VANCOUVER ISLAND – CALL FOR TENDERS

QUANTITATIVE EVALUATION METHODOLOGY

(Revised: 6 August 2004)

1. OVERALL OBJECTIVES:

1.1 ***Background:*** The quantitative evaluation methodology ("QEM") is designed to identify the most cost effective method, consistent with the BCUC decision on the VIGP project, of meeting the capacity shortfall on Vancouver Island arising from the retirement, for planning purposes, of the existing high-voltage direct-current ("HVDC") cables.

The BCUC's decision on the VIGP project concluded that the CFT should address the capacity shortfall on Vancouver Island by focusing on generation solutions on the island. The BCUC indicated that it should be possible to develop a simplified net present value ("NPV") model specifically for the CFT, that the model should be available to bidders in advance and that it should be limited to on-island generation costs, without the need to consider future impacts to electricity transmission or generation on the British Columbia mainland. BC Hydro has developed an NPV model reflecting the QEM, in response to these views of the BCUC.

1.2 ***Objectives:*** The objective of the QEM is to ascertain **the most cost effective solution for BC Hydro's ratepayers, having regard to the price and other impacts of each possible portfolio of resource options.** The development of the evaluation methodology has been guided by the need for transparency and fairness to bidders.

- ***Transparency:***
  - Evaluation criteria and methodology are disclosed.
  - Questions and answers relative to the CFT, including evaluation issues, are posted to the website without attribution to particular bidders in accordance with the terms of the CFT.
  - Assumptions and other data (e.g. the Gas Price Forecast and input to the Electricity Price Forecasts) are sourced from reputable, independent agencies, so far as possible.
  - Bidders are given spreadsheet tools, which are the same tools that will be used by the Quantitative Evaluation Committee ("QEC") in determining Net Tender Cost and Net Portfolio Cost, so bidders can construct and run their own scenarios.
- ***Fairness to Bidders:***
  - Consistent criteria and evaluation methodology will be applied to every Tender and Portfolio.

- Upon passing Mandatory Criteria and the Development Risk Assessment, a quantitative evaluation will be carried out, using information supplied by the bidder, applied against a set of uniform assumptions and other input data. The QEM does not involve subjective assessments, other than those applied to construct the underlying assumptions and input data of the evaluation model.

- Consideration of Mandatory Criteria and Development Risk Assessment will be carried out by the Submission Evaluation Committee ("SEC"). The quantitative evaluation will be carried out by the QEC. These committees are separate and have no overlapping membership. The QEC is privy only to the necessary quantitative data and blind to other data available to the SEC.

- The QEM recognizes and values price and other key quantitative data and technical inputs from Tenders (e.g. dispatchability, treatment of fuel supply, location, etc.).

- Fairness will be monitored throughout by the Independent Reviewer, who has full access to the evaluation proceedings. The Independent Reviewer will provide a Final Report on fairness and impartiality relative to the CFT process and its execution.

2. OVERVIEW OF QUANTITATIVE EVALUATION METHODOLOGY:

Words and phrases defined in the CFT or the Final Form EPA and used in the QEM have the meanings given in the CFT or the Final Form EPA, unless otherwise defined herein.

The CFT has been designed to consider a wide range of possible resource options. Bidders have considerable choice in terms of technology, project size, fuel risk and other project attributes. Accordingly, the QEM must provide for the various resource options pre-qualified under the CFT.

Tender options under the CFT are outlined in section 4.3 of Addendum 18.

All EPAs awarded under the CFT must have an Initial Term of 25 years from COD. The QEM evaluates Tenders and Portfolios over that term, without regard to any renewal rights. The methodology models 25 years of monthly cash flows using Excel spreadsheets that have been developed specifically for this CFT.

The QEM assembles all possible Portfolios using a Tender or Tenders, which meet the Mandatory Criteria and pass the Development Risk Assessment, and gives effect to mutually exclusive Tenders, if any. Portfolios must aggregate not less than the CFT Minimum Capacity and not more than the CFT Maximum Capacity, based on tendered Bid Capacities, adjusted to average degraded capacities at AAC, and adjusted for Capacity Losses (as further described herein) on a Portfolio basis.

The QEM assesses and determines (i) the NPV of costs and benefits to BC Hydro of the capacity and associated energy of each Tender within a particular Portfolio (“Net Tender Cost”), and (ii) the NPV of each Portfolio, after giving effect to certain other specified impacts of that Portfolio on BC Hydro and its ratepayers (“Net Portfolio Cost”).

There are two spreadsheets: a Tender Spreadsheet which computes the Net Tender Cost (section 4.3) for each Tender, and a Portfolio Spreadsheet which computes the Net Portfolio Cost (section 4.5) for each Portfolio.

The Tender(s) included in the Portfolio having the lowest Net Portfolio Cost are recommended for an award of EPA(s), subject to section 17 of the CFT, as amended by section 11 of Addendum 10.

The assessment of Tenders follows the 6-step process outlined below, subject to section 17 of the CFT, as amended. The QEM focuses on Steps 3-5 inclusive.

- ***Qualitative Assessment:***
  - ***Step 1 – Mandatory Criteria:*** The SEC re-assesses each bidder and project tendered against the Mandatory Criteria, including in-depth assessments of financial capability and creditworthiness and fuel supply certainty.
  - ***Step 2 – Development Risk Assessment:*** The SEC conducts a Development Risk Assessment of the likelihood that projects will meet the guaranteed COD of 1 May 2007, having regard to current project status.
- ***Quantitative Assessment:***
  - ***Step 3 – Net Tender Cost (Section 4.3):*** Carried out by the QEC.
  - ***Step 4 – Portfolio Assembly (Section 4.4):*** Carried out by the QEC.
  - ***Step 5 – Net Portfolio Cost (Section 4.5):*** Carried out by the QEC.
- ***Decision:***
  - ***Step 6 – Recommendation (Section 5):*** EPA awards are recommended to BC Hydro senior management and board of directors, based on the results of Step 5.

3. DATA SOURCES FOR THE QUANTITATIVE EVALUATION:

3.1 ***Sourcing the Data:*** All data used in the QEM are derived from one of three sources:

- the Tenders,

- independent third parties, and
- BC Hydro.

The information derived from each source is described below.

3.2 ***Data Sourced from the Tender:*** Each bidder must quote or provide specified information in its Tender, which will be used in the quantitative evaluation. This information impacts the value of the Tender to BC Hydro and accordingly impacts the quantitative evaluation. This information includes:

- Capital Charge ("CC") - $/MW/month, fixed, no escalation.
- Operation and Maintenance Charge ("OMC") - $/MW/month, with optional provision for escalation.
- Energy Charge ("EC") - $/MWh, with optional provision for escalation.
- Bid Capacity – MW, expressed "clean and new".
- Capacity Conversion Table - relative % adjustments for temperature and humidity.
- Capacity Degradation Factor - % over the Initial Term.
- Scheduled Planned Outage Allowance Hours:
    - Major Maintenance Years – hours/year.
    - Non-Major Maintenance Years – hours/year.
    - Major Maintenance Interval, expressed as the earlier of:
        - Fixed frequency of Major Maintenance Years, or,
        - Cumulative equivalent operating hours ("EOH") between Major Maintenance.
    - Data for the determination of EOH:
        - EOH applicable to operating hours at less than full output, if applicable; and
        - EOH per Start for Dispatchable/Peaking Capacity plants, or
        - EOH per Hot, Warm and Cold Start for Dispatchable/Non-Peaking Capacity plants.

  - Note: Major and non-Major Maintenance must be scheduled during the months of April to June inclusive, regardless of expiry of tendered cumulative EOH.

- Minimum Turndown ("MTD"), if applicable – minimum output, expressed as a % of full output, to which the plant may be turned down. (Note: MTD, if any, tendered for a Dispatchable/Peaking Capacity plant is not modeled by the QEM.)

- For gas-fired plants, confirmation that the bidder has elected Option #1 – *No Tolling* or Option #2 – *Full Tolling*.

- For all gas-fired tolling plants:

  - Guaranteed Heat Rate at COD at full output (baseload) and at MTD, if applicable, in each case at average ambient conditions ("AAC") – GJ/GWh Higher Heating Value ("HHV").

  - Heat Rate Conversion Table - relative % adjustments for temperature and humidity.

  - Heat Rate Degradation Factor - % over the Initial Term.

- Designation of the plant as (i) Must Run/Full Capacity, (ii) Must Run/Minimum Turndown Capacity, (iii) Dispatchable/Peaking Capacity or (iv) Dispatchable/Non-Peaking Capacity, in accordance with the classification rules set out in section 4.1. Bidders may also specify one of (i) or (ii) for certain months, and one of (i) to (iv) inclusive for all other months (a "Split Year Designation").

- For Dispatchable/Peaking Capacity and Dispatchable/Non-Peaking Capacity plants:

  - Start Up Cost ("SUC"), with optional provision for escalation, and Start Up Fuel ("SUF") for gas-fired tolling plants. In the case of Dispatchable/Peaking Capacity, one SUC, and, if applicable, one SUF, is tendered for Starts. In the case of Dispatchable/Non-Peaking Capacity separate SUCs and, if applicable, separate SUFs, are tendered for each of Hot, Warm and Cold Starts.

  - Maximum Starts per Year ("MSY") for Dispatchable/Peaking Capacity plants, or

  - MSY for Dispatchable/Non-Peaking Capacity as to each of Hot, Warm and Cold Starts.

  - Ramp Up Time ("RUT") per Start for Dispatchable/Peaking Capacity plants, or

- o RUT for Dispatchable/Non-Peaking Capacity for each of Hot, Warm and Cold Starts.

Note that negative amounts may not be tendered (other than as entries in Capacity Conversion and Heat Rate Conversion tables).

3.3 ***Data Sourced from Independent Third Parties:***

3.3.1 Natural Gas Price Forecast - General: The QEM will use a single natural gas price forecast. The selected forecast is the Energy Information Administration Reference Case issued in January 2004, adjusted for basis differential, currency exchange rate and extrapolation to the expiry of the Initial Term, as outlined in sections 3.3.2, 3.4.5, and 3.3.4, and subject to updates ("Gas Price Forecast"). All references herein to "gas commodity cost(s)" or "forecast gas price(s)" mean costs or prices determined by the Gas Price Forecast.

This Gas Price Forecast will be used in the quantitative evaluation to develop two corresponding electricity price forecasts ("Electricity Price Forecasts") as outlined in section 3.4.2 and 3.4.3. These forecasts are used (i) to model plant dispatch, and (ii) to value energy. All references herein to "forecast electricity price(s)" mean prices determined by the Electricity Price Forecasts.

3.3.2 Natural Gas Forecast - Basis Differential: The Gas Price Forecast is referenced to Henry Hub – the most widely traded hub for natural gas transactions in North America. The closest relevant trading hub for CFT purposes is at Sumas, Washington. Accordingly, the gas prices in the forecast are adjusted to account for the basis differential between Henry Hub and Sumas. The Henry Hub to Sumas differential is provided by Confer Consulting Ltd. This value is based on an analysis of past and forecast transportation costs between North American gas market hubs.

3.3.3 Natural Gas Forecast Updates: The Gas Price Forecast is subject to update only as provided in Addendum 19.

3.3.4 Natural Gas Forecast Periods: The Gas Price Forecast has a term of 20 years. Since the CFT is evaluating Tenders and Portfolios having a 25-year term from 2007, the forecast is escalated by best fit linear extrapolation over the balance of the forecast period.

3.3.5 Network Effects:

Network Upgrade Costs:

Network Upgrade Costs will be reflected in the quantitative evaluation at the Portfolio level. For purposes of the QEM, Network Upgrade Costs will be determined for each Portfolio as (i) the estimate of Network Upgrade Costs provided by BCTC for each Portfolio, based on information provided by bidders in interconnection applications and Portfolio information provided by BC Hydro, plus (ii) an amount equal to 10% of the estimate as a contingency allowance in respect of BC Hydro's exposure to the risk of recovery of such costs in the event of EPA termination, and (iii) the estimate of the amount, if any, of Interconnection Costs to be borne by BC Hydro due to the "Portfolio effect" described in section 9 of Addendum 16.

Energy Losses:

Energy Losses will be reflected in the quantitative evaluation at the Portfolio level. The value of Energy Losses will be determined by BCTC as an estimate of the NPV of the value of those transmission losses expected on Vancouver Island during the Initial Term resulting from the addition of the projects included in the Portfolio relative to those transmission losses expected in the event that no EPAs were awarded under the CFT. Energy Losses may be either positive or negative representing an increase or decrease, respectively, in expected transmission losses. BC Hydro will determine an expected output profile for each plant in a Portfolio, and will provide these output profiles to BCTC in order for them to calculate Energy Losses. The incremental physical Energy Loss, whether positive or negative, will be valued using the average of the Electricity Price Forecasts, which will also be supplied to BCTC by BC Hydro.

3.4 ***Data Sourced from BC Hydro:***

3.4.1 Electricity Price Forecasts - General: Two Electricity Price Forecasts are used. Each forecast corresponds to the Gas Price Forecast. If the Gas Price Forecast is updated, then the Electricity Price Forecasts will be updated to reflect the impact only of the updated Gas Price Forecast.

Electricity Price Forecasts are used in modeling plant dispatch and calculating the Energy Margin described in section 4.

3.4.2 100% Capital Cost Recovery Forecast: The first Electricity Price Forecast ("100% Capital Cost Recovery Forecast") reflects prices at Heavy Load Hours ("HLH") and Light Load Hours ("LLH") with monthly resolution. The forecast comprises two components:

(a) *Years 2007 to 2012, inclusive:* The forecast electricity prices at the B.C.-U.S. border are based on a forecast of supply and demand for electricity and the cost drivers expected to prevail. They are modeled under a computer simulation of the hourly supply-demand balance for the Western Electricity Coordinating Council (WECC) regional market, which includes the Western U.S. states, British Columbia and Alberta. The Henwood Energy Services simulation software ("Henwood Model") is used, with certain inputs based on BC Hydro's knowledge and system, which, among other modeling details outlined below, accounts for transmission costs and limitations. The dispatch cost of the marginal resource at the point where supply and demand are in equilibrium determines the forecast electricity price for each hour. Monthly average prices are obtained by aggregating the computed hourly prices. Additional modeling details include:

- Hourly simulation of 20+ WECC areas;
- Expected WECC load growth (2% per annum);
- Expected hourly load shape (estimated from historical hourly load data from 1993 to 2000);
- BC Hydro electricity load forecast and resource plan;
- Average hydrological conditions throughout WECC;
- Existing WECC resource base less expected retirements plus expected additions;
- Generic resources added to maintain reserve margin targets for WECC sub-regions;

- Expected inflation; and
- Expected long-term transmission limits, losses and costs.

(b) *Year 2013 to 2031, inclusive:* The forecast electricity prices are determined by reference to the estimated unit cost of the most economical resource addition, currently a natural gas-fired, F-series combined cycle gas turbine (CCGT). Capital and operating costs are based primarily on third party sources. Key costing details (all costs in real 2002 dollars) include:

- Greenfield project (i.e. a new project, not a re-powering of an existing facility) located in the Lower Mainland of British Columbia;
- Capacity: 262 MW (average over life);
- Capital Cost: U.S.$200 million;
- Debt/Equity Ratio: 72/28;
- Return on Equity: 18.3%;
- Capital cost/return recovery: 100% over 25 years;
- Variable operating and maintenance cost: 3.15 U.S.$/MWh;
- Fixed operating and maintenance cost: 2.15 U.S.$/MWh;
- Gas Price Forecast;
- British Columbia motor fuel tax: 7%;
- Heat Rate: 6,863 MMBtu/GWh or 7,240 GJ/GWh HHV, average over life;
- Unit average availability: 91.3%; and
- Seasonal shape of prices is estimated from the shape of the 2007-2012 forecast of prices from the Henwood Model.

3.4.3 <u>25% Capital Cost Recovery Forecast:</u> The second Electricity Price Forecast ("25% Capital Cost Recovery Forecast") is determined as follows:

- *Years 2007 to 2012, inclusive:* Forecast electricity prices are the lesser of the price determined by (i) the Henwood Model, as described in section 3.4.2(a) and (ii) the unit cost by reference to a CCGT as described in section 3.4.2(b), but with a 25% recovery of capital (rather than 100%) over 25 years.

- *Years 2013 to 2031, inclusive:* Electricity prices are forecast as the price determined by the unit cost by reference to a CCGT as described in section 3.4.2(b), but with a 25% recovery of capital (rather than 100%) over 25 years.

The 25% Capital Cost Recovery Forecast reflects the possible future outcome in which market prices do not reflect an all-in fully recovered cost of new gas-fired generation. This may be due to:

- New, more efficient generation technologies;
- Retirements of older plants;

- Regulatory/political events (such as market price caps);
- Effects of generation cross-subsidies and capacity charges; and
- Sustained overbuilds in generation.

This forecast provides a lower market heat rate than the 100% Capital Cost Recovery Forecast and a fundamentally different gas-to-electricity price relationship.

3.4.4 Gas Transportation Costs for Gas-fired Tolling Plants: For the purpose of evaluating Tenders in respect of gas-fired tolling plants or Portfolios in which such Tenders are included, optimal gas transportation solutions and corresponding cost estimates must be determined for service from Huntingdon/Sumas to the plant gate. Solutions may include firm and/or interruptible service utilizing GSX and/or upgrades, if necessary, on the Terasen Gas (Vancouver Island) Inc. and/or Terasen Gas Inc. (collectively "Terasen") systems. Firm service costs may reflect a long-term fixed rate(s) or an estimated cost of service rate or alternative rate structure.

For each Portfolio, the optimal solution will be determined having regard to the gas demand and operating capabilities of tendered plants, including dual fuel capability, if any, the estimated availability of interruptible service, and BC Hydro's need for a reliable electricity resource on Vancouver Island. Therefore the optimal solution for a particular Portfolio may consist of firm gas transportation service only, or may include interruptible gas transportation service to a specified aggregate limit for that Portfolio.

The optimal solution for gas-fired tolling plants without dual fuel capability has been determined to be firm gas transportation service. Gas-fired tolling plants with dual fuel capability may be optimized with firm and/or interruptible service, depending on the factors outlined above. For this purpose, "dual fuel capability" means that the plant meets the standards stipulated in Appendix 17, Part I or Part J, as applicable, of the Final Form EPA.

For purposes of Tender evaluation, where interruptible gas transportation service is determined to be optimal, an estimated unit rate for interruptible transportation, if any, must be determined and taken into account as part of Tender Variable Cost (hereinafter defined) in calculating the Net Tender Cost. For purposes of Portfolio evaluation, where firm gas transportation is determined to be optimal, an estimate of the NPV of firm gas transportation costs must be determined and taken into account in determining Net Portfolio Cost.

Recognizing that a Tender may form part of more than one Portfolio, a Tender in respect of a gas-fired tolling plant with dual fuel capability will be evaluated twice as to Net Tender Cost – once assuming interruptible service and once assuming firm service. When evaluating a particular Portfolio that includes that Tender, the Net Tender Cost will be used, which corresponds to the optimal gas transportation solution for that Portfolio.

BC Hydro will determine for each Portfolio (i) the optimal gas transportation solution, (ii) an estimate of the NPV of firm gas transportation service, if any, and (iii) an estimate of the unit rate of interruptible gas transportation service, all based on a consideration of all Tenders and Portfolios from pre-qualified bidders, and discussions with, and estimates and data furnished by, Terasen and/or any regulatory proceedings relative to gas transportation agreements, rates and/or rate designs. These determinations will be reported to the QEC before envelopes containing Price Information Forms are opened.

Gas transportation cost estimates will include (i) consideration of any incremental cost or cost saving to BC Hydro in providing gas transportation to service the Island Cogeneration Project at Elk Falls on Vancouver Island that is likely to result from the award of an EPA under the CFT in respect of a gas-fired tolling plant and (ii) as to firm gas transportation cost estimates, an amount equal to 10% of the estimated cost as a contingency allowance in respect of BC Hydro's exposure to the risk of recovery of such costs in the event of EPA termination.

