

VANCOUVER ISLAND – CALL FOR TENDERS

ADDENDUM

Addendum Number: 1
Date of Issue: 14 November 2003
Subject: Quantitative Evaluation Methodology

1. This Addendum is issued pursuant to the BC Hydro Call for Tenders for Capacity and Associated Energy on Vancouver Island, issued 31 October 2003 (the “CFT”).
2. Words and phrases defined in the CFT and used herein have the meanings given in the CFT. Refer to Appendix 1 of the CFT for definitions.
3. Pursuant to section 11.3 of the CFT, this Addendum includes the Quantitative Evaluation Methodology posted herewith.
4. Data assumptions, inputs and sources used in the quantitative evaluation may be revised by BC Hydro by Addendum issued not later than 30 days before the Tender Closing Time. Other CFT amendments may be issued by Addendum not later than 7 days before the Tender Closing Time, as provided in the CFT.

VANCOUVER ISLAND – CALL FOR TENDERS
QUANTITATIVE EVALUATION METHODOLOGY

1. **OVERALL OBJECTIVES:**

1.1 **Background:** The quantitative evaluation methodology is designed to identify the most cost effective method 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 CFT quantitative evaluation methodology, in response to these views of the BCUC.

1.2 **Objectives:** The objective of the quantitative evaluation methodology 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 will be disclosed.
- Questions and answers relative to the CFT, including evaluation issues, will be posted to the website without attribution to particular bidders in accordance with the terms of the CFT.
- Assumptions and other data (e.g. gas and electricity price forecasts) are sourced from reputable, independent agencies, so far as possible.
- Bidders will be 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.
- After consideration of bidder comments, the CFT process, including the quantitative evaluation methodology described herein, will be submitted to the BCUC for its approval.

○ ***Fairness to Bidders:***

- Consistent criteria and evaluation methodology will be applied to every Tender and portfolio of Tenders.

- Upon passing Mandatory Criteria and an acceptable 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 quantitative evaluation 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”), and the Quantitative Evaluation will be carried out by the QEC. These committees are separate and have no overlapping membership, with the QEC privy only to the necessary quantitative data and blind to other data available to the SEC.
- The quantitative evaluation methodology 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, with 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:**

The CFT has been designed to consider a wide range of possible resource options. Bidders have considerable choice in terms of technology, project size, contract term, fuel risk and other project attributes. Accordingly, the quantitative evaluation methodology must also provide for the various permutations and combinations of Tenders that are permitted by the CFT.

A single Tender can be comprised of one or more projects, provided that the Tender does not exceed 300 MW in the aggregate and that each project is at least 25 MW. The quantitative evaluation methodology examines all possible combinations of Tenders (“portfolios”) that aggregate to a minimum of 150 MW and to a maximum of 300 MW. Portfolios may consist of one or more Tenders, and a Tender may be part of one or more portfolios.

The CFT provides significant flexibility on the term of EPAs, allowing bidders to offer a minimum EPA term of 10 years and a maximum term of 25 years. All Tenders are normalized to 25 years in the evaluation methodology and the NPVs of the normalized Tenders are compared on a portfolio basis. The Tender(s) included in the lowest net cost portfolio are recommended for award of EPA(s).

The quantitative evaluation methodology assesses (i) the costs and benefits to BC Hydro of the capacity and associated energy of each Tender, and (ii) certain other impacts of each portfolio on BC Hydro and its ratepayers.

The methodology models 25 years of annual cash flows using Excel spreadsheets that have been developed specifically for this CFT. There are two spreadsheets: a Tender spreadsheet which

computes the Net Tender Cost (section 4.1) for each Tender, and a portfolio spreadsheet which computes the Net Portfolio Cost (section 4.3) for each portfolio.

As described in section 11.3 of the CFT, the assessment of Tenders follows the 6 step process outlined below. The quantitative evaluation methodology 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 May 1, 2007, having regard to project status.

○ **Quantitative Assessment:**

- **Step 3 – Net Tender Cost:** Carried out by the QEC.
- **Step 4 – Portfolio Assembly:** Carried out by the QEC.
- **Step 5 – Net Portfolio Cost:** Carried out by the QEC.

○ **Decision:**

- **Step 6 – Recommendation:** 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 quantitative evaluation are derived from one of three sources:

- the Tender,
- 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 provision for escalation.
- Energy Charge (“EC”) - \$/MWh, with provision for escalation.
- Bid Capacity – MW.
- Capacity Conversion Table - relative % adjustments for temperature and humidity.
- Capacity Degradation Factor - % over the Term.
- Term – in years from 10 to 25.
- Scheduled Planned Outage Allowance Hours:
 - Major Maintenance Years – hours/year.
 - Non-Major Maintenance Years – hours/year.
 - Frequency of Major Maintenance Years.
- For gas-fired tolling plants:
 - Guaranteed Heat Rate at COD at baseload – GJ/GWh Higher Heating Value (“HHV”).
 - Heat Rate Conversion Table - relative % adjustments for temperature and humidity.
 - Heat Rate Degradation Factor - % over the Term.
- For Dispatchable Capacity plants:
 - Start Up Cost (plus Start Up Fuel for gas-fired tolled plants only) for Hot, Warm and Cold Starts in \$ and, if applicable, GJs.
 - Maximum Hot, Warm and Cold Starts/year.
 - Minimum Turndown - %.
 - Guaranteed Heat Rate at COD at Minimum Turndown – GJ/GWh HHV (for gas-fired tolled plants only).

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

3.3.1 **Natural Gas Price Forecasts - General:** The quantitative evaluation methodology will use multiple gas price forecasts or scenarios, including 3 forecasts described in this section. A further alternate gas price forecast sourced from BC Hydro or an independent third party, as

identified in section 3.4, will be included in the selected forecasts. These forecasts will provide a representative range of potential future gas price environments.

The gas price forecasts, together with an Alternate Spark Spread Scenario, will be used in the quantitative evaluation to develop five corresponding electricity price forecasts. These gas and electricity price forecasts and scenarios are used (i) to assess the sensitivity of the portfolios to gas prices, (ii) to model plant dispatch, and (iii) to value energy.

3.3.2 Natural Gas Price Forecasts – Sources:

(a) *Energy Information Administration:*

The Energy Information Administration (“EIA”) of the U.S. Department of Energy annually produces a complete energy forecast, the latest one being reported in Annual Energy Outlook 2003, which was published in December 2002.

EIA’s forecast is for several forms of energy and is linked to an economic outlook that specifies the rate of economic and population growth. The forecast is produced using substantial modeling resources; numerical projections are generated by the National Energy Modeling System (“NEMS”). Interactions between the different energy categories are estimated; prices and quantities are forecast simultaneously for all important energy categories including oil, coal, natural gas, electricity and green energy. The impact of macroeconomic environment and of government regulation and policy is considered.

For long run natural gas prices, a key issue is whether technology and exploration will be able to keep pace with growing demand by finding sufficient supplies and developing them at an economic cost. On this issue EIA's Reference Case position is that exploration and technology will have difficulty keeping up and that, as a consequence, real gas prices for natural gas will rise steadily in the long run.

The EIA Reference Case has U.S. real GDP growing at a rate of 3.0% per year for the period 2005-2025. For the same period population grows at an annual rate of 0.8% and CPI grows at 2.9%. Energy intensity (thousands of BTU per 1996 \$ of GDP) declines at the rate of 1.4% per year.

Natural gas consumption, for the U.S. in the Reference Case, increases at 1.8% per year from 24.60 TCF per year in 2005 to 34.93 TCF per year in 2025. Consumption of natural gas for electricity generation grows at 3.1% per year over the period to 2025.

Imports of natural gas to the U.S. grow at 3.6% per year for 2005-2025. These consist of imports from Canada growing at 2.1% and Liquefied Natural Gas (“LNG”) from outside North America growing at 6.5%. While the LNG growth is higher, it starts from a very small base and remains well below the level of

imports forecast from Canada. The EIA forecast shows new gas supplies from the Mackenzie Delta becoming significant from 2016 onward, with supplies from Alaska coming in 2021.

The world oil price is projected as \$23.27 real 2001 U.S.\$ per bbl. in 2005 and \$26.57 in 2025.

Current market prices for natural gas are higher than the EIA Reference Case projections. However, current high prices may not be sustained and the EIA forecast is based on long run supply, demand and technological considerations. Over the period 2005-2025 the Reference Case forecasts real wellhead natural gas prices in the U.S. to rise at a rate of 1.5% per year. This steady increase reflects an expectation of tightening natural gas supplies relative to demand.

It should be noted that the current Reference Case price outlook is higher than the forecast made in 2002, in turn higher than the 2001 forecast. The upward trend in forecast prices reflects both the gradual extent of change in any large-model forecasting tool, as well as the steady flow of new information showing continued expectations for demand growth but continued softness in supply response.

(b) *National Energy Board:*

The latest long term natural gas forecasts of the National Energy Board of Canada are reported in Canada's Energy Future: Scenarios for Supply and Demand to 2025, July 2003. The previous NEB forecast was issued in 1999. BC Hydro uses the Techno-Vert scenario as one of its selected scenarios.

The main theme of the Techno-Vert scenario is heightened concern for the environment leading to environmentally friendly products and cleaner burning fuels. Customers are willing to pay more for these features and prices of energy are higher. While governments assist with research and development program funding, reliance is primarily placed on market solutions. New technologies increase energy supplies and efficiency of utilization. Productivity is high resulting in high economic growth.

In the Techno-Vert scenario, real Canadian GDP grows at a rate of 2.7% per year for 2001-2025. Energy intensity declines at the rate of 1.7% per year. CPI of Canada grows at 2.0% and Canadian population grows at 0.6%. Energy demand in Canada grows by 1% per year.

Oil price is assumed to be a constant \$22.00 real 2001 U.S. \$ per bbl. for the whole period 2005-2025. This compares with EIA's projection of \$23.27 in 2005 and \$26.57 in 2025.

The NEB Techno-Vert scenario results in higher natural gas demand. The additional demand puts upward pressure on gas prices, which are uniformly higher than the EIA Reference Case in all of the period 2005-2025. Henry Hub

prices in Techno-Vert increase from \$3.53 real 2002 U.S. \$ per MMBtu in 2005 to \$4.06 in 2025 giving an average growth rate of 0.7% per year. The higher prices increase supply from conventional and non-conventional sources of production.

(c) *Confer Consulting Ltd.:*

Confer Consulting Ltd. is a Calgary based consulting firm, which has provided services to BC Hydro since 1981. Confer's forecast is the lowest natural gas price scenario among the base cases of the various price outlooks.¹ Its long run marginal cost of natural gas at Henry Hub increases slowly from \$3.14 real 2002 U.S. \$ per MMBtu in 2005 to \$3.20 in 2025.

The basic analysis performed by Confer is to examine the underlying factors that drive the demand for natural gas in North America, and then assess the supply potential to meet demand at economic prices. The potential supply is assessed by analyses of the long-run marginal cost ("LRMC") of new gas supply; that is, the full cost of investing in and operating new gas supply through its economic life. Several supply sources and technologies are assessed. Strong demand growth expectations for natural gas cause the need to examine the long-run marginal costs of supply from remote areas, such as the Mackenzie Delta; non-conventional technology, such as coalbed methane; and imports of LNG.

The lower level of Confer's price forecast as compared with EIA is due to Confer's view that demand in North American for natural gas will be lower than forecast by the EIA and that improvements in technology will continue and lower the cost of new gas supply below that forecast by the EIA. Confer states that:

"...reliance on improvements in technology and on demand responses to higher prices result in real future increases in LRMC at modest levels...The challenge in forecasting the longer-term future path of LRMC focuses on the balance between technology and resource location and condition. By forecasting ever-increasing real prices to the end of its forecast outlook in 2025, the Annual Energy Outlook ("AEO") of the EIA concludes that there will not be equilibrium between these forces in the future and that the increase in costs of resource location and condition will, from now on, be such that the benefits of technology improvements will fail to mitigate real price increases. On the other hand, Confer's outlook, and those of other parties that do not have as steep a price increase as the AEO, is based on a more stable balance between these two forces."

Confer points out that in the EIA Reference Case, a large fraction of incremental gas supply comes from the Western U.S. where costs have higher historical levels,

¹ Confer Consulting Ltd.'s most recent forecast was presented to BC Hydro on December 12, 2002.

but where supply has increased significantly in the past several years. Confer sees significant supplies from LNG and Mackenzie Delta becoming available sooner than the EIA at costs that are higher than historical supply costs but still economic. Confer forecasts that the Mackenzie pipeline may be built by 2009 and new Alaskan supply some time well after 2012, whereas EIA indicates 2016 for Mackenzie and 2021 for Alaska. Confer notes that LNG imports have become economic and can be expected to increase supply. Confer estimates the LRMC of Mackenzie gas delivered to AECO/NIT to be in the range \$2.15 to \$2.35 U.S. \$ per MMBtu. This would correspond to a Henry Hub price of \$3.00 or less, all based on a US\$0.64 = Cdn\$1.00 exchange rate. Confer also stresses that sustained high gas prices will lead to significant demand destruction. The EIA outlook may underestimate this demand effect.

3.3.3 Natural Gas Forecast Basis Differentials: All the gas price forecasts described above are 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. Accordingly, the gas prices in the forecasts will be adjusted to account for the basis differential between Henry Hub and Sumas. The Henry Hub to Sumas differential being used in the evaluation methodology 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. The differential is common to all natural gas price scenarios.

3.3.4 Natural Gas Forecast and Basis Differential Updates: BC Hydro expects that gas price scenarios will be revised by the publishing agencies. Accordingly, BC Hydro expects to issue updated gas price forecasts and basis differential determinations when the revisions are published. New versions of the evaluation spreadsheet tools will be made available to bidders at that time.

3.3.5 Natural Gas Forecast Periods: The publicly available forecasts have terms of 20 years. Since the CFT is evaluating bids of up to 25 years from 2007, the forecasts are escalated yearly as per the trend (calculated as the annual compounded rate of increase) over the forecast period.

3.3.6 Network Upgrade Costs: As outlined in section 7 of the CFT, BC Hydro will bear Network Upgrade Costs, whether triggered by interconnection or take-away transmission associated with Tenders and portfolios. However, these costs will be reflected in the quantitative evaluation. Network Upgrade Costs will be determined by BCTC in its interconnection and transmission service studies.

3.4 **Data Sourced from BC Hydro:**

3.4.1 Electricity Price Forecasts - General: Five electricity price forecasts are used. Each forecast corresponds to a gas price forecast.

Electricity price forecasts will be updated for use in the quantitative evaluation to reflect any revised gas price forecasts.

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

3.4.2 Electricity Price Forecasts – Data: Each electricity price forecast reflects prices at Heavy Load Hours (“HLH”) and Light Load Hours (“LLH”) with monthly resolution. Each forecast comprises two components:

(a) *Years 2007 to 2012:* Electricity prices at the BC - US border are based on a forecast of supply and demand for electricity and cost drivers expected to prevail, and are modeled under a computer simulation of the hourly supply-demand balance for the Western Electricity Coordinating Council (“WECC”) which includes the Western US states, BC and Alberta. BC Hydro uses the Henwood Energy Services simulation software, using certain inputs based on BC Hydro’s knowledge and system, which among other modeling details outlined below, accounts for transmission costs and limitations. The price of the marginal resource at the point where supply and demand are in equilibrium determines the price for that hour. Monthly and yearly 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%)
- Expected hourly load shape (estimated from hourly 1993 - 2000 loads)
- Expected BC Hydro electricity load forecast and resource plan
- Forecast natural gas prices
- 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
- Expected long term transmission limits, losses and costs

