116]

The rental option to cover capacity shortfall is the status quo option. YEC started renting diesels for the 2018-19[117] winter peak and it expects to continue renting diesels up to and including the 2028-29 winter peak.[118] YEC expects diesel rental costs to continue for 10 years.

Rental or purchased diesel units

The issue of rental or purchased diesel units is also discussed in Section 3.1 of this report. YEC compared the BESS Project to the rented diesel alternative, and based on this comparison, YEC concluded that the BESS Project was economically superior[119] and met the primary criteria N-1 capacity shortfall.

When asked whether there were any operational concerns with the continued use of rented diesel fuel generators and the economics of the two alternatives, YEC stated that it looked at the capacity gap, the expected length of the capacity gap, and future plans to bring capacity additions online. In YEC’s view, through that assessment, the rental of diesels was a viable solution. Operationally, however, since that assessment, YEC has learned that the rental units are not always available, and so two additional spares are required. [120]

YEC witness testimony provided additional insight into the utility’s reasoning, and some of these reasons are summarized below:

- The rental diesel units are not as reliable as YEC would like them to be.[121]
- Rental units are not perfectly configured for utility service. The decision for rental of diesel units versus the decision for permanent purchase are quite different.
- If YEC were investigating the specifications for something to place on the YIS that it absolutely needed to have because they're there for the N-1, it would not look at something that had the kind of use history that the rental units have.
- The alternative would be to look at a permanent diesel facility, i.e., larger facility options.[122]

[115] YEC Application, PDF page 35.
[116] Transcript Volume 3, PDF page 55, lines 23 to 25.
[117] YEC consolidated responses, YUB-YEC-1-17(c), PDF page 158.
[118] Transcript Volume 1, PDF page 173, lines 4 to 10.
[119] E.g., see YEC Application, PDF page 43, Table 4-3, Annual Ratepayer Impacts from BESS.
[120] Transcript Volume 1, PDF page 86, lines 3 to 23.
[121] Transcript Volume 1, PDF page 123, lines 18 to 23.

YEC's Application and testimony support that the rented diesels are not a preferred alternative to the BESS Project. The BESS Project has a higher levelized cost of capacity than rented diesel units.[123] However, YEC states that the BESS results in a net present value benefit to ratepayers and the BESS is expected to offset the use of four diesel units. On review of the record, YEC has sufficiently demonstrated that the BESS Project is a preferred alternative to rental diesel units.

Diesel (thermal) plant

Another alternative to BESS is to construct a new diesel plant. This is also discussed in Section 3.1 of this report. In a previous Board Order, the Board found that YEC has supported its case that added capacity is needed to meet system reliability needs under the N-1 criterion and that a greenfield thermal generation plant is one of the preferred methods to add the needed capacity.[124]

In response to an IR in this proceeding, YEC stated:

> The YUB reviewed planning for the new 20 MW diesel plant project during the 2017/18 GRA, and noted in Appendix A to Order 2018-10 that it was not persuaded that the project was the only way to address the predicted capacity shortfall, and that YEC should not proceed with the project without a detailed business case that considers the alternatives to the project.[125]

YEC did not correctly summarize the Board's views. The Board's comments were not a condemnation of building a 20 MW diesel plant project; rather, the Board was reminding YEC that it should provide a business case with adequate support for the project.

In the Board's view, YEC did not fully consider the acquisition of purchased diesel as an alternative to compare with the BESS Project, partly because of direction from its board of directors to focus on renewable options. Some social license considerations were engaged as well. As a result, the benefits and costs of purchased diesel were not examined in detail to discount a new diesel plant as an equal or preferred alternative. YEC noted that one particular advantage of the BESS Project over diesel was that "it has almost instantaneous ability to ramp to full output; whereas a new diesel plant can take several minutes to ramp up. And so, a BESS has a much greater ability to keep the grid stable and operating versus a diesel engine."[126]

Although it is not YEC's preferred alternative, YEC confirmed in testimony the ability of diesel to mitigate loss from N-1 events. YEC confirmed that both the BESS and a diesel alternative are appropriate solutions to meet N-1 criterion, but the BESS provides a faster solution to prevent a blackout. Both would work equally well over a longer duration event. [127]

[122] Transcript Volume 2, PDF page 43, line 21, to PDF page 44, line 2.
[123] YEC Application, PDF page 21.
[124] Appendix A to Board Order 2018-10, PDF page 94.
[125] YEC consolidated responses, YUB-YEC-1-37(b), PDF page 255.
[126] Transcript Volume 1, PDF page 159, lines 3 to 14.
[127] Transcript Volume 2, PDF page 38, line 3, to PDF page 40, line 8.

Further, in response to an IR, YEC showed that the levelized cost of capacity for the purchase of a diesel plant was less than that of the BESS option.[128]

If diesel is to provide capacity for a one-in-10-year event (N-1), then the generation unit would likely be idle most of the time. This means there should be less environmental implications from an emissions perspective as compared to diesel that is always running. YEC also did not investigate or state whether government funding would be available for a new diesel plant.

Despite these limitations, it is the Board's recommendation that the Minister can consider that YEC explored alternatives to the BESS Project, and YEC has provided a sufficient economic basis for the BESS Project to proceed compared to the alternatives identified by YEC. The Board has provided its views on a diesel plant for additional capacity because there are benefits to this alternative, particularly from an economic perspective, and considers that a diesel plant should not be disregarded by YEC's board of directors as a viable alternative to meet future system capacity. In reviewing the totality of the evidence, the Board is satisfied that the Minister can accept that the BESS Project is an acceptable and economic alternative as part of YEC's system planning for generation.

Location

In addition to reasonable project alternatives, the Terms of Reference ask about alternative ways of undertaking the project. The Board considers alternative siting to fall under this category. The Board notes that requiring the project to be located on settlement land, and having only one option outside city limits which ultimately was not selected, may have resulted in additional and material costs to the ratepayer. The selected location within municipal boundaries includes approximately $6 million to $7 million[129] in municipal taxes over the life of the project.

Alternatively, there may have been appropriate locations that do not involve lease costs or tax costs that were not sufficiently explored — for example, the unoccupied Crown land adjacent to the Takhini substation. Choosing a location on First Nation settlement land within the City of Whitehorse may have eliminated lower cost options.

[128] The table in response to YUB-YEC-1-30 (PDF page 231 shows the estimate LCOC of a diesel purchase to be $186/MW compared to $235/MW for BESS. YEC provided an update to this in undertaking #7, however those costs and assumptions were not tested nor did YEC explain why such scrutiny was not provided for the original IR response given that a comparison between BESS, rented diesel and purchased diesel were requested. Nor did YEC consider the sale of the purchased diesel when N-1 capacity criteria is met through other renewable energy projects identified by YEC to occur in subsequent periods.
[129] Transcript Volume 3, PDF page 36, line 12, to PDF page 37, line 1.

4.5 Impacts of the Debenture Investment Opportunity on YEC and Ratepayers — Term of Reference 3.e.

The Minister's Terms of Reference requested the Board to report on and make recommendations about the necessity for the BESS Project, among other matters, with particular regard to:

> 3.e. Impacts on YEC and ratepayers of the debenture investment opportunity that YEC is providing to TKC and KDFN in recognition of the BESS Project's location on the overlapping Traditional Territory of TKC and KDFN and the benefits of TKC and KDFN support for this Project's development at this time.[130]

YEC's Application noted that YEC engaged both First Nations (TKC and KDFN) in quarter 2 of 2020 and a trilateral committee was formed:

> "…for sharing Project information, assessing three alternative KDFN and TKC sites for the Project, and negotiating benefits for both First Nations from the Project. The Project Committee met regularly thereafter in 2020 with a particular focus on the work required to recommend a preferred site and to review a draft Term Sheet that evolved to include a debenture investment opportunity for both TKC and KDFN based on 25% of the equity portion of YEC's net rate base cost of the BESS project."[131]

YEC stated that First Nation debenture investment for facilities projects have occurred for past facilities. However, in the past, the debenture investment opportunities were made with Yukon Development Corporation and were therefore not subject to Board review.

For the BESS Project, the investment opportunity is being made directly with YEC. YEC added that, although there is no legal requirement to provide any First Nation with an investment opportunity related to the specified YEC facilities projects, past investment opportunities have been, or are currently, generally provided as part of First Nation engagement, involvement, and support for the project's development.

The debentures or details of the agreements with KDFN and TKC were not available for the Board's review because not all negotiations and agreements with the First Nations had been finalized. YEC expected that the debenture agreement itself would be a straightforward document.[132]

In addition, YEC summarized the key terms to the First Nation debenture investment in the Application as:

> 1. KDFN and TKC will each be offered the opportunity to provide a loan to YEC in accordance with the following principles:
>
>> a. YEC's Net Rate Base Cost for the Project is YEC's final capital cost for developing the Project less any funding contributions to YEC for the Project and any costs disallowed by the YUB from inclusion in rates.

[130] Minister of Justice's Terms of Reference, PDF page 3.
[131] YEC Application, PDF page 22.
[132] Transcript Volume 2, PDF page 82, line 20, to PDF page 83, line 2.

b. The BESS Equity Cost is 40% of the Net Rate Base Cost and reflects the portion of the Net Rate Base Cost that is financed by YEC equity.

c. KDFN and TKC will each be offered the opportunity to provide a Loan Investment of up to 25% of the BESS Equity Cost. The following example outlines the process, assuming a final BESS net rate base cost of $15.2 million after grants:

i. Assuming YUB approval of these costs, YEC's Net Rate Base Cost would be $15.2 million and this would be funded by 40% equity [the BESS Equity] of $6.1 million and by 60% long-term debt of $9.1 million.

ii. KDFN and TKC would each have the opportunity to provide a Loan Investment of up to $1.52 million, i.e., each up to 25% of the $6.1 million BESS Equity Cost.

2. The Loan Investment opportunity will be available for a specified period after the Project is in service and YEC's final net rate base (after contributions and YUB review) is determined by YEC and communicated to KDFN and TKC.

3. The term for each Loan Investment will be based on the remaining portion of the expected asset life.

4. YEC will provide the following annual payments to KDFN and TKC with regard to each of KDFN and TKC's Loan Investment:

a. Repayment of principal at equal annual amounts over the Term; and

b. An annual return on the Loan Investment balance then applicable times YEC's actual final rate of return on equity (actual percentage return for a completed fiscal year) for YEC's utility regulatory income for the completed fiscal year most recently filed with the YUB (YEC's last approved equity return included in rates is 8.70%).[133]

YEC added that the debentures would be treated as long-term debt given the nature of the financial instrument. Noting that the equity return paid on this instrument is well above the market rate for long-term debt, for the purposes of rate-making, YEC would treat this investment as equity to maintain the 60:40 debt-to-equity capital structure for YEC that the Board has previously approved. To maintain YEC's debt-to-equity ratio, YEC committed to execute the necessary transactions with YDC to maintain the 60:40 ratio on an annual basis.

YEC advised that any rate applications to the Board will show this debenture as a component of equity for revenue requirement determination, thereby causing no net impact to ratepayers from this transaction.[134]

[133] YEC Application, PDF pages 22 and 23.
[134] YEC Application, PDF page 23.

Yukon Conservation Society

YCS did not provide submissions on this issue.

John Maissan

John Maissan stated that the evidence indicates that the debenture investment opportunity has no impact on YEC or on the ratepayers of Yukon. He submitted that he was in full support of this opportunity and YEC decisions to contribute to these efforts by locating the BESS Project on a very suitable parcel of KDFN land. He recommended that the Board support this debenture investment opportunity in its report to the Yukon government.[135]

Utilities Consumers' Group

In its final submission, UCG expressed several concerns with the debenture investment opportunity.

UCG was concerned that YEC only considered First Nation land with the goal to create an opportunity for a land lease with the First Nations.[136] It submitted that YEC failed to do a proper market review of available locations and properly consider the costs of such decisions on ratepayers.[137] UCG disagreed with YEC's position that the land "is not a factor because YEC is using market-based costs so ratepayers would be indifferent because they would pay the same whether it was on settlement land or not."[138] UCG submitted that, given that YEC does not know what costs will ultimately be imposed by the First Nations or what type of longer term commitments will be put in place, there will be a cost burden to ratepayers due to this decision by YEC.[139]

Regarding the debenture investment opportunity, UCG stated:

> UCG questions YEC's claim that the First Nation debenture investment proposed for this project will enable Yukon First Nation investment without any impact to ratepayers. The fact that the net benefits to Yukon ratepayers could easily be negative for the majority of the life of the proposed BESS is obviously a negative impact on ratepayers no matter how YEC spins the form of Yukon First Nation investments.[140] (Footnote removed)

UCG also submitted that YEC implied that the cost of the First Nations' benefits will be in excess of the $100,000 identified in the project budget outlined in Schedule B of the Transfer Payment Agreement because the project budget far exceeds the $25 million assumed in the Transfer Payment Agreement.[141]

[135] John Maissan Final Argument, PDF pages 10 and11.
[136] UCG Final Argument, PDF page 15, paragraph 87.
[137] UCG Final Argument, PDF page 15, paragraph 88.
[138] UCG Final Argument, PDF page 15, paragraph 89.
[139] UCG Final Argument, PDF page 15, paragraph 89.
[140] UCG Final Argument, PDF page 16, paragraph 94.
[141] UCG Final Argument, PDF page 16, paragraph 95.

UCG finalized its position on this issue by concluding:

> While YEC testified that it is "very hard" to find a development site that's actually better situated or on Crown land, that doesn't mean that more time shouldn't be put into keeping site-related costs as low as possible. It appears YEC is trying to avoid taking the time necessary to fully examine all options available. The unknown impact over the next couple of decades of property taxes (starting at $7 million) is a significant issue for ratepayers.[142] (Footnotes removed)

Yukon Energy Corporation

In its final submission, YEC stated that "First Nations' support for the Project is important given its location and YEC's desire to provide economic benefits to First Nations."[143] YEC also added that the "BESS Project is the first time when Yukon Energy - rather than Yukon Development Corporation - is providing a debenture investment opportunity in a YEC project"[144] and that the opportunity closely aligns with YDC's precedent on other Yukon projects such as Mayo B and the Whitehorse LNG.

YEC added that the debenture is a loan and that the return to the lender will be based on YEC's actual return on equity and will be included in YEC's equity return for rate setting purposes. YEC witnesses testified that there will be no impact on ratepayers.[145] Finally, YEC submitted that there will be an opportunity for the Board to review BESS Project costs including the debenture costs prior to those costs being included in rates.[146]

The nature of the debenture investment opportunity is best described as:

- Not a traditional loan in that YEC would not normally require a debenture with a rate based on its return for equity.
- Structured as a traditional loan instrument. Equity components are normally provided by the shareholder, YDC, through direct investment or accumulated earnings.
- The debenture investment opportunity does not create an ownership interest for the two First Nations.
- Historically, YDC entered into these kinds of transactions with First Nations on prior YEC projects. YDC did not have the ability to enter into this type of transaction this time.

---

[142] UCG Final Argument, PDF page 16, paragraphs 96 and 97.
[143] YEC Final Argument, PDF page 24.
[144] YEC Final Argument, PDF page 25.
[145] YEC incorrectly referenced page 125 of the transcripts, whereas the testimony from Mr. Mollard started at Transcript Volume 1, PDF page 135, lines 7 to 12. Further testimony occurred at Transcript Volume 2, PDF page 86, lines 2 to 13.
[146] YEC Final Argument, PDF page 25, and Transcript Volume 2, PDF page 85, line 24, to PDF page 87, line 22.

- The YEC board of directors made the decision for YEC to enter into this type of transaction with the understanding that the Board would approve this type of transaction.[147] [148]

Board Views

The Minister asked the Board to assess the impacts on YEC and ratepayers of the debenture investment opportunity that YEC is providing to TKC and KDFN in recognition of the BESS Project's location on the overlapping traditional territory of TKC and KDFN and the benefits of TKC and KDFN support for the BESS Project's development at this time.

During the hearing, the Board asked questions about the selected location and possible impacts on ratepayers. The Board agrees that situating the BESS Project on First Nation land, from a cost perspective, may lead to higher costs for ratepayers than would otherwise occur through obtaining land competitively in the market or situating it on Crown land outside of the limits of the City of Whitehorse. Situating it within the City of Whitehorse will result in additional tax costs.

The Board notes that UCG was the only participant that raised concerns about YEC considering only First Nation settlement land or the debenture investment opportunity for the BESS Project. It did so from an economic and ratepayer perspective.

YEC also stated that, from its perspective, structuring the arrangement as debenture is a benefit to the First Nations and that ratepayers will be indifferent, i.e., the debenture agreement will not harm or benefit ratepayers.[149]

With YEC as the counterparty to the debenture agreement, YDC is still directly impacted by such an agreement.[150] The Board would highlight to the Minister that it does not have transparency into the agreement with the KDFN and TKC and is relying on YEC’s summary of key terms of the arrangements with the two First Nations for a debenture investment for the purpose of this report.

In general, a debenture is a debt instrument that pays interest at a higher rate than YEC’s average long-term debt. The Board considers that the reasonable consequence of YEC’s willingness to allow for adjustments that would be approved by YDC may result from a lower return on YEC’s other net rate base to enable this debenture agreement to ensure that YEC maintains a 60:40 debt/equity ratio. From a purely regulatory perspective, it would be more accurate and simpler to treat the return on the debenture in excess of YEC’s average cost of long-term debt as a disallowed expense, effecting the same net result to YDC’s return while maintaining the overall integrity of YEC’s accounting. It appears from the Application that YEC is willing to take on the

[147] Transcript Volume 2, PDF page 81, line 8, to PDF page 82, line 7.
[148] Transcript Volume 1, PDF page 135, lines 5 to 12.
[149] Transcript Volume 1, PDF page 135, lines 5 to 12.
[150] As noted by Mr. Mollard, YDC would be affected by either direct investment or accumulated earnings.

risk of a lower return on the other assets in order to undertake the BESS with TKC and KDFN involvement.

The accounting treatment of the debenture investment opportunity and associated costs to ratepayers are issues best addressed in a GRA. Based on the testimony of YEC's witnesses, the Board accepts YEC's commitment that ratepayers will not be adversely impacted by the debenture investment opportunity. On balance, the Board does not object to the debenture agreements, nor will it recommend any conditions on the debenture agreement, but it will carefully scrutinize YEC's commitment that the debenture agreements will not impact YEC's ratepayers, i.e., that the costs from the debenture arrangements are rate neutral. Conversely, the effect of only situating the BESS Project on First Nation land, from a cost perspective, may lead to higher costs for ratepayers than would otherwise occur through obtaining land competitively in the market.

The cost or benefit to ratepayers as a result of using First Nation land compared to privately procured land (outside municipal boundaries) or Crown land is unknown at this time. The Board is of the view that, since the land has not been openly procured, any potential premium paid for the use of the land, or additional costs for the transaction beyond a competitive market range, should be borne by the shareholder, YDC.

The costs for the land lease part of the project are not as significant as the other capital costs for the BESS Project, and as stated above, further review of the costs will occur in a future GRA before the Board. In these circumstances, the Board accepts the use of a debenture agreement between YEC and First Nations; however, YEC is expected to reflect the fact that it is a debt instrument in any regulatory filing with this Board. Further, YEC shall separately show the premium it is paying for this long-term debt relative to its other existing long-term debt in its future GRA applications and shall also show that the premium is not being recovered from ratepayers. The Board is of the view that, for future facilities projects, it is preferred that Yukon Development Corporation — as YEC's parent — be the contracting party for debenture agreements, as has been done for past Part 3 applications.

4.6 Building the BESS Project at this Time — Term of Reference 3.f.

The Minister's Terms of Reference requested that the Board report on and make recommendations about the necessity for the BESS Project and its timing and design, with particular regard to:

> f. Whether it is prudent to build the BESS project as proposed at this time.

Yukon Energy Corporation

YEC submitted it was the right time to build the BESS Project because it had secured government funding, reducing the costs that will be required to be recovered from ratepayers. YEC also highlighted the need for the BESS Project in mitigating capacity shortfall concerns and avoiding the rental of four diesel units. YEC submitted that ratepayer benefits would accrue starting in year 1 of the project. YEC advised that the BESS Project would contribute to meet the growing dependable capacity requirements, directly reduce YEC's reliance on thermal generation, provide cost savings for ratepayers, and increase the reliability of electricity service to customers.

Yukon Conservation Society

YCS agreed that building the BESS Project is prudent at this time because it would eliminate the need to rent four diesel units and make the YIS more capable of delivering lower emission electricity to customers. YCS also stated that the ratepayer savings forecasted by YEC was conservative in nature, as it did not include volatility in diesel fuel prices in the future and the potential of applying a carbon tax to northern jurisdiction electricity providers.[151]

John Maissan

Mr. Maissan also agreed with the prudency aspect of the BESS Project, indicating that the information provided on the record strongly supported completing the project at this time. Mr. Maissan reiterated that YEC was conservative in its estimation of the benefits and agreed that the project would provide ratepayer benefits starting from year 1. Mr. Maissan also submitted that the reliability benefits were significant, even though they were not accounted for in the financial information for the project.[152]

Utilities Consumers' Group

UCG did not believe building the project was prudent at this time. It referred to Board Order 2018-10 in which the Board noted several risks and concerns with pursuing a grid-scale BESS Project, including concern that the technology had not been demonstrated in a northern climate. While UCG acknowledged that YEC made reference to BESS-type projects operating in northern Quebec and the Northwest Territories, UCG expressed concern that YEC did not address how successful these projects had been in achieving anticipated benefits and if any issues had arisen with these BESS installations. UCG submitted that YEC had not provided specific information regarding these other northern projects. UCG disagreed with YEC's position that information regarding costs, alternatives considered, or operating experience with these other projects would not provide any material assistance to the Board in its review of this Application.[153]

Board Views

Consistent with the Board's views provided in Sections 3.1 and 3.2 of this report, the Board finds there is a need for the BESS Project. In addition, YEC's funding procured from the federal government for the BESS Project makes it more affordable for ratepayers.

However, the Board does not consider it appropriate at this time to respond to the Minister's request for a recommendation on whether it would be prudent to build the BESS Project as proposed. The question of prudence is a key criterion that the Act requires the Board to apply in

[151] YCS Final Argument, PDF page 6.
[152] John Maissan Final Argument, PDF page 11.
[153] UCG Final Argument, PDF pages 16 and 17.

considering GRAs, and if the Board were to comment on the prudence of the BESS Project outside of GRA proceedings, any such comments could be challenged as prejudging matters that are best left for a GRA decision.

In any event, and as discussed earlier in this report, the uncertainties and insufficiency of information upon which the BESS Project proposal is predicated do not provide the Board with sufficient evidence on which to make an assessment of prudence, even absent the constraint mentioned above.

For these reasons, the Board declines to make any recommendation in response to subparagraph 3.f. of the Terms of Reference.

5. BOARD FINDINGS AND RECOMMENDATIONS

<u>Specific aspects of the project to be reviewed</u>

The Terms of Reference required the Board to report on, and make recommendations about, the necessity for the BESS Project and its timing and design (Section 3). A summary of the Board's findings on specific aspects of the project to be reviewed, as identified in the Terms of Reference, are as follows:

> 3.a. The public need for the BESS Project under various reasonable electric load forecasts, including near-term requirements related to industrial and non-industrial loads, and the effect of the Project on the rates of customers and the reliability of electricity service provided to customers.

- The Board finds a near-term need for the BESS Project.
- Given that the BESS Project is in a preliminary stage, there are too many uncertainties for the Board to make a recommendation on the effect of the BESS Project on final rates.
- The BESS Project can provide operating reserve for the grid when excess water is available.

> 3.b. The capability of existing and currently committed and expected generation and transmission facilities, including thermal generation facilities, to provide reliable electric power generation to meet the forecast load requirements and YEC's capacity planning criteria and the effect of the BESS Project on this capability.

- The Board accepts that the BESS Project would contribute to reliable electric power supply to meet the forecast future load requirements.
- From the information that has been presented on this record, the Board is satisfied that the project will not hinder existing and currently committed (and expected) generation and transmission facilities. The BESS Project will provide N-1 capacity support, operating reserve support, and increased grid reliability.

3.c. The risks for the BESS Project and their potential impacts on rates for customers and on the reliability of electricity service provided to customers.

- The technical risks include a real risk of fire and a risk that the battery life of the lithium ion will not last 20 years.
- The Board does not find sufficient evidence to support YEC's assertions that there would be no significant ratepayer impact from costs associated with YESAA, NavCanada, and Transport Canada regulatory risks and approvals.
- As the BESS Project is a class 4 estimate (+/- 30% accuracy), there is a risk that the costs for the BESS Project may exceed the $31.7 million estimate.

3.d. What, if any, reasonable alternatives exist to the BESS Project or what alternative ways of undertaking the BESS Project with its selected technology might be advisable given reasonable load assumptions and risk assessments?

- Diesel generation is the only viable alternative to the BESS Project in the near term.
- The Board finds that the BESS Project is a preferred alternative to rental diesel units and an acceptable alternative to a new diesel plant.
- An alternative way of undertaking the BESS Project would include considering locating the project outside the City of Whitehorse.

3.e. Impacts on YEC and ratepayers of the debenture investment opportunity that YEC is providing to TKC and KDFN in recognition of the BESS Project's location on the overlapping traditional territory of TKC and KDFN and the benefits of TKC and KDFN support for this Project's development at this time.

- The Board accepts YEC's commitment that ratepayers will not be adversely impacted by the debenture investment opportunity.
- The effect of YEC's decision to only consider situating the BESS Project on First Nation settlement land, may lead to higher costs for ratepayers than would otherwise occur through obtaining land competitively in the market.

3.f. Whether it is prudent to build the BESS Project as proposed at this time.

- Any comment or recommendation the Board may make about the prudence of the BESS Project at this time could, in effect, prejudge what it is statutorily required to be considered at GRAs. Therefore, the Board declines the opportunity to make any such comments at this time.

Recommendation respecting certificates

The Terms of Reference state that the Board shall provide a recommendation on whether YEC should be granted an energy project certificate and an energy operation certificate for the BESS Project and, if so, whether the certificates should be subject to any terms and conditions and what these terms and conditions should be (Section 5).

Based on the above findings, the Board recommends that YEC be granted an energy project certificate and an energy operation certificate. There is a public need for the BESS Project, and the project would allow YEC to install new capacity with some other potential system benefits. The Board notes that the evidence that the BESS Project would result in savings to ratepayers is incomplete and inconclusive. As such, all estimates must be treated as preliminary. Any resultant savings and ratepayer impact cannot be determined at this time.

Making a recommendation about ratepayer impact at this stage in a process, with so many outstanding costs, is difficult. This is why the Board has put a great deal of emph asis on the prudence review of costs at future GRAs. The Minister will have to consider whether requiring additional transparency to the government, such as quarterly reporting to the Minister, is warranted before the final costs of the project are submitted to the Board for review in a GRA.

Other recommendations

The Terms of Reference state that the Board may make any other recommendations or provide any other information that it considers advisable in the circumstances (Section 6). As noted in Section 2.1, the Board recommends that Ministerial approval of this project, if granted, is informed by governmental and other public policy issues outside of the Board's jurisdiction as an economic regulator. Specifically, decision-making criteria related to First Nation economic development opportunities and climate change concerns are beyond the Board's authority set out under the *Public Utilities Act*.

ISSUE:

REFERENCE: **Application, Table 4-1, page 20, PDF page 23Issue: Non-industrial peak and dependable capacity**

QUOTE:

QUESTION:

a) Under the category “Non-industrial Peak”, please explain what “EV Peak” is.

b) Under the category “N-1 Event”, please explain the inclusion of “Loss of AEY Haines Junction diesel” and “Haines Junction peak”.

ANSWER:

(a)

EV Peak relates to the peak demand forecast related to electric vehicle use. It is a specific load forecast growth element addressed in Table 2 of YEC’s 10-Year Renewable Electricity Plan (see YUB-YEC-1-32, Attachment 1).

(b)

On the YIS, Haines Junction is supplied by a single feeder from the Aishihik Hydro station. Therefore, during an N-1 event (loss of the Aishihik plant or transmission line), YEC would be unable to supply the load at Haines Junction nor can YEC rely on the local diesel, so both are excluded from the calculation.

ISSUE: **Historical records**

REFERENCE: **Application, footnote 34, page 22, PDF page 25**

QUOTE: "See Section 2.1.3 of this Submission. The LTA energy generation estimate for the Project deliveries to YEC was prepared by SNC Lavalin, retained by THELP, based on available historical water records (1963-1993; 2015-2019) as reviewed in Appendix A, Table A1. The Project LTA energy generation in Appendix A, Tables A1 and A3-1 for winter deliveries to YEC at Jakes Corner reflects the average Atlin Project hydro generation during the Winter Period (Jan. 1 to May 31, Sept. 1 to Dec. 31) for all water records, while the low water year winter generation deliveries reflect the lowest hydro generation in water year 1978. The transmission losses between the Atlin generation location and delivery point at Jakes Corner is estimated to be at around 2.7%. Additional losses are added that reflect losses in YIS system which is assumed at 6.2% based on losses approved for ATCO Electric Yukon in its most recent GRA (assumes AEY System Upgrades will result in continuation of past average losses despite the material increases in energy being transmitted on this system)."

QUESTION:

a) Why are historical water records from 1994-2014 not included in the LTA energy generation estimate?

b) How accurate is the assumption that, with higher load, the assumed AEY System Upgrades will result in the continuation of past average losses? Please explain the basis for the assumption.

ANSWER:

(a)

YEC understands that adequate historical water records are not available from 1994-2014. The initial feasibility studies on this Project prepared for THELP by Morrison Hershfield and KGS Group were able to develop a flow and power hydrological simulation model for

Pine Creek flows based on comparison to Gladys River area's nearly complete 32 years of recorded flows by Water Survey of Canada from 1964 to 1993. It was concluded that the 30 year synthetic flow series from the Gladys River provides a reasonable estimate for long-term flows in Pine Creek. The feasibility study was also able to utilize monitoring initiated in September 2014 of Pine Creek catchment flows.

(b)

The 6.2% losses assumed for AEY transmission reflect historical information, and variances are expected after AEY System Upgrades and addition of the Atlin deliveries. However, the AEY design for System Upgrades assumed Atlin deliveries at 10.575 MW (i.e., higher than the EPA allowed maximum of 8.5 MW) and reflected the need to ensure expected AEY losses do not exceed 8.8%. Final selected AEY Systems Upgrades design and Atlin load will affect the extent to which actual losses are materially below the 8.8% design limit.

ISSUE: **Unknown reference**

REFERENCE: **Application, page 24, PDF page 27**

QUOTE: "The BESS and the Project each can reduce the need for rented diesels – however, the Moon Lake pumped storage project, when developed in combination with BESS and the Project (as well as other developments assumed in Table 3-1), is the only identified resource option aside from default new thermal generation that has the capability to remove the forecast N-1 dependable capacity shortfall and reliance on rented diesels."

QUESTION:

a) Table 3-1 is entitled "Summary EPA Energy and Capacity Pricing". What developments is YEC referring to in Table 3-1, or what table should YEC be referring to related to the above quote?

ANSWER:

(a)

The above quote includes a typo. The reference to Table 3-1 is incorrect. The correct reference is Table 4-1: Forecast Non-Industrial Peak and Dependable Capacity under N-1 Capacity Planning criterion: 2021/22-2030/31 Winter (kW).

ISSUE: **Rented diesels**

REFERENCE: **Application, page 24, PDF page 27**

QUOTE: "The only other alternative identified to date for meeting the capacity shortfall without rented diesels would be to develop additional permanent thermal (diesel) capability beyond the planned replacements of retired units. As reviewed in the BESS proceeding, the development of new permanent diesel plants is not supported by stakeholders and is also not in line with goals outlined in Yukon government's draft 'Our Clean Future: A Yukon strategy for climate change, energy and a green economy.' As reviewed in Section 4.2 below, EPA impacts on customer rates are designed to mirror or improve upon the impacts to be expected with a permanent thermal generation option."

QUESTION:

a) Explain the steps YEC took to review and the analysis undertaken regarding the diesel rental option.

b) Describe the steps taken and analysis performed regarding the purchase of a larger diesel option (for example, 20 MW) and later sale of that unit when the greenfield projects are completed (Atlin, BESS, Moon Lake). What is the impact of these options on GHG emissions?

c) Disclose all documents within YEC's control, both public and internal, relating to the comparative benefits and disadvantages of thermal generation options, including rental diesel generators, purchasing portable diesel generators, and constructing a large (e.g. 20 MW) permanent diesel generator. Include all comparative financial benefits and disadvantages of each option.

d) Referring to the final paragraph of 4.2, how many "stakeholders" were opposed to the permanent generator option and what specific interests did these stakeholders represent? Were these stakeholders full informed of the other options – e.g. continuing use of rental diesel generators? Were the stakeholders informed about the comparative electrical rate impacts associated with the available options?

ANSWER:

(a)

YEC did not undertake any new analysis regarding the diesel rental option. Dependable capacity for thermal generation was benchmarked against other permanent generation options (i.e., new greenfield diesel) and not against a rented diesel option. As reviewed in section 4.1.1 of YEC's Submission (page 19), the Board in its BESS Report was "…persuaded that only relying on rented diesel generators would be challenging and would not be a reliable way of closing the capacity shortfall gap."[1]

(b) and (c)

Yukon Energy reviewed in the 2021 GRA proceeding (as well as in the prior BESS Project Part 3 Application proceeding) its earlier investigations of thermal generation options (permanent and rental diesels). YEC has not carried out any new investigations, given its need to focus on implementing the 10-Year Renewable Electricity Plan, including the BESS Project, replacement of retired diesel generation, the Atlin EPA, and seeking funding needed to carry out planning for the Tutshi-Moon Lake Pumped Storage Project and the new transmission connection of Whitehorse-Skagway to enable sale of surplus summer YEC renewable energy to displace cruise ship diesel generation. Major new permanent diesel options (beyond replacement of retired units) are only likely to be revisited within the next decade in the event that the Tutshi-Moon Lake Pumped Storage Project (or some equivalent renewable option) is confirmed not to be feasible at this time.

A summary of the relevant record based mainly on the 2021 GRA proceeding is provided below in response to these questions.

Rented Diesels as Feasible Option for Near-Term Capacity Shortfall

YEC has conducted several detailed assessments of more permanent options for addressing the dependable capacity shortfall since diesel rentals were first installed for the 2017/18 winter – including YEC's recent 10 Year Renewable Electricity Plan completed in 2020 and its earlier more detailed assessment of a 20 MW new diesel plant and other options in YEC's 2016 Resource Plan.

[1] YUB Report to the Yukon Minister of Justice - YEC Application for Energy Project Certificate and Energy Operation Certificate Regarding the Proposed Energy Battery Storage System (BESS) Project, June 30, 2021, page 11. A copy of this report is provided at YUB-YEC-1-32, Attachment 2.

In summary, the evidence confirms that Yukon Energy has diligently assessed permanent options to address the capacity shortfall:[2]

- YEC's 2016 Resource Plan issued in spring of 2017 was the first time the magnitude of the current dependable capacity shortfall was identified as a major issue; the 2016 Resource Plan reviewed extensively the possible permanent options. As a result of that extensive review the Plan recommended a number of possible permanent options including a new 20 MW diesel plant (with provision for future expansion to 30 MW), a BESS project, a third LNG unit, dependable capacity DSM, and potential new dependable hydro capacity options.

- YEC first rented diesels for the following winter of 2017/18. It was without question the only feasible option for that winter to address the then identified N-1 dependable capacity shortfall. YEC has continued to pursue diesel rental thereafter as required each winter to address the forecast N-1 dependable capacity shortfall until permanent solutions can be brought into service. In this context, rented diesels have become the default option used to assess the cost effectiveness of proposed permanent solution options such as the BESS project and permanent diesel replacement options.

- Following the 2016 Resource Plan, YEC diligently pursued permanent solution options, including the 20 MW new diesel plant, the third LNG unit, the BESS project, dependable capacity DSM, and potential new dependable hydro capacity options. Given these actions there is no basis for suggesting that YEC was imprudent or irresponsible in its planning to address the dependable capacity gap.

- As a result of detailed planning assessments (including consultation and engagement on the 20 MW new diesel plant site options), YEC's Board in 2019 rejected that alternative for further consideration and directed that new permanent thermal options focus on diesel replacement at existing plants.

- Yukon Energy is currently diligently acting to implement the 10 Year Renewable Electricity Plan that includes diesel replacement options at existing diesel plants, renewable capacity alternatives including BESS, dependable capacity DSM, and

[2] See Mr. Hall, 2021 GRA Transcript pages 450 to 454; 2021 GRA CW-YEC-2-6(a) and (b).

dependable hydro capacity provided by the Atlin Hydro Expansion project and the Tutshi-Moon Lake Pumped Storage project.[3]

- Yukon Energy has confirmed that as at 2019, when the decision was made to not pursue the 20 MW new diesel plant option after completion of detailed planning work, it would have taken at least four years to plan, permit and construct a new 20 MW or 12.5 MW diesel plant, i.e., such a new diesel plant could only have been available in 2023 at the earliest.[4] In other words that option -- even if it was pursued -- could not have been in service during the 2021 test year.

In summary, the evidence confirms that rented diesels are the only feasible option for Yukon Energy to address the dependable capacity gap for the 2021 GRA test year and other near-term periods. Further, the evidence confirms that this situation exists notwithstanding YEC's ongoing diligent pursuit of new permanent solution options to address the dependable capacity gap.

Further, the evidence also clearly demonstrates the challenges that Yukon Energy faced in successfully securing sufficient additional rental diesels (including moving to place sufficient units at Faro) by winter 2020/21 following the lessons learned from the extended cold spell in January 2020.[5]

Renting for the long-term, however, is not a preferred option. As noted in response to "a", renting as a long-term option would be challenging and not a reliable option – it would also likely be more costly than a permanent diesel option.

Renting Option is Preferable to Possible Ownership that assumes subsequent Sale

[3] 2021 GRA CW-YEC-2-6(a) and (b). These investigations were detailed in the response, with reference to 2021 GRA CW-YEC-1-36(a) Attachment 1 copy of the YEC 10-Year Renewable Electricity Plan completed during 2020. Ms. Milojevic also reviewed the extensive work done by YEC to identify and cost options for the 2016 Resource Plan and the current 10-Year Renewable Electricity Plan, 2021 GRA Transcript pages 458-460.
[4] Mr. Hall, Ms. Milojevic, 2021 GRA Transcript pages 454-456.
[5] Mr. Gazankas, 2021 GRA Transcript pages 445-446.

Questions were raised in the 2021 GRA Exhibit C-6 and in 2021 GRA cross examination by the Board[6] relating to the possibility of purchasing rather than renting required diesel units, with an assumed later sale when greenfield projects are completed.

YEC has provided business case Levelized Cost of Capacity (LCOC) cost comparisons for new permanent dependable capacity project options (including permanent YEC owned diesels) versus rented diesels. These LCOC cost assessments confirm that diesel rental costs are reasonable in comparison with permanent diesel costs when these can be installed.[7]

Further, the evidence also demonstrates that rented diesels is a flexible year-by-year option that avoids capital cost commitments and related risks associated with asset ownership options. As such the LCOC comparison is directed at simply confirming the cost effectiveness of permanent solutions (when these are feasible to implement) relative to the rented diesel option, i.e., the LCOC assessment alone is not a useful indicator for assessing rented diesel costs for the 2021 test year.

As evidenced by the 10-Year Renewable Electricity Plan, YEC is actively pursuing a range of permanent dependable capacity options to remove the need for reliance on rented diesels as soon as this can reasonably be achieved within an effective long-term resource development plan – but as noted none of these options can displace the need for rented diesels in the 2021 GRA test year as well as other near-term periods.

Focusing then only on rented diesels, YEC has confirmed that purchase rather than rental of these units is not a prudent or practical option for the Corporation even when subsequent sale of the units is considered as a way to retain a degree of flexibility relative to “permanent ownership” options:

First, the current rental units are not the type of unit that YEC would ever seek to secure as permanent units. Further, and in any event – Finning (who is renting the units to YEC)

[6] Mr. Fortin, 2021 GRA Transcript pages 430-433.

[7] 2021 GRA CW-YEC-2-6(a) and (b). Diesel rental costs are indicated at $162.4/kW for winter 2021/22 for 27 MW (15 units for N-1 requirements), versus an LCOC (2022$) of $211/kW for 20 year life and $243/kW for a 40 year life. A 12.5MW YEC owned diesel plant option LCOC (2022$) with a 40 year life is estimated at $186/kW without property tax (Takhini site) and $212/kW with property tax (Whitehorse site).

has not made any proposals for YEC ownership and in some cases does not even own the units that it is renting to YEC.[8]

Second, Mr. Hall reviewed in the 2021 GRA proceeding in some detail why a purchase/sale alternative would not be a realistic or practical option that YEC could quantify adequately at the front end. He explained why he would not be comfortable getting into the business of trading diesel units pretty much on an annual basis, and why renting diesel units is an appropriate way to address relevant ongoing uncertainties as to the need for additional diesel units.[9]

> Briefly, I don't believe it's a realistic option that we would have been able to quantify economically in an adequate fashion at the front….
>
> Well, you can imagine that, you know, a strategy to rent, the rental costs are known at the front end. If we were to look at an option to purchase and then sell again in the future, we have to look at, firstly, you know, what certainty we have around those overall economics. Then the practicality of buying and selling units potentially on an annual basis.
>
> So I'll deal with each of those in turn.
>
> So the first thing about cost certainty, I know of no way that we could have confirmed the sale price of the units four, five, eight years down the track to an adequate level of certainty that our board would have been comfortable that we had a handle on the economics. So that's the first point. In terms of practicality, you know, I'll draw folks attention to Figure 20 again in the 10-year renewable plan….
>
> So you can see that the height of the hatched grey bars, the temporary diesel rental, varies over time. So you can see as additional resources are brought online through to 2024, so that would be the battery for example, plus the Atlin project, the number of rentals would drop. So we would be

[8] Mr. Mollard and Mr. Hall, 2021 GRA Transcript pages 305-306; Mr. Mollard, 2021 GRA Transcript page 431. Also Mr. Hall and Mr. Mollard, 2021 GRA Transcript pages 432-433 (Mr. Mollard also references here looking continuously for potential other rental suppliers than only Finning, who to date was the least cost rental supplier offering this service to YEC).
[9] Mr. Hall, 2021 GRA Transcript, pages 461-463.

> buying diesels, then selling them and then lo and behold after 2024 the height of that bar starts growing again. So we'd have to be buying again.
>
> So this whole idea of getting into the business of trading pretty much on an annual basis diesel engines, I mean, that's not our business, and I wouldn't be comfortable with us getting into that line of work.
>
> So given that profile of how many rentals we need, I think the idea -- renting gives you a lot more flexibility in terms of being able to determine the number of rentals on an annual basis and not having to buy and sell and trade those units.
>
> Also, as we've seen, there's some uncertainty to all of this, of course. So how quickly load grows, it has some uncertainty associated with it. And renting is an appropriate way of accommodating that uncertainty. If we were buying, we would be locking ourselves in, and then having to respond in a much more inflexible way to changes in circumstance.
>
> So I think if I look at those two factors together, the idea of buying rental units and then selling them again we just viewed as not being a practical solution for the company.

In summary, the evidence confirms that a potential diesel ownership option premised on subsequent resale when greenfield options are developed is not an acceptable option for YEC.

(d)

Yukon Energy has previously provided its results from the engagement process for the 20 MW new diesel plant option. Attention was directed at the specific options then under review. The summary in the referenced quote reflected the overall outcome.

The full report on the engagement process on the new greenfield 20 MW diesel plant project is attached (see YUB-YEC-1-36(d) – Attachment 1). The report highlights strong interest in ensuring that renewable options are fully explored and that permanent thermal generation options are minimized to the extent possible.

ISSUE: **EPA constraints**

REFERENCE: **Application, page 25, PDF page 28**

QUOTE: "The effect on customer rates of energy and capacity purchases under the EPA is constrained by the agreed price and payment terms (see Section 2.4.3 of this Submission) and the actual dependable capacity and delivered energy provided by THELP."

QUESTION:

a) Please explain the above quote and why the statement is accurate in terms of the effect on customer rates.

ANSWER:

(a)

The above quote incorrectly references Section 2.4.3 of the Submission (which does not exist) – the relevant reference is Section 3.4.2 of the Submission (see also response to YUB-YEC-1-40).

The referenced quote from Section 4.2 is an introduction to review of EPA effects on customer rates. In summary, the quote states that effects on customer rates from YEC's Atlin EPA purchases (of energy and capacity) is determined by two main factors:

- The EPA price and payment terms (which are summarized in Section 3.4.2 of the Submission); and

- The actual volumes of dependable capacity and delivered energy provided by THELP.

The statement accurately summarizes the factors determining EPA annual total impacts on YEC's costs. Further, review of EPA price and payment terms highlight that these have been determined based on forecast YEC costs for thermal generation options that are assumed (for EPA pricing) to be otherwise required, i.e., the net cost impact on customer rates is mainly determined by the EPA price and payment terms to the extent that costs with the EPA are basically the same as (and in some situations lower than) would otherwise occur without the EPA.

The subsequent text in Section 4.2 after the referenced quote addresses in more detail the price and payment provisions for Dependable Capacity, Winter Delivered Energy, and Summer Delivered Energy and the likely EPA net impacts on customer rates. This text highlights the importance of the EPA commercial terms and factors that may impact final net impacts on customer rates. In addition, a third factor is in effect identified as affecting net customer rate impacts, i.e., the actual (vs the forecasts used to set EPA prices) thermal fuel costs and grid conditions regarding loads and other renewable resources.

ISSUE: **Costs for dependable capacity**

REFERENCE: **Application, page 25, PDF page 28**

QUOTE: “EPA impacts on YEC costs for dependable capacity and delivered energy are designed to mirror or improve upon the cost impacts on YEC and customer rates forecast for a permanent thermal generation option”

QUESTION:

a) Why is a permanent thermal generation option the standard by which these costs (Dependable Capacity Payment and Winter Delivered Energy) are measured?

b) Should not the costs for dependable capacity be measured under the EPA on whether those costs are less than a thermal generation option? If no, why not?

ANSWER:

(a)

The permanent thermal option was adopted as the benchmark for costs on the assumption:

(a) That thermal generation in general is the least cost option for both dependable capacity and winter energy (for energy, this enables reference to the blend of LNG and diesel thermal generation); and

(b) That permanent thermal (diesel) is the preferred thermal long-term option (compared to diesel rentals) given the challenges and reliability risks of adopting rented diesels on an ongoing basis for the next several decades.

Please also see response to YUB-YEC-1-7(a), which also highlights the focus on selecting renewable generation options.

(b)

No. As reviewed in the response to YUB-YEC-1-7(a), the clear public policy need is to develop where feasible the renewable generation options. Accordingly, renewable options such as the Atlin EPA are very attractive if they are simply cost competitive with thermal generation options. Under the Atlin EPA, YEC therefore sought a renewable option that was cost competitive with permanent thermal. Under the EPA, under some circumstances the EPA will also be less costly than thermal generation.

ISSUE: **Dependable Capacity Payment**

REFERENCE: **Application, page 25, PDF page 28**

QUOTE: "Dependable Capacity Payment (DCP): the DCP payment to THELP by YEC in the EPA is based only on the Dependable Plant Capacity Committed (DPCC) as confirmed by an annual December test as provided for in Section 5.5 of the EPA, and a Dependable Capacity Price of $200/kW per year (2024$) as escalated at CPI after 2024.

This price and cost to YEC reflects the levelized capacity and non-fuel O&M costs to YEC as estimated for equivalent permanent new diesel generation capacity."

QUESTION:

a) Explain why a largely fixed cost needed to be escalated by CPI?

b) Why is $200/kW the standard and why is $175/kW not the standard for the Takhini greenfield plant?

ANSWER:

(a)

Please see response to YUB-YEC-1-27. The LCOC used as the benchmark levelized the fixed cost component to set a year 1 price that will reflect YEC weighted average cost of capital over the 40 year diesel plant life. This levelized price also assumed annual escalation at CPI.

(b)

Please see response to YUB-YEC-1-13(a) which notes as follows regarding the cost for greenfield new diesel generation capital and non-fuel O&M at (2024$) $200/kW-yr:

> This price is within the bottom end of the range for levelized cost of capacity (LCOC) estimates of YEC levelized cost of capacity (i.e., fixed capital and O&M costs, excluding fuel costs) for a 12.5 MW new diesel generation facility of $175

per kW (2019$) if located at Takhini without any property taxes, and $199.8 per kW (2019$) if located in Whitehorse with related property tax costs (see response to Undertaking #7 in BESS proceeding). The 2019 LCOC costs escalated at 2% per year for inflation to 2024 equal $193 and $220.6 per kW respectively.

ISSUE: **Unknown reference**

REFERENCE: **Application, page 25, PDF page 28**

QUOTE: "The effect on customer rates of energy and capacity purchases under the EPA is constrained by the agreed price and payment terms (see Section 2.4.3 of this Submission) and the actual dependable capacity and delivered energy provided by THELP."

QUESTION:

a) The application outline does not show a "Section 2.4.3". Please provide the correct reference and explain the meaning of the above paragraph.

ANSWER:

(a)

The correct reference should be to section 3.4 of the Submission which reviews the commercial terms of the EPA. Section 3.4.1 reviews key principals and section 3.4.2 provides a summary of EPA commercial terms relevant to the referenced quote from the Submission.

ISSUE: **Summer delivered energy**

REFERENCE: **Application, page 26, PDF page 29**

QUOTE: "Summer Delivered Energy (June-August) - summer energy deliveries, if requested by YEC, will be paid based on a Summer Delivered Energy Payment as provided in the EPA. This payment is equal to Summer Delivered Energy times 50% of the then current YUB approved blended fuel thermal price for YEC generation on the YIS."

QUESTION:

a) Is the price based on the last Board-approved GRA blended fuel thermal price, or is it based on the last approved GRA price plus any subsequent Rider F changes? Please explain.

ANSWER:

(a)

The summer energy price is based on the last Board-approved GRA blended fuel thermal price. The approach is the same as adopted in section 3(2) of OIC 2019/25 for setting the price for an IPP under an on-grid electricity purchase agreement. The intent is to reflect the latest Board-approved GRA blended fuel thermal price without the added complexities of addressing subsequent Rider F changes made by the utilities without the need for Board approval.

ISSUE: **Accounting treatment of EPA**

REFERENCE: **Application, page 26, PDF page 29**

QUOTE: "There is some uncertainty with respect to what, if any impact the EPA may have on YECs balance sheet (i.e., rate base). Based on preliminary assessments of the Agreement, YEC has concluded that this transaction does not contain a capital lease and therefore there is no balance sheet or rate base impact. This conclusion, however, is not final. The ultimate impact can only be known when the Project is complete and YECs auditors (the Auditor General of Canada) have reviewed the transaction."

QUESTION:

a) Provide the basis of the preliminary assessments of the agreement that led to YEC's conclusion.

b) If it is determined that the agreement operates as a capital lease, what are the impacts to the agreement and to customer rates?

c) Please explain why YEC has not sought an external opinion on the accounting treatment of the EPA.

ANSWER:

(a)

YEC assessed the accounting for this agreement through a review of applicable sections of International Financial Reporting Standards (IFRS) which applies to YEC as a Government Business Enterprise.

The question of whether the EPA will result in a long-term asset and liability on the balance sheet depends principally upon the following determinations:

- Whether either of the two situations that could result in the asset and liability being on balance sheet are applicable:

  - Control and therefore consolidation of the counterparty; and
  - Whether the arrangement is a lease or contains lease components under International Financial Reporting Standards ("IFRS").

- In the event the arrangement is a lease, whether any portion of the payments under the agreement are fixed or in-substance fixed lease payments required to be recorded as liabilities with a corresponding right-of-use asset.

Our preliminary accounting assessments under IFRS are as follows:

YEC does not have control, as defined in IFRS 10 *Consolidated financial statements*, or joint control, as defined in IFRS 11 *Joint arrangements*, over the counterparty to the arrangement, THELP. Specifically, YEC does not have the current ability to direct the activities of THELP that significantly affect THELP's returns, either unilaterally or shared with another party. YEC does not believe this determination to be highly subjective although it will not be subject to discussion with YEC's auditors until the agreement has been consummated.

Further, the agreement is not a lease in its entirety under IFRS because certain of the principal assets (notably, the Surprise Lake storage and control structure) support not only fulfilment of the contract with YEC but also the generation of power for third parties (i.e., Atlin, BC). YEC has concluded the utility does not control the use of such assets, as supported by the fact that YEC does not meet the criteria outlined in IFRS 16.B9, in particular:

  - YEC does not have the right to substantially secure all the economic benefits of these assets because they are used for the benefit of both YEC and a third party; and
  - YEC does not have the right to direct the use of such assets (which are subject to pre-existing agreements between parties that have no relationship with YEC).

There is significant judgment on the determination of whether the agreement otherwise contains lease components with respect to other assets owned by THELP and dedicated to the delivery of capacity and energy to YEC (such as the Upper and Lower Powerhouses, the power canal, penstock and transmission lines). The subjectivity arises because of the degree to which the use of the physical assets is interconnected, many activities are subject to predetermined protocols mutually agreed by the parties under the EPA, and the degree to which each party has responsibility for certain decisions during different seasons throughout the term of the EPA.

In light the of the acknowledged complexity and judgment involved in these determinations, YEC considered whether any portion of the future payments would be recorded on YEC's balance sheet in the event any of these assets were determined to be leases. The principal provisions of IFRS 16 *Leases* that affect whether any portion of the payments constitutes a lease liability (resulting in a corresponding right-of-use asset, both recorded on YEC's balance sheet) are the extent to which the payments are:

a) Fixed payments (including in-substance fixed payments), in which case such payments constitute lease liabilities recorded on balance sheet at their present value; or

b) Variable payments (including payments which are dependent on the future performance or use of the underlying assets), in which case such payments do not constitute lease liabilities. IFRS 16.BC169 indicates that such payments could be viewed as a means by which the lessee and lessor can share future economic benefits to be derived from the use of the asset.

YEC identified that only the dependable capacity payments required more detailed scrutiny in considering whether any portion of the payments would constitute lease liabilities under IFRS 16, as all other payments under the agreement vary based on the electricity delivered, with no specified contractual minimum amounts.

The dependable capacity payments under the lease are determined annually as a result of a 24-hour performance test to be conducted in December, which measures the total energy delivered over the 24-hour test period. The results of this test are expected to vary year-to-year based on the amount of dependable capacity THELP can demonstrate the plant can deliver at the beginning of each winter season. Following the test, the minimum capacity payments for the ensuing winter period become fixed. However, as of the date of commencement of the lease, which is the date the plant becomes operational and able to generate electricity for YEC's benefit, the amount of these payments is undetermined and dependent on the future performance of the asset.

Pursuant to IFRS 16 and after consulting published guidance from the Big 4 accounting firms under both IFRS, and the same provisions in US GAAP, YEC has concluded that as expressly documented in published sources, even variable payments that are highly certain to occur do not result in lease liabilities if the payments are based on the performance or usage of the underlying asset, such as in the case of the dependable capacity payments described above.

On this basis YEC has preliminarily concluded that, subject to future concurrence with YEC's auditor, energy and capacity payments will not be recorded on YEC's balance sheet under IFRS prior to the year to which they relate.

(b)

Unless the YUB directs an exception from GAAP, a lease asset (right-of-use asset under IFRS 16) would be included as part of rate base and the utility would be entitled to charge ratepayers a return on that asset. Such treatment would have a direct impact to ratepayers. As evidenced in this Submission, YEC has carefully analyzed the impact of this agreement versus lowest cost alternatives. Should YEC auditors determine that recording an asset is necessary, YEC will investigate options for ratemaking purposes to ensure the financial advantages of this agreement are not diluted by this accounting treatment.

(c)

YEC consulted a major accounting firm to advise it on this analysis. To YEC's knowledge, accounting firms will not provide an opinion on accounting outside of a formal audit process. YEC believes that, based on the terms of the agreement and the known industry practice, it is reasonable to conclude that there is no balance sheet impact. However, YEC was also advised that the nature of the accounting determinations involve subjectivity and therefore a final determination will only be possible when an audit is performed after the project is in service.

ISSUE: **YEC costs**

REFERENCE: **Application, page 27, PDF page 30**

QUOTE: "The EPA also provides for any YEC costs for studies and other works to be fully funded by the Project (i.e., by THELP and not by the utilities) with advance payments as required – the only costs not funded by THELP relate to YEC's EPA negotiation costs and costs related to this Submission to the YUB."

QUESTION:

a) Provide examples of what types of studies may be required and any estimates of costs to customers for further studies.

b) Provide an itemized breakdown of YEC's costs associated with the EPA planning, analysis, consultations, etc.

ANSWER:

(a)

The studies referenced in the quote are those required for the Buyer-AEY System Interconnection Report, including evaluation of the impact of Seller's Plant on the reliability of Buyer-AEY System, the scope of required Buyer-AEY System Upgrades to address these impacts, and planning-level estimates of required Buyer-AEY System Upgrade Costs. No costs to customers are estimated to be required for further studies.

(b)

The table below captures the costs incurred by YEC to date related to planning, analysis and negotiations for this EPA.

Expense Type	
Legal	507,949
Consultants	311,056
Contractors	172,830
Internal Labour	18,867
AFUDC	10,150
Travel & Miscelaneous	5,311
	1,026,163

Contractor costs relate to system impact and operational studies that YEC expects to recover from the seller. The remaining costs are related to EPA negotiations and are expected to be recovered through rates.

These costs will increase as YEC will incur costs as part of finalization of Conditions Precedent under the EPA. YEC estimates approximately $0.175 million will be recoverable from THELP, subject to final reconciliation and invoicing. YEC is separately tracking the costs of this proceeding and will apply for recovery in accordance with YUB rules.

ISSUE: **EPA prices and energy deliveries**

REFERENCE: **Application, page 28, PDF page 31**

QUOTE: "The EPA prices are sensitive to firm energy versus non-firm energy deliveries over the year – a factor which will tend to reduce cost impacts for YEC from variances in actual versus LTA costs related to EPA energy deliveries."

QUESTION:

a) Please provide further explanation on EPA prices and sensitivity because of deliveries.

b) How would the factor work?

ANSWER:

(a) and (b)

Energy price payments for Winter Period energy deliveries per section 8.2 of the EPA include two amounts (see also Table 3-1 of the Submission):

1. The Firm Winter Energy Price is paid for the first 25.2 GWh of Delivered Energy and Monthly Constraint Energy during the Winter Period of a calendar year; and

2. The Non-Firm Winter Energy Price is paid for Delivered Energy and Monthly Constraint Energy in excess of 25.2 GWh during the Winter Period of a calendar year.

As summarized in Table 3-1 of the Submission, these prices in the EPA are in 2024$ with one set of firm and non-firm prices for 2024-2034 and another set of prices for 2035 and the balance of the EPA term. The firm energy price is higher than the non-firm energy price throughout the EPA term. These prices all escalate after 2024 at 50% of CPI.

Tables A3-1 and A3-2 of the Submission review the calculations and assumptions for determining these firm and non-firm energy prices. Further explanation is provided in YUB-YEC-1-11 and YUB-YEC-1-12.

ISSUE: **Clean Energy Act**

REFERENCE: **Application, page 28, PDF page 31**

QUOTE: "Shortages in LTA Project energy deliveries relative to the LTA forecasts in this Submission could prevent YEC from meeting the 93% Renewable Portfolio Standard in the expected new Clean Energy Act. The YEC financial/ratepayer impact of such a shortfall is unknown at this time, e.g., it could potentially result in fines."

QUESTION:

a) Please explain why YEC would expect potential fines for violations of the Clean Energy Act.

b) Would any potential fines be considered a shareholder expense rather than a ratepayer expense? Would YEC attempt to have such fine payments added to its rate base?

ANSWER:

(a) and (b)

While the exact terms of this Act are not known today, YEC believes it is normal practice for legislation of this nature to include penalties against individuals or entities who fail to comply with the Act's terms. The referenced quote states that the YEC financial/ratepayer impact of such a shortfall is unknown at this time. The example of potential fines is simply noting the possibility of a financial penalty – it is not suggesting that YEC expects this specific possibility. YEC has no assessment at this time as to how such potential fines would be considered with regard to rates. There is, however, the possibility that such costs might be added to rates.

ISSUE: **No industrial load**

REFERENCE: **Application, page 29, PDF page 32**

QUOTE: "However, over most of the EPA Term (i.e., from 2035 through to July 31, 2064) the EPA prices assume no industrial load – thereby minimizing risks to YEC and to customer rates."

QUESTION:

a) In the scenario of no industrial load post-2034, would EPA purchases displace YEC hydro generation for the YIS system? Please explain why or why not.

ANSWER:

(a)

Yes, under the assumed scenario of no industrial load post-2034 a material portion of EPA purchases (but not all of these purchases) would displace YEC hydro generation on the YIS. The winter energy prices in the EPA for the post-2034 have been reduced to reflect the reduced expected thermal displacement benefits based on this scenario – with provision for Additional Payment if there is Added Load above this scenario's forecast (see Table 3-1 of the Submission for a summary of the relevant energy prices).

See the response to YUB-YEC-1-11 and YUB-YEC-1-12 for a more detailed review of how the EPA energy price determinations reflect the extent of expected YIS thermal generation displacement versus YEC hydro generation displacement.

ISSUE: **Costs arising from the Implementation Agreement**

REFERENCE: **Application, page 29, PDF page 32**

QUOTE: "YEC will seek to recover from AEY, through the Implementation Agreement, any such costs due to a Non-Permitted System Constraint on the AEY System."

QUESTION:

a) Explain the Implementation Agreement and how cost recovery under the agreement would operate.

ANSWER:

(a)

Under the Atlin EPA (as is also case for SOP EPAs for the YIS), YEC as Buyer is the party responsible to Seller for purchases, as well as for various other activities, including completion of System Upgrades, operation of the YIS, and any payments required to Seller as a result of a Non-Permitted System Constraint on the YIS. The YIS affected by the Atlin EPA includes the AEY System as well as the system owned and operated by YEC.

Section 2.1(d)(ix) of the Atlin EPA provides a Condition Precedent requiring YEC to have entered into an implementation agreement with AEY for the implementation of this EPA on terms and conditions satisfactory to YEC, acting reasonably. The purpose of the implementation agreement is to address all of the necessary arrangements required between YEC and AEY in order for YEC to implement the EPA. The EPA has been amended to extend the date to March 31, 2022 for completing this requirement. This agreement is still being finalized by the parties. Similar implementation agreement requirements have been finalized for the SOP EPAs.

A Non-Permitted System Constraint can result in a requirement for payments to be made by YEC to THELP for energy that THELP could not deliver due to the System Constraint. See YUB-YEC-1-25 for a more detailed review of these provisions.

The YEC-AEY implementation agreement for the Atlin EPA will provide for mechanisms to track any System Constraint, its location on the AEY System versus the YEC system, the apparent cause of the System Constraint and its impact on Seller energy deliveries. In cases where a Non-Permitted System Constraint requires YEC to pay THELP for Monthly Constraint Energy, the YEC-AEY implementation agreement will provide for YEC to seek recovery from AEY for any such costs due to a Non-Permitted System Constraint on the AEY System. The details for this provision are yet to be finalized for this agreement.

ISSUE: **Water Storage Savings**

REFERENCE: **Application, Appendix A, Figure A1-1, page A-5, PDF page 40**

QUOTE:

QUESTION:

a) Figure A1-1 shows Water Storage Savings of 2.8 GWh/yr. Explain what this value relates to and how that amount was determined.

ANSWER:

(a)

Water Storage Savings represents the value of thermal displacement avoided due to EPA deliveries enabling added hydro storage on the YIS. It is distinguished from thermal displacement that occurs directly due to EPA deliveries. As shown in Figure A1-1, total LTA thermal displacement of 19.6 GWh/year is the total resulting from direct thermal displacement (16.7 GWh) and water storage savings thermal displacement (2.8 GWh).

As noted in Table A1-1, LTA thermal displacement has been estimated based on YECSIM model simulation runs for 38 water years. Key assumptions are noted in this table.

ISSUE: **Conditions Precedent**

REFERENCE: **Application, Appendix B, page B-5, PDF page 49**

QUOTE: TRTFN Approval: Section 2.1(d)(vi) of the EPA Conditions Precedent specifies that, on or before May 31, 2022, Seller will have obtained approval of the EPA by the TRTFN by way of Clan Directive or a Joint Clan Meeting Mandate.

QUESTION:

a) Prior to the negotiation of the EPA, did YEC engage in any consultations with TRTFN or other persons/parties who would be impacted by TRTFN approval as a condition precedent?

b) Please describe the engagements involving TRTFN.

c) Over what time period did this stakeholder engagement occur?

d) Please explain the difference in TRTFN approval between Clan Directive and a Joint Clan Meeting Mandate.

e) Who would have to vote for TRTFN approval? What happens if TRTFN approval is denied or does not occur by May 31, 2022?

f) What stakeholder engagement occurred for transmission line construction between the Yukon/BC border and Jakes Corner?

g) Which parties were involved in the consultation process?

h) What project approvals are required from First Nations for any project construction in Yukon in general, and are there any other approvals required that are specific to this project?

i) If there has been First Nation consultation, has any accommodation of First Nation interests been required or made, and if so, what costs have been or will be incurred by YEC in that regard?

ANSWER:

(a)to (c), (f),(g) (i)

Prior to negotiating the EPA, Yukon Energy did not engage in consultations specific to the Atlin Project.

The Atlin Project is being developed by THELP, and THELP is therefore the party responsible for all related First Nation engagement and consultation. Yukon Energy does not have details regarding how THELP has carried out these responsibilities. Yukon Energy has also not conducted any engagement or consultation with TRTFN or other First Nations with regard to this project, and does not expect to incur any costs in this regard or any costs for accommodation of First Nation interests with regard to this project.

THELP consultation and engagement on the Project transmission development from the Yukon/BC border and Jakes Corner were provided as required in its Project Proposal submission to YESAB, and addressed as required by YESAB prior to issuing its September 10, 2021 Evaluation Report recommending that this component of the Project proceed.

(d) and (e)

Yukon Energy is not aware of the specific differences in TRTFN approval between a Clan Directive and a Joint Clan Meeting Mandate, or who specifically would have to vote for either such approval. The requirements in this instance derive from THELP needing the approval of its owners. The referenced condition precedent requires that one of these approvals be secured by TRTFN on or before May 31, 2022.

If the required approval is denied or does not occur by May 31, 2022, the EPA cannot proceed to come into force and the Project cannot proceed unless the specified condition precedent date is extended or waived by agreement of YEC and THELP.

(h)

In general, First Nation approvals are required in Yukon for project activities on Settlement Land. Such approvals were required, for example, from two First Nations for development of the Carmacks-Stewart Transmission Project that required facilities to be located on certain Settlement Lands. No such approvals are required for the Atlin Project.

ISSUE: **Thermal generation displacements**

REFERENCE: **Application, Appendix B, footnote 14, page B-10, PDF page 54**

QUOTE: "Thermal generation reductions vary depending on Yukon Integrated System (YIS) water conditions. The LTA estimates are derived based on simulation assessments for 38 different YIS water years, taking into account direct thermal displacements by Atlin energy and also indirect thermal displacements by Atlin energy through facilitating enhanced hydro storage on the YIS that enables increased winter hydro generation in some of the water years. Estimates are derived from YECSIM model LTA assessments without and with Atlin energy deliveries, based on forecast YIS firm generation load requirements in 2024 and 2035 and planned YIS capability without the Project (including expected water use licence conditions, YEC hydro plant uprates and other expected IPP generation purchases by YEC). See Appendix A, Table A3-1 for 2024 and 2035 LTA thermal estimates (and related assumptions) with and without the Project."

QUESTION:

a) Please explain the term "indirect thermal displacements".

b) Does the quote above mean that YEC will use energy from the EPA and withhold YEC hydro generation?

ANSWER:

(a) and (b)

"Indirect thermal displacements" occur where certain EPA deliveries allow YEC to curtail hydro generation and thereby increase hydro reservoir levels. This additional storage can then be used in the future to secure added thermal displacement.

Please see YUB-YEC-1-48 for additional information on this thermal displacement and how it differs from “direct thermal displacement”, as well as estimates for each as provided in YEC’s Submission.

ISSUE: **Firm Winter Energy Price**

REFERENCE: **Application, Appendix B, footnote 15, page B-10, PDF page 54**

QUOTE: "Section 8.2 of the EPA provides for monthly payment of the Firm Winter Energy Price (for estimated low flow water year winter delivery levels) and the Non-Firm Winter Energy Price (balance of winter deliveries) for Delivered Energy and Monthly Constraint Energy during the Winter Period."

QUESTION:

a) Please provide the basis for the statement in the above-quoted footnote.

b) Please explain the difference between "firm winter energy" and "non-firm winter energy".

c) Is all pricing based on assumed low-flow water years? Please explain why or why not.

ANSWER:

(a)and (b)

Energy price payments for Winter Period energy deliveries per section 8.2 of the EPA include two amounts (see also Table 3-1 of the Submission):

1. The Firm Winter Energy Price is paid for the first 25.2 GWh of Delivered Energy and Monthly Constraint Energy during the Winter Period of a calendar year; and

2. The Non-Firm Winter Energy Price is paid for Delivered Energy and Monthly Constraint Energy in excess of 25.2 GWh during the Winter Period of a calendar year.

As summarized in Table 3-1 of the Submission, these prices in the EPA are in 2024$ with one set of firm and non-firm prices for 2024-2034 and another set of prices for 2035 and the balance of the EPA term. The firm energy price is higher than the non-firm energy price throughout the EPA term. These prices all escalate after 2024 at 50% of CPI.

(c)

All pricing is not based on assumed low flow water years at Atlin. The EPA pricing overall reflects LTA water availability at Atlin. Only the firm energy price is based on the low flow year. The non-firm energy price reflects the balance of thermal displacement from LTA flows in excess of the low flow year.

Tables A3-1 and A3-2 of the Submission review the calculations and assumptions for determining these firm and non-firm energy prices. Further explanation is provided in YUB-YEC-1-11 and YUB-YEC-1-12.

ISSUE: **Delivered Energy**

REFERENCE: **Application, Appendix B, page B-12, PDF page 56**

QUOTE: "First 25.2 GWh/year of Delivered Energy and Monthly Constraint Energy – Firm Winter Energy Price of $0.132/kWh for 2024, increased by 50% of CPI for each Year after 2024 until completion of 2034."

QUESTION:

a) Please explain the difference between "Delivered Energy" and "Monthly Constraint Energy".

ANSWER:

(a)

Per section 1.45 of the EPA, Delivered Energy is the amount of Energy delivered in KWh by Seller to Buyer at the POI in that month as recorded by the Meter. If a Party disputes the accuracy of the Meter, the amount of Delivered Energy is as determined under Section 3.8.

Monthly Constraint Energy is defined in Schedule "F" of the EPA and relates to circumstances where there has been a Non-Permitted System Constraint. In summary, Monthly Constraint Energy requires YEC payment for winter energy that THELP could not deliver due to a Non-Permitted System Constraint. Please see YUB-YEC-1-25 for a more detailed explanation of Monthly Constraint Energy and how it is determined.

ISSUE: **Estimated thermal displacements**

REFERENCE: **Application, Appendix B, page B-12, PDF page 56**

QUOTE: "If Carbon Charge included in YUB approved YEC rates, pay 50% of carbon tax per kWh times estimated thermal displacement during these winters (estimated at 63.5% of all winter deliveries in these years)."

QUESTION:

a) Please explain how the 63.5% estimate was determined.

ANSWER:

(a)

The referenced quote applies to a Carbon Charge during the years 2024 to 2034. Based on Table A3-1 analysis for this period, the 63.5% equals the expected LTA thermal displacement from winter EPA deliveries (19.563 GWh at row 5) divided by LTA EPA deliveries (30.8 GWh at row 1). Similarly, for the years 2035 and the balance of the EPA term, this percentage is adjusted to 48.7% (15.003/30.8).

ISSUE: **Price for electricity under electricity purchase agreement**

REFERENCE: **OIC 2019/25, page 2, PDF page 2, Section 1 definitions**

QUOTE: "'Independent power production facility' means a facility in Yukon…"

QUESTION:

a) Is the pricing under OIC 2019/25 only applicable to an independent power production facility?

ANSWER:

(a)

Yes.

ISSUE: **Carbon charges**

REFERENCE: **Application, page 11, PDF page 14**

QUOTE: "If in the future a carbon charge is approved by YUB for recovery through customer rates, THELP can get paid up to 50% of YEC's added cost saving from thermal displacement."

QUESTION:

a) Please confirm if the CPI includes any carbon taxes levied on the ratepayer.

b) Please confirm if any additional charge due to a carbon tax would in effect be double dipping.

ANSWER:

(a)

YEC does not understand the basis of this question, as "CPI" is not referenced in the above quote or in the EPA sections addressing the carbon taxes.

(b)

No, there would not be any double dipping.

The EPA energy price paid to THELP is based on forecast fuel cost savings that YEC secures due to displacement of LTA thermal generation as a result of the EPA winter energy deliveries. If a carbon tax is approved by the YUB for recovery though customer rates, then YEC forecast fuel cost savings secured by YEC due to displacement of LTA thermal generation is increased. Under the related EPA pricing provision, THELP would get up to 50% of this added YEC cost saving.

ISSUE:

REFERENCE: **Application, Appendix B, page B-10, PDF page 54**

QUOTE: 2024 and 2035 Winter Energy Prices: the winter energy price has been estimated for 2024 based on expected loads with mines connected, and escalated at 50% of CPI each subsequent year until 2035.

QUESTION:

a) Please explain how the Consumer Price index (CPI) is derived.

ANSWER:

(a)

The CPI is defined in Appendix A of the EPA, section 1.43 as follows:

> **"CPI"** means the Consumer Price Index for Canada, All Items (Not Seasonally Adjusted) as published by Statistics Canada in table 18-10-0004-01 or its equivalent substitute or replacement as agreed to by the Parties, acting reasonably. For clarity, the CPI index value for January, 2019 is 133.6.

ISSUE: **Alternatives to the project**

REFERENCE: **YEC 2016 Resource Plan Part 2, page 5-31, PDF page 3**

QUOTE:

Table 5-27. Small Hydro Resource Option Technical and Financial Attributes

Annual Energy GWh/yr	Firm Energy GWh/yr	Installed Capacity MW	Dependable Capacity MW	Levelized Cost of Energy $/kWh	Levelized Cost of Capacity $/kW·yr	Project Life Years	Lead Time Years	Dispatch-able Y/N
Drury Lake								
31.7	31.7	8.1	8.1	0.19	700	65	6	Y
Tutshi Windy Arm								
56.6	56.3	7.2	7.2	0.14	1100	65	6	Y
Wolf River								
95.6	86.9	20	2.8	0.14	700	65	6	Y
Finlayson River								
138.9	138.9	17.6	17.6	0.12	1000	65	6	Y
Atlin/Pine Creek								
36.1	22.3	8	5.5	0.13	806	30	6	Y
Anvil Creek								
41.3	31	9.8	2.5	0.17	700	65	6	Y

QUESTION:

a) Please explore the financial ramifications for the Yukon ratepayers for the projects Drury Lake, Atlin/Pine Creek and Anvil Creek.

b) Would the energy produced by a Yukon Consortium for a project located in Yukon fall under OIC 2019/25?

c) In financial terms, what is the difference between this EPA and projects that would fall within OIC 2019/25?

ANSWER:

(a)

The table provided in the preamble is for small hydro projects reviewed in YEC's 2016 Resource Plan. Since then, YEC updated the small hydro resource options in the 10-Year Renewable Electricity Plan.

For the 10-Year Renewable Electricity Plan YEC engaged Knight Piésold Ltd. (KP) to update and further develop a desktop review of the potential hydroelectric projects in Yukon and northern BC. This study resulted in a refined and updated list of five small hydroelectric projects of interest, Atlin and four others, with capacities ranging from 8 MW to 13 MW and with four of the five having storage capabilities.

Table 3, Refined List of Future Potential Resource Options, of the 10-Year Renewable Electricity Plan provides an updated list of small hydro options [the technical report is available at YUB-YEC-1-32, Attachment 1].

To date the review of the referenced small hydro projects by Yukon Energy were limited to the desktop level pre-feasibility assessments conducted for 2016 Resource Plan and 10-Year Renewable Electricity Plan.[1] At this time, the financial ramifications to Yukon ratepayers is limited to the cost of those studies. Potential future financial ramifications to Yukon ratepayers if each project was to be developed will depend on subsequent financial assessments during project feasibility and implementation stages of development.

No feasibility studies or ratepayer impact analysis were prepared for Drury Lake or Anvil Creek, while Atlin Hydro ratepayer impact analysis are prepared for the EPA purposes. The following is specifically noted regarding the three projects referenced in the question.

Atlin Hydro Expansion

Atlin Hydro Expansion was selected in the 10-Year Renewable Electricity Plan as a potential near term option in the portfolio because of its ability to supply both dependable capacity and firm energy, and because of its significantly shorter project development timeline when compared to other greenfield hydro options. Estimates of project

[1] The 2016 Resource Plan also notes previous studies including 1989, 1990, 1991 Hydro Investigations [S. Demers] and Assessment of Potential Hydro Sites [KGS Group, 2008].

deliverables (6 MW dependable capacity and 44.7 GWh/yr energy) have changed significantly today, as have the estimated costs at $131 million. The levelized cost of energy was estimated at $0.17/kWh without grants ($0.10/kWh with grants) and levelized cost of capacity at $1,270/kW-year without grants ($708/kW-yr with grants).

It was understood that the Atlin project would be developed as an expansion of an existing hydro facility owned by the local First Nation, and that the project would therefore likely be under an EPA with YEC.

The current Submission details EPA capacity and energy pricing for the Atlin project which includes the following [detailed table provided as Table 3-1 in the Submission]:

Pricing	**2024-2034**	**2035 & Beyond**
Energy Delivered		
Firm Winter Energy Price (Jan-May,Sept-Dec) (first 25.2 GWh delivered in winter)	$0.132/kWh in 2024 plus 1/2 CPI	$0.107/kWh in 2024 plus 1/2 CPI after
Non-Firm Winter Energy Price (all energy after first 25.2 GWh delivered)	$0.072/kWh in 2024 plus 1/2 CPI	$0.027/kWh in 2024 plus 1/2 CPI after
Dependable Plant Capacity Committed		
LCOC Reference Price	$200/kW-yr in Dec. 2023 plus CPI after	

The capacity and energy pricing for the Atlin EPA was determined based on benefits the project is expected to provide to the YIS, including dependable capacity during critical winter period and LTA thermal displacements benefits as discussed in the Submission.

The financial ramifications for ratepayers are severely constrained by the EPA (i.e., development and project costs risks are borne by THELP, and EPA prices are based on expected thermal option costs rather than actual project costs).

Drury Lake

The Drury site was evaluated as both a run of river project and a storage project. However, only the storage option was included as part of five small hydroelectric projects of interest [run of river option was not attractive due to low winter energy].

The project scale was identified to have 10 MW dependable capacity with 30.6 GWh annual energy at a capital cost of $110.5 million. The levelized cost of energy based on this pre-feasibility assessment was estimated at $0.21/kWh and levelized cost of capacity at $635/kW-year.

Experience with hydro projects demonstrates potential for material cost escalation as assessments move through from pre-feasibility to feasibility studies, from studies to final design and contracting, and from contracting to final commissioning. Drury Creek is a greenfield site that was expected to require YEC to be the party developing the project.

YEC does not have detailed ratepayer impact analysis for the project as it requires consideration of LTA thermal displacement rather than using project levelized cost of energy based on total energy generated over the year.

Anvil Creek

The project was not included as part of shortlisted small hydro projects in the 10-Year Renewable Electricity Plan.

A few run-of-river configurations were considered up and down Anvil Creek. The project location has previously been associated with Anvil Lake, a site that does not offer the same generating opportunities. The most attractive options for Anvil Creek assume long tunnels, resulting in average to higher LCOE returns, as such the project was not shortlisted. It was only possible to fully regulate the river for winter generation with a very tall dam structure, which proved to be cost prohibitive (i.e., $1 billion for 30 MW of firm winter generation).

(b)

In general, subject to meeting all relevant regulations and terms, a renewable energy hydro project located in Yukon, owned by parties other than the utilities, and supplying the YIS under an EPA with YEC would fall under OIC 2019/25 with all energy delivered priced on the basis of the applicable blend fuel thermal price last approved by the Board and inflated each year thereafter at 50% of CPI.

(c)

Under OIC 2019/25 for the on-grid projects:

- The price paid by an electrical utility for a kWh of electricity under an on-grid electricity purchase agreement is to be based on the utility's average blended fuel price per kWh for thermal generation most recently approved by the board before the date on which the agreement takes effect.

- This price is subject to annual escalation at 50% of the CPI increase.

- Provision is also made for compensation (section 5(1)) as well as for utility recovery of costs (section 2).

In summary, OIC 2019/25 requires that for each kWh delivered the utility must pay the last approved blended fuel cost regardless of the thermal displacement benefits of that delivered energy.

In contrast, the Atlin EPA firm and non-firm prices have been set based on LTA thermal displacement benefits. Atlin EPA pricing also focuses on energy delivered during the "winter" period [defined as Jan-May, Sep-Dec], while for SOP IPP projects the utility pays the specified price for all annual generation.

The Atlin EPA also includes a capacity payment price which is not included in the OIC 2019/25.

Section 4.2 of YEC's Submission provides the following assessment of the difference between this EPA and equivalent SOP IPP developments under OIC 2019/25:

> "The EPA effect on customer rates is materially lower than equivalent SOP IPP renewable supplies. Total annual cost at 2024$ prices for EPA deliveries to YEC for LTA energy and dependable capacity equals $5.3 million/year until the end of 2034, and $4.5 million/year thereafter.[2]

[2] The $5.3 million/year (2024$) until the end of 2034 assumes 8.0 MW dependable capacity ($1.6 million/year) plus 30.8 GWh/year winter delivered energy ($3.7 million/year per Appendix A, Table A3-2). The Project is capable of providing 5.4 GWh/year during summer, but no summer deliveries are assumed to be required from the Project given the forecast surplus of summer renewable energy. If 5.4 GWh of summer energy was required from the Project, and YEC's approved blended fuel cost (2024$) was $0.19/kWh, the added cost would be $0.5 million/year (price at 50% of the approved blended fuel cost).

- In contrast, SOP IPP deliveries for renewable projects with the same annual LTA energy delivery capability (36.2 GWh/year including summer period energy) and the same 2024$ YEC blended fuel cost of $0.19/kWh would cost YEC $6.88 million/yr. for energy only.

- Additional costs would also be needed with SOP IPP options in order to provide the equivalent 8.0 MW of dependable capacity from another new source. The least costly new source would likely be new thermal generation with an LCOC (2024$) of at least $200/kW-year or $1.6 million/year for 8.0 MW."

ISSUE: **BC Hydro Supply Agreement**

REFERENCE: **Application, page 2, PDF page 5**

QUOTE: “In 2009 the TRTFN, through an affiliate of THELP, developed a 2.1 MW hydroelectric power station at Atlin, BC, on Pine Creek with hydro storage at Surprise Lake (the "Existing Plant"). The Existing Plant has an existing electricity purchase agreement with BC Hydro to supply BC Hydro load at Atlin until 2033. THELP expects that a further EPA will be negotiated with BC Hydro for supply after 2033.”

QUESTION:

a) Please provide a copy of the agreement referenced above.

ANSWER:

(a)

Please see response to YUB-YEC-1-8.