3.4.5 Currency Exchange Rate: The evaluation is performed in Canadian dollars. Bidders must provide Tender information in $Cdn. The gas and electricity price forecasts on which the QEM forecasts are based are in $U.S. These forecasts will be converted to $Cdn using forward market exchange rates. BC Hydro may update the forward market exchange rates used in the evaluation as provided in Addendum 19.

3.4.6 Discount Rate: Present values will be calculated using an 8% nominal discount rate, based on BC Hydro's current weighted average cost of capital.

3.4.7 Inflation: The evaluation methodology assumes inflation at 2.1% per annum.

3.4.8 VIGP Asset Price Credit: Portfolios including a Tender in respect of which the bidder has made the VIGP Election are credited with $50 million ("VIGP Asset Price"), which is the price payable to BC Hydro for the bidder's acquisition of the VIGP Development Assets. BC Hydro has determined the VIGP Asset Price based on its assessment of the value of VIGP development work done to date, assuming issue of Material Permits before the Tender Closing Time.

3.4.9 VIGP Asset Salvage Value: Portfolios which do not include a Tender in respect of which the bidder has made the VIGP Election are credited with $14 million, being BC Hydro's estimate of the net realizable value of VIGP Development Assets, assuming that VIGP is not constructed ("VIGP Salvage Value").

4. APPLYING THE DATA:

4.1 **Classifying Plants by Dispatch Rights:** Each plant tendered will be classified strictly on information contained in the Tender, as one of the following:

- *Must Run/Full Capacity:* A plant in respect of which BC Hydro has no dispatch or turn down rights or in respect of which any tendered MSY is less, or tendered RUT is more, than that required to qualify as a Dispatchable/Non-Peaking Capacity plant, as defined below.

- *Must Run/Minimum Turndown Capacity:* A plant in respect of which BC Hydro has no right to dispatch the plant off or in respect of which any tendered MSY is less, or tendered RUT is more, than that required to qualify as a Dispatchable/Non-Peaking Capacity plant, as defined below, but BC Hydro does have a right to turn down the plant to any output that is not less than a tendered MTD.

- *Dispatchable/Non-Peaking Capacity:* A plant, which does not qualify as a Dispatchable/Peaking Capacity plant, as defined below, and in respect of which BC Hydro has dispatch rights under which it may dispatch the plant on or off, provided that the tendered MSY is not less than 130% of the Estimated Starts per Year (“**ESY”)** for Dispatchable/Non-Peaking Plants determined in accordance with section 4.2, and the tendered RUT does not exceed 12 hours for Cold Starts, 8 hours for Warm Starts and 4 hours for Hot Starts. The tendered MSY for each of Cold, Hot and Warm Starts will be compared to 130% of ESY (“Starts Threshhold”) allocated to each of Cold, Hot and Warm Starts. However, if the tendered MSY for cold starts exceeds the Starts Threshold for Cold Starts, the excess cold MSY will be treated as Warm Starts in applying the Starts Threshhold to Warm Starts, and if quoted warm MSY for Warm Starts plus excess cold MSY not utilized as aforesaid exceeds the Starts Threshhold for Warm Starts, then that excess will be treated as Hot Starts in applying the Starts Threshhold to Hot Starts. A Dispatchable/Non-Peaking Capacity plant may also have a tendered MTD, which is applicable to circumstances in which the plant is turned down, but not dispatched-off.

- *Dispatchable/Peaking Capacity:* A plant in respect of which BC Hydro has dispatch rights under which it may dispatch the plant on at full output or off, and the tendered RUT is not more than 60 minutes, provided that the tendered MSY is not less than 130% of ESY for Dispatchable/Peaking Plants determined in accordance with section 4.2. A Dispatchable/Peaking Capacity plant may also have a tendered MTD, which is applicable to circumstances in which the plant is turned down, but not dispatched-off. However, any tendered MTD for such a plant is not modeled or otherwise considered in the evaluation.

A bidder is permitted to designate in its Tender its plant as one of the “Must Run” classifications for specified months in the year, and one of the other “Must Run” classifications or one of the “Dispatchable” classifications for all other months in the year. This Split Year Designation will then apply under the evaluation and in the EPA for all years in the Term. If a bidder designates its plant as “Dispatchable” for a portion only of each year, then for purposes of the foregoing classification and the evaluation, ESY, determined according to section 4.2, will be prorated accordingly. In the case of a Split Year Designation, MSY should be tendered as the maximum number of Starts in all months of each year designated as “Dispatchable”.

The foregoing classification applies for evaluation purposes. However, the applicable terms of any EPA awarded will reflect the tendered data. For example, a plant, which is dispatchable may be classified as “Must Run” for evaluation purposes because tendered MSY is too low or tendered RUT is too long. But if an EPA is awarded, the agreement will reflect terms applicable to dispatchable plants, including whatever MSY and RUT was tendered.

4.2 **<u>Dispatchable Plants – Number of Starts per Year:</u>** For Dispatchable/Peaking Capacity and Dispatchable/Non-Peaking Capacity plants, the quantitative evaluation will calculate the NPV of the Start Up Expense (hereinafter defined) for each Tender as part of the determination of the Net Tender Cost. In order to determine the annual Start Up Expense, it is necessary to estimate the number of Starts expected to occur per year for each Dispatchable/Peaking Capacity and Dispatchable/Non-Peaking plant. For purposes only of executing the QEM, the ESY will be determined by the QEC based upon information contained in each Tender, in the case of

Dispatchable/Peaking Capacity for all Starts in the aggregate, and for Dispatchable/Non-Peaking Capacity plants for each of Cold, Hot and Warm Starts, as follows:

- *For Dispatchable/Peaking Capacity Plants:*
  - For plants with a heat rate of 10,000 GJ/GWh and above, ESY will be 115,
  - For plants with a heat rate of 7,000 GJ/GWh and below, ESY will be 65,
  - For plants with a heat rate between 10,000 GJ/GWh or 7,000 GJ/GWh, the ESY will be interpolated between 115 and 65.
- *For Dispatchable/Non-Peaking Capacity Plants:*
  - For plants with a heat rate of 10,000 GJ/GWh and above, ESY will be 75,
  - For plants with a heat rate of 6,500 GJ/GWh and below, ESY will be 60,
  - For plants with a heat rate between 10,000 GJ/GWh and 6,500 GJ/GWh, the ESY will be interpolated between 75 and 60.

For the purposes of applying the foregoing, (i) for gas-fired tolling plants, the Heat Rate will be the ratio of EC to the forecast gas price for 2007, plus the tendered Guaranteed Heat Rate, and (ii) for all other plants, a market heat rate will be imputed, determined as the ratio of EC to the forecast gas price for 2007.

In the case only of Dispatchable/Non-Peaking Capacity plants, total ESY will be allocated 20% to Cold Starts, 70% to Warm Starts and 10% to Hot Starts. “Hot”, “Warm”, and “Cold” Starts are defined in the EPA.

4.3 ***<u>Step 3 – Net Tender Cost:</u>***

4.3.1 <u>Formula:</u> The Net Tender Cost of each Tender is calculated as:

NPV of CC Payments + NPV of OMC Payments – NPV of Energy Margin + NPV of Start-Up Expense

The Net Tender Cost evaluation uses nominal dollars. All costs or margins are discounted using the nominal discount rate.

4.3.2 <u>Capital Charges and Operation & Maintenance Charges</u>: The NPV is the discounted stream of the annual Capital Charge Payments (“CC Payments”) and the Operation & Maintenance Charge Payments (“OMC Payments”), as tendered. The annual payments reflect other tendered information, including the OMC escalation rate, if tendered, and the Capacity Degradation Factor.

- CC Payment is a monthly charge paid to the Seller under the EPA, based on the Adjusted Bid Capacity (further adjusted for the Capacity Degradation Factor). This charge is not subject to any escalation.

- OMC Payment is a monthly charge paid to the Seller under the EPA, based on the Adjusted Bid Capacity (further adjusted for the Capacity Degradation Factor). This charge may be subject to escalation, as tendered by the bidder.

For each plant, the bidder's tendered Capacity Degradation Factor will be interpolated quarterly over the Initial Term and applied in determining capacity used to calculate CC Payments and OMC Payments.

For all evaluation purposes, other than Portfolio assembly under section 4.4, the QEM adjusts the tendered Bid Capacity by the average of the Capacity Conversion Factors for each ambient condition, weighted by the frequency of that condition, and the term "Adjusted Bid Capacity" used herein means the tendered Bid Capacity as so adjusted. Probability-weighted average factors are calculated for each month and for both HLH and LLH by taking, for each cell in the conversion table, the product of (i) the frequency of the particular ambient condition in either HLH or LLH for each month as applicable and (ii) the tendered conversion factor for that cell, and summing all such products for all the cells in the conversion table for each HLH and LLH monthly period. The frequency of the ambient conditions is derived using hourly relative humidity and dry bulb temperature for 1983-2002 inclusive, recorded at Victoria International Airport (Source: Climate Services, Environment Canada).

4.3.3 Energy Margin: The Energy Margin is determined for each Tender using the Gas Price Forecast and the two Electricity Price Forecasts. The dispatch pattern of each plant is modeled with monthly resolution. For Dispatchable/Peaking Capacity and Dispatchable/Non-Peaking plants, the dispatch will differ, based on the Electricity Price Forecast applied.

Heat Rate:

For gas-fired tolling plants, the bidder will tender a Heat Rate Degradation Factor that represents the expected degradation to occur over the Initial Term. This factor will be interpolated quarterly over the Initial Term and applied in determining heat rate used in calculating the Energy Margin.

For all evaluation purposes, the QEM adjusts the tendered Guaranteed Heat Rate by the average of the Heat Rate Conversion Factors for each ambient condition, weighted by the frequency of that condition, and the term "Adjusted Heat Rate" means the tendered Guaranteed Heat Rate as so adjusted. Probability-weighted average factors are calculated for each month and for both HLH and LLH by taking, for each cell in the conversion table, the product of (i) the frequency of the particular ambient condition in either HLH or LLH for each month as applicable and (ii) the tendered conversion factor for that cell, and summing all such products for all the cells in the conversion table for each HLH and LLH monthly period. The frequency of the ambient conditions is derived using hourly relative humidity and dry bulb temperature for 1983-2002 inclusive, recorded at Victoria International Airport (Source: Climate Services, Environment Canada).

Dispatch Modeling:

The following describes how the QEM models plant dispatch for purposes of determining the Energy Margin. If a bidder tenders its plant on the basis of a Split Year Designation, then the plant is classified for portions of each year accordingly, and the QEM models plant dispatch for each portion of every year based on the classification applicable to that portion of the year.

(a) *Must-Run Capacity Plants:* A Must-Run Capacity plant is dispatched-on in all periods. The unit is assumed to run at a 97% availability factor during the Peak Demand Months as defined in the EPA, and at a lesser utilization in the non-Peak Demand Months, based on the tendered Schedule Planned Outage Allowance Hours.

(b) *Must Run/Minimum Turndown Capacity Plant:* A Must Run/Minimum Turndown Capacity plant is not dispatched-off at any time. The model assumes that the plant will be turned down to the tendered MTD when the Tender Variable Cost exceeds the forecast electricity price.

(c) *Dispatchable/Non-Peaking Capacity Plants:* A Dispatchable/Non-Peaking Capacity plant is dispatched for each month as follows:

- o If the Tender Variable Cost is lower than both the LLH and HLH forecast electricity price in any month, the evaluation will dispatch the plant at full output for the entire month.

- o If the Tender Variable Cost is higher than the LLH forecast electricity price but lower than the HLH forecast electricity price, the model will:

    - o Compare the weighted average Tender Variable Cost, assuming Minimum Turndown in LLH, to the weighted average of the HLH and LLH forecast electricity price, assuming that the plant is operated at MTD during LLH,

    - o If the weighted average Tender Variable Cost is higher than the weighted average forecast electricity price, then the plant is dispatched-off during the entire month,

    - o If the weighted average Tender Variable Cost is lower than the weighted average forecast electricity price, then the plant is dispatched-on at full output during HLH and at MTD during LLH.

- o If the Tender Variable Cost is higher than both the LLH and HLH forecast price in any month, then the plant is dispatched-off for the entire month.

(d) *Dispatchable/Peaking Capacity Plants:* A Dispatchable/Peaking Capacity plant is dispatched-on if the Tender Variable Cost is less than the forecast electricity price. This comparison is performed for 24 periods each year (12 months, and HLH and LLH periods in each month). For evaluation purposes, any tendered MTD is ignored, and the plant is dispatched-on at full output or dispatched-off.

(e) *Reliability Override for All "Dispatchable" Plants:* In order to reflect appropriately BC Hydro's need for Dependable Capacity, the foregoing purely economic dispatch profiles for "Dispatchable" plants are subject to a minimum dispatch-on of 3% of all hours in each month of every year of the Initial Term (excluding April to June inclusive).

Calculating the Energy Margin:

For all plants:

Energy Margin = Hours in dispatch-on period x (Forecast Electricity Price – Tender Variable Cost) x Adjusted Bid Capacity (or Adjusted Bid Capacity x MTD, as applicable), further adjusted for the Capacity Degradation Factor

The QEM determines the Tender Variable Cost as follows:

- For all plants, other than gas-fired tolling plants:
    - Tender Variable Cost = Energy Charge, adjusted for escalation.
- For gas-fired tolling plants:
    - Tender Variable Cost = Energy Charge, adjusted for escalation, + (the forecast gas commodity costs + estimated interruptible gas transportation costs, if any) x the Adjusted Heat Rate (or in the case of plants for which MTD is tendered, the average Adjusted Heat Rate, weighted by output), further adjusted by the Heat Rate Degradation Factor.

Gas commodity costs are determined by the Gas Price Forecast and include an allowance of 2.5% for "System Gas", as defined in Terasen's General Terms and Conditions for Gas Transportation Service, as well as motor fuel tax at 7% on gas commodity costs, inclusive of System Gas costs.

4.3.4 Start Up Expense: Start Up Expense is applied to Dispatchable/Peaking Capacity and Dispatchable/Non-Peaking Capacity plants, but is not applied to Must Run/Full Capacity or Must Run/Minimum Turndown Capacity plants. Start Up Expense is calculated differently for gas-fired tolling and for non-tolling Dispatchable/Peaking Capacity and Dispatchable/Non-Peaking Capacity plants.

- *Gas-fired Tolling Dispatchable Plants:* Start Up Expense is calculated as fuel required for Starts (determined for evaluation purposes as tendered Start Up Fuel ("SUF") x forecast gas price x ESY + SUC, adjusted for escalation, if tendered x ESY).

- *All Other Dispatchable Plants:* Start Up Expense is calculated as tendered SUC, adjusted for escalation, if tendered x ESY.

4.3.5 Dual Fuel Capability: For evaluation purposes, gas-fired plants tendered with dual fuel capability, which meet EPA standards (summarized in section 3.4.4 above), are deemed to operate on natural gas only in determining fuel commodity cost. While operation on distillate may involve some incremental cost, including a degraded heat rate, that cost is not material to the evaluation due to the limited frequency of fuel switching and operating hours on distillate, so those costs are not modeled for evaluation purposes. However, as outlined in section 3.4.4, dual fuel capability is taken into account in determining optimal gas transportation solutions, which in turn may affect the competitiveness of a particular Tender.

Therefore, a bidder may tender a plant with alternate pricing - with and without dual fuel capability. The QEM will run that Tender separately for each of the no dual fuel and the dual fuel scenarios, and both scenarios will be used in the assembly of Portfolios under Step 4, as if they were separate, but mutually exclusive, Tenders. This will ensure that if the incremental cost of dual fuel capability is not offset by gas transportation cost savings, the alternate and lower cost no dual fuel scenario will be available for possible inclusion in a successful Portfolio.

4.3.6 Duct Firing Capability – Tolling: A bidder may tender a gas-fired tolling plant with duct firing capability, in which case the Tender will include a Duct Fired Bid Capacity, which is the incremental capacity attributable to duct firing, and a Non-Duct Fired Bid Capacity reflecting the plant output when operating without duct firing. The sum of these two tendered Capacities is the "Bid Capacity". The Tender will also include a Guaranteed Heat Rate ($GHR_{BASELOAD}$) applicable when operating without duct firing and a Guaranteed Heat Rate (GHR_{DF}) applicable to the entire output, inclusive of duct firing capacity, when operating with duct firing.

In evaluating such a Tender the QEC will:

- o first run a Net Tender Cost without duct firing, using (i) Non-Duct Fired Bid Capacity as Bid Capacity, (ii) the tendered pricing (CC, OMC and EC) and (iii) $GHR_{BASELOAD}$, and

- o next run a second Net Tender Cost using (i) Duct Fired Bid Capacity as the Bid Capacity, (ii) tendered pricing (CC, OMC and EC), and (iii) an "average Guaranteed Heat Rate", calculated as:

$$\frac{(GHR_{DF} \text{ X Bid Capacity}) - (GHR_{BASELOAD} \text{ X Non-Duct Fired Bid Capacity})}{\text{Bid Capacity} - \text{Non-Duct Fired Bid Capacity}}$$

The aggregate of these two Net Tender Costs will be the Net Tender Cost for that Tender.

A bidder may tender its plant with or without duct firing capability, with corresponding alternate pricing, and that will be treated as two, mutually exclusive Tenders. This will ensure that, if the incremental cost of duct firing capability is not offset by an incremental Energy Margin, the alternate and lower cost no duct firing scenario will be available for possible inclusion in a successful Portfolio.

4.4 ***<u>Step 4 – Portfolio Assembly:</u>***

The QEM assembles all possible Portfolios using a Tender or Tenders, which meet the Mandatory Criteria and pass the Development Risk Assessment, and gives effect to mutually exclusive Tenders, if any. Portfolios must aggregate not less than the CFT Minimum Capacity and not more than the CFT Maximum Capacity, based on tendered Bid Capacities. For the purpose of Portfolio assembly, Bid Capacities will be adjusted as follows:

- o Bid Capacities will be adjusted to average degraded capacities at AAC, and

- o Aggregate Bid Capacities of Portfolios will be further adjusted by subtracting the positive Capacity Loss associated with the Portfolio, if any, expressed on a MW basis, as determined by BCTC. For this purpose, Capacity Loss is the difference between (i) the average of the annual peak losses on the Transmission System if all the plants in the Portfolio are generating at Bid Capacity, and (ii) the average of the annual peak losses on the Transmission System assuming no EPA is awarded under the CFT. A Capacity Loss for a Portfolio can be either positive or negative, representing an increase or decrease in incremental expected losses, respectively, however no adjustment will be made for a negative Capacity Loss.

A Portfolio may consist of one or more Tenders. A particular Tender may consist of one or more projects. A particular Tender may be part of one or more Portfolios.

4.5 ***<u>Step 5 – Net Portfolio Cost:</u>***

4.5.1 <u>Portfolio Adjustments:</u> Step 3 calculates two Net Tender Costs for each Tender by using the two Electricity Price Forecasts. Two Portfolio costs are determined for each possible Portfolio, using the two Net Tender Costs for each project within the Portfolio. The following Portfolio adjustments are the applied to each Portfolio cost:

- o A credit equal to the VIGP Asset Price, if the Portfolio includes a Tender in respect of which the bidder has made the VIGP Election,

- o A credit equal to the VIGP Salvage Value if the Portfolio does not include a Tender in respect of which the bidder has made the VIGP Election,

- o A debit equal to estimated firm gas transportation costs, if any, inclusive of a 10% contingency allowance, determined in accordance with section 3.4.4.

- o A debit equal to Network Effects, determined in accordance with section 3.3.5.

4.5.2 <u>Averaging Forecast Scenarios:</u> The two adjusted Portfolio costs are then averaged to calculate the Net Portfolio Cost, which is used to determine the recommendation under section 5.

5. **<u>RECOMMENDATION:</u>**

Tenders comprising the Portfolio having the lowest Net Portfolio Cost will be recommended to BC Hydro's senior management and board of directors for award of EPA(s), subject however to the rights of BC Hydro under section 17 of the CFT, as amended by section 11 of Addendum 10.