(b) *Year 2013 and Beyond:* Prices are set equal to the estimated unit cost of the most economical resource addition, currently a natural gas-fired Combined Cycle Gas Turbine (“CCGT”). Capital and operating costs are based primarily on third party sources. Key costing details (all \$ in 2000 real \$) include:

- Greenfield project (a new project, not a re-powering of an existing facility), located in the Lower Mainland
- 262 MW (average over life) F-series Combined Cycle Gas Turbine (CCGT)
- Capital Cost = U.S. \$200 million
- Variable O & M cost = 3.15 US\$/MWh
- Fixed O & M cost = 2.15 US\$/MWh
- Forecast natural gas prices
- Fuel tax = 7%
- Heat Rate = 6863 MMBtu/MWh HHV, average over life

- Unit average availability = 91.3%
- Project life = 25 years

3.4.3 Alternative Spark Spread Scenario: The quantitative evaluation will also consider a scenario in which the relationship between gas and electricity prices is based on an implied heat rate that is lower than the other forecasts. The purpose of this scenario is to factor in the sensitivity of the portfolios being assessed to the potential for unforeseen improvements in technology or extraordinary market conditions that might stress the expected relationship between gas and electricity prices.

3.4.4 Alternative Gas Price Forecast: BC Hydro will develop, or source from an independent third party, a further gas price forecast to ensure that the gas and electricity price forecasts used in the evaluation will be truly representative of an appropriate range of market scenarios, including high gas price environments. Details of this forecast will be issued by Addendum.

3.4.5 Gas Transportation Costs: Gas transportation costs from Sumas to generator locations on Vancouver Island will be determined by BC Hydro not later than 30 days before the Tender Closing Time, based on discussions with Terasen and/or any regulatory proceedings relative to gas transportation agreements, rates and/or rate designs. The purpose of these discussions is to ascertain the most cost effective gas transportation solutions to support any tolling obligations that BC Hydro may assume as a result of the outcome of the CFT process. Solutions may involve utilization of GSX and/or upgrades on the Terasen system and the costs used may reflect a long-term fixed rate(s) or an estimated cost of service rate or alternative rate structure, depending on the outcome or status of the discussions and/or proceedings. The estimated gas transportation cost will be expressed as the NPV of the estimated stream of gas transportation charges.

3.4.6 Dispatchable Plants – Number of Starts per Year: For dispatchable plants, the quantitative evaluation model will calculate the NPV of the Start Up Payments for each Tender as part of the determination of the Net Tender Cost. In order to determine the annual Start Up Payments, it is necessary to estimate the number of starts expected to occur per year for each dispatchable plant. BC Hydro will establish the expected number of starts per year for generic dispatchable plants having different assumed heat rates, for each gas price forecast, and publish the results in a table before the Tender Closing Time. The quantitative evaluation model will assume a fixed number of starts per year, based on the table, using the information provided in the Tender.

3.4.7 Currency Exchange Rate: The evaluation is performed in Canadian dollars. Bidders must provide Tender information in \$Cdn. Original natural gas and electricity price forecasts are in \$U.S. These will be converted to \$Cdn using forward market exchange rates. BC Hydro may update the forward market exchange rates before the Tender Closing Time.

3.4.8 Transmission Deferral Credit: Incremental Dependable Capacity above the 150 MW minimum portfolio size will be credited with a transmission deferral credit, based on the deferral of construction of the 230 kV cables to Vancouver Island, currently scheduled to commence service in 2009. The deferral period is based on the forecast electricity load growth for Vancouver Island of 15 MW per year. This forecast will be included in the BC Hydro Revenue

Requirements application to be filed with the BCUC in December, 2003. The maximum deferral that can be realized is 10 years.

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

3.4.10 Inflation: The evaluation methodology relies on the British Columbia government's official inflation forecast for the term of the forecast and thereafter inflation escalates yearly as per the trend (calculated as the annual compounded rate of increase) over the forecast period.

3.4.11 VIGP Asset Price Credit: Portfolios including VIGP are credited with \$50 million, which is the price payable to BC Hydro for the bidder's acquisition of the VIGP Development Assets. BC Hydro has determined this amount based on its assessment of the value of VIGP development work done to date, assuming issue of material permits before the Tender Closing Time.

3.4.12 VIGP Asset Salvage Value: Portfolios which do not include VIGP are credited with BC Hydro's estimate (currently \$20 million) of the net realizable value of VIGP Development Assets, assuming that VIGP is not constructed.

4. **APPLYING THE DATA:**

4.1 **Step 3 – Net Tender Cost:**

4.1.1 Formula: 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 Payments

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

4.1.2 Capital Charges and Operation & Maintenance Charges: 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 and the Capacity Degradation Factor.

- CC Payment is a monthly charge paid to the Seller under the EPA, based on the Bid Capacity (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 Bid Capacity (adjusted for the Capacity Degradation Factor). This charge may be subject to escalation.

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

The Bid Capacity will be adjusted based on the values in the tendered Capacity Conversion Table, by calculating the expected capacity given a probability distribution for humidity and temperature to be provided by BC Hydro.

4.1.3 Energy Margin: The Energy Margin is determined for each Tender under each of the 5 alternative gas and corresponding electricity price forecasts and scenarios. The dispatch pattern of each plant is modeled, and may change, based on the forecast or scenario used.

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 EPA term. This factor will be interpolated over the EPA term and applied in determining heat rate used in calculating the Energy Margin.

The tendered heat rate(s) will be adjusted based on the values in the tendered Heat Rate Conversion Table, by calculating the expected heat rate given a probability distribution for humidity and temperature to be provided by BC Hydro.

Calculating the Energy Margin:

For all plants:

Energy Margin = Hours in dispatch-on period x (forecast electricity market price – Tender Variable Cost) x Bid Capacity (or Bid Capacity x Minimum Turndown, as applicable) adjusted for the Capacity Degradation Factor.

The quantitative evaluation determines the Tender Variable Cost as follows:

- For non-tolling Must-Run Capacity or non-tolling Dispatchable Capacity plants:
 - Tender Variable Cost = Energy Charge, adjusted for escalation.
- For gas-fired tolling Dispatchable Capacity plants:
 - Weighted Average Tender Variable Cost = Energy Charge, adjusted for escalation, plus the cost of the gas commodity multiplied by the weighted average of the heat rate at baseload and the heat rate at Minimum Turndown.
- For gas-fired tolling Must-Run Capacity plants:
 - Tender Variable Cost = Energy Charge, adjusted for escalation, plus the gas commodity costs multiplied by heat rate.

Dispatch Modeling:

- (a) *Must-Run Capacity Plants:* For a Must-Run Capacity plant, the spreadsheet does not model an economic dispatch. Instead it assumes that the 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. In those periods when the Tender Variable Cost is higher than the forecast market price, the margin will be negative. In periods when the Tender Variable Cost is lower than the forecast market price, the margin will be positive. The NPV of the net margin will be used to determine the NPV of the Energy Margin.
- (b) *Dispatchable Capacity Peaking Plants:* For a Dispatchable Capacity peaking plant, the evaluation models a simplified dispatch to estimate the net benefits from BC Hydro being able to purchase electricity from the tendered plant, rather than from electricity markets. The evaluation model will dispatch the plant if the Tender Variable Cost is less than the forecast electricity market price. This comparison is performed for 24 periods each year (12 months, and HLH and LLH periods in each month).
- (c) *Dispatchable Capacity Non-Peaking Plants:* For Dispatchable Capacity plants other than peaking plants:
- If the Tender Variable Cost is lower than both the LLH and HLH forecast market price in any month, the evaluation will dispatch the plant for that month at baseload.
 - If the Tender Variable Cost is higher than the LLH forecast market price but lower than the HLH forecast market price, the evaluation will:
 - Compare the Weighted Average Tender Variable Cost assuming Minimum Turndown in LLH to the weighted average of the HLH and LLH market price for such energy, assuming that the plant is operated at Minimum Turndown for the LLH of that month,
 - If the Weighted Average Tender Variable Cost is higher than the weighted average market price, then the evaluation assumes that the plant will not be operated during such month,
 - If the Weighted Average Tender Variable Cost is lower than the weighted average market price, then the evaluation estimates the net benefit from BC Hydro being able to purchase electricity from the tendered plant operating at full output during HLH and at Minimum Turndown during LLH, rather than from the market.
 - If the Tender Variable Cost is higher than both the LLH and HLH forecast price in any month, the evaluation will not dispatch the plant for that month.

Start Up Costs:

Start Up Costs are calculated differently for tolling and non-tolling Tenders.

- Tolling Tenders: Start Up Costs are the costs of fuel purchases needed for start-ups (tendered SUF x forecast gas price x number of starts per year), plus the fixed start-up payments (tendered SUC x number of starts per year). For purposes of this calculation, tendered SUFs and SUCs for hot, warm and cold starts will be averaged into one SUF and SUC, respectively. The tendered heat rate will be used to estimate the number of starts per year from a table provided by BC Hydro.
- Non-Tolling Tenders: Start Up Costs are the costs of the fixed start-up payments (tendered SUC x number of starts per year). The model will impute a heat rate based on the ratio of the tendered Energy Charge to the gas price forecast. The imputed heat rate will be used to estimate the number of starts per year from a table provided by BC Hydro.

For Must-Run Capacity plants, the methodology specifies that Start Up Costs will be \$0.

If the average of the tendered MSYs (maximum starts per year) for hot, warm and cold starts is less than 130% of the estimated number of starts per year as determined by the table, then the model will assume that the tendered project is a must-run project.

4.2 Step 4 – Portfolio Assembly:

All possible portfolios of Tenders that will deliver not less than 150 MW and not more than 300 MW of capacity are assembled.

- 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.
- Where a bidder quotes alternate prices for the same project as permitted under the CFT, then each tendered price for that project is treated as a separate but mutually exclusive Tender for purposes of portfolio assembly.

4.3 Step 5 – Net Portfolio Cost:

4.3.1 Portfolio Adjustments: For each possible portfolio, a Net Portfolio Cost is determined for each of the five gas and corresponding electricity price forecasts and scenarios. The Net Portfolio Cost is the Net Tender Cost for each Tender in the portfolio with the following adjustments:

- Transmission Deferral credit, if applicable, depending on the aggregate portfolio capacity,

- VIGP Development Assets credit, if the portfolio includes VIGP,
- VIGP Development Assets salvage value, if the portfolio does not include VIGP,
- Gas transportation costs borne by BC Hydro for any gas-fired tolling plants included in the portfolio, taking into account any consequential incremental costs or cost savings to BC Hydro in providing gas transportation service to the Island Cogeneration Project at Elk Falls on Vancouver Island, and
- Network Upgrade Costs to be borne by BC Hydro in respect of all Tenders in the portfolio.

4.3.2 Averaging Alternate Forecast Scenarios: The Net Portfolio Cost for each portfolio is the equally weighted average of each alternate portfolio cost determined under section 4.3.1.

5. **DECISION:**

Tenders comprising the portfolio having the lowest Net Portfolio Cost determined in section 4.3.2 will be recommended to BC Hydro's senior management and Board of Directors for award of EPA(s).