1.0 Reference: Report on the CFT Process, page 12

"The network upgrade costs were provided by the BCTC whereas the gas transportation costs were supplied by TGVI and compared to the transportation costs associated with the GSX pipeline option. TGVI costs were used in the final analysis because they were lower than the estimated GSX toll".

1.1.1 Please confirm that as outlined above, the use of the lower TGVI estimates resulted in a more cost effective tier 1 proposal than might otherwise have been the case. If not, why not?

RESPONSE:

The firm gas tolls associated with GSX were higher than those supplied by TGVI. As all portfolios evaluated by the QEM involved a VIGP option, the impact on the Net Portfolio Costs was common to all and the DPP project would still have been selected.

In terms of the Cost Effectiveness Analysis in Appendix J, the use of the GSX estimate for the firm gas tolls instead of the TGVI estimate would have made the Tier 1 outcome relatively less attractive.

1.0 Reference: Report on the CFT Process, page 12

"The network upgrade costs were provided by the BCTC whereas the gas transportation costs were supplied by TGVI and compared to the transportation costs associated with the GSX pipeline option. TGVI costs were used in the final analysis because they were lower than the estimated GSX toll".

1.1.2 Given that regulatory approval for the GSX pipeline project is contingent on approval of VIGP, would this GSX approval also flow from an EPA for Duke Point Power?

RESPONSE:

This Information Request is out of scope.

1.0 Reference: Report on the CFT Process, page 12

"The network upgrade costs were provided by the BCTC whereas the gas transportation costs were supplied by TGVI and compared to the transportation costs associated with the GSX pipeline option. TGVI costs were used in the final analysis because they were lower than the estimated GSX toll".

1.1.3 If TGVI is confirmed as the fuel source for DPP, what penalties or other costs will be incurred by BC Hydro under its contractual arrangements with GSX PL? How would BC Hydro recover those costs?

RESPONSE:

This Information Request is out of scope.

1.0 Reference: Report on the CFT Process, page 12

"The network upgrade costs were provided by the BCTC whereas the gas transportation costs were supplied by TGVI and compared to the transportation costs associated with the GSX pipeline option. TGVI costs were used in the final analysis because they were lower than the estimated GSX toll".

1.1.4 Were any of the costs pertaining to GSX considered while evaluating the CFT proposals, with regard to the cost effectiveness for BC Hydro and its ratepayers? If so, please summarise. If not, why not?

RESPONSE:

This Information Request is out of scope.

1.0 Reference: Report on the CFT Process, page 12

"The network upgrade costs were provided by the BCTC whereas the gas transportation costs were supplied by TGVI and compared to the transportation costs associated with the GSX pipeline option. TGVI costs were used in the final analysis because they were lower than the estimated GSX toll".

1.1.5 If TGVI were not confirmed as a fuel source for DPP, how would this affect the validity of the CFT outcomes as currently projected?

RESPONSE:

TGVI is not the "fuel source" for Duke Point. Rather, gas would be transported to Duke Point via the TGVI high pressure transmission pipeline system or by other means (see BC Hydro's responses to BCUC IR 2.47.9 and Gold River IR 1.3.1 for further discussion).

2.0 Reference: Report on the CFT Process, page 17 and Appendix J

"The common assumptions used for the analysis of CFT cost effectiveness are as follows:

- 230 kV transmission cable in service after March 2009
- Mainland generation – electricity price same as Tier 1 CFT result"

1.2.1 Page 15 of the CFT Report refers to a 2008 in service date for the 230 kV cables. What effect would that date (2008) have on the cost-effectiveness forecasts as outlined in Attachment A of Appendix J?

RESPONSE:

Attachment A of Appendix J considers various in-service dates for the 230 kV transmission circuit, from F2009 to F2014. The October 2008 in-service date referred to in the question corresponds to the F2009 in-service scenario in Attachment A.

2.0 Reference: Report on the CFT Process, page 17 and Appendix J

"The common assumptions used for the analysis of CFT cost effectiveness are as follows:

- 230 kV transmission cable in service after March 2009
- Mainland generation – electricity price same as Tier 1 CFT result"

1.2.2 If an in service date of 2008 is possible, why were only later dates used?

RESPONSE:

Please see the response to McLennan IR 1.2.1.

3.0 Reference: Appendix J, page 2

"In both the Tier 2 and 'No Award' scenarios, the energy backfill was assumed to come from new mainland generation at two price scenarios: 100% and 90% of the unit price of the Tier 1 project on VI but without the associated firm gas tolls in both cases."

"Neither Tier 1 nor Tier 2 resulted in any deferral of the 230 kV cable."

"For the purposes of this analysis, the base case assumptions were considered to be: 261 MW load requirement for fiscal 07/08; EIA electricity price forecast; pricing for mainland generation same as Tier 1 price i.e. VI 250 MW CCGT) excluding gas tolls; one year delay in the cable (i.e. 2010 in-service)."

1.3.1 Why were different assumptions made with regard to pricing for the tier 1, tier 2 and 'no award' options? Why was 90% chosen as an alternative?

RESPONSE:

The costs in each portfolio were the costs specific to the resource in that portfolio. The *cost* of Mainland generation in the "No Award" case (approximately 1800 GWh/year) and in the "Tier 2" case (approximately 600 GWh/year) was based on the cost of the Tier 1 project excluding tolls. In all three cases the *value* of the annual energy was calculated based on the EIA price forecast. For each portfolio, the present value of annual costs was calculated net of the value of the annual energy based on the EIA market price. 90% of the Tier 1 cost was chosen as a conservative scenario to test the 100% cost assumption.

3.0 Reference: Appendix J, page 2

"In both the Tier 2 and 'No Award' scenarios, the energy backfill was assumed to come from new mainland generation at two price scenarios: 100% and 90% of the unit price of the Tier 1 project on VI but without the associated firm gas tolls in both cases."

"Neither Tier 1 nor Tier 2 resulted in any deferral of the 230 kV cable."

"For the purposes of this analysis, the base case assumptions were considered to be: 261 MW load requirement for fiscal 07/08; EIA electricity price forecast; pricing for mainland generation same as Tier 1 price i.e. VI 250 MW CCGT) excluding gas tolls; one year delay in the cable (i.e. 2010 in-service)."

1.3.2 Why does the base case assume a (one year delay) 2010 in-service date for the 230 kV cables? Please reconcile this with the statement that Tier 1 did not result in any deferral of the cable.

RESPONSE:

The statement "Neither Tier 1 nor Tier 2 resulted in any deferral of the 230 kV cable." refers to the fact that no transmission deferral credit was used in the QEM.

4.0 Reference: Appendix J, page 2

"Neither Tier 1 nor Tier 2 resulted in any deferral of the 230 kV cable. However both were credited with deferral of the next 230 kV cable: from 2020 to 2026 in the case of Tier 1, and from 2020 to 2023 in the case of Tier 2."

1.4.1 What credit was applied to these options for deferral of the next 230 kV cable?

RESPONSE:

The Tier 1 portfolio was given an credit of $20 million for deferring the cost of the second 230 kV AC cable to year 2026 relative to it being required in 2020 in the "No Award" case. The Tier 2 portfolio was given a credit of $11 million for deferring the cost of the second 230 kV cable to 2023 compared to the "No Award" case. This was based on an estimated cost of $172 million 2004 dollars (including overhead and interest during construction) for that cable. These dates for the 23 kV cables were based on the October 2004 Load Forecast and included an allowance of 80 MW for future new Vancouver Island dependable capacity resources that might be available in time to contribute to deferring the second cable.

4.0 Reference: Appendix J, page 2

"Neither Tier 1 nor Tier 2 resulted in any deferral of the 230 kV cable. However both were credited with deferral of the next 230 kV cable: from 2020 to 2026 in the case of Tier 1, and from 2020 to 2023 in the case of Tier 2."

1.4.2 How is this statement reconciled with the removal of a transmission deferral credit from the CFT evaluation process, as outlined on page 7 of the CFT Report?

RESPONSE:

The referenced statement relates to the cost-effectiveness analysis done at the request of BC Hydro's senior management as part of its due diligence regarding the CFT outcome. For CFT purposes, no transmission deferral credit was included in the Quantitative Evaluation Methodology and the determination of the least cost portfolio.

5.0 Reference: CFT Report, page 18

"The relative cost benefit of the Tier 1 option increases as the in-service date of the transmission cable is delayed."

"Overall, from a purely quantitative standpoint, Tier 1 shows the lowest cost to ratepayers, especially when taking the uncertainty of the 230 kV installation into consideration."

1.5.1 What uncertainty does this statement refer to? Does uncertainty exist over actual installation of the cable, or just the timing?

RESPONSE:

Please see the response to BCUC IR 1.29.3.

5.0 Reference: CFT Report, page 18

"The relative cost benefit of the Tier 1 option increases as the in-service date of the transmission cable is delayed."

"Overall, from a purely quantitative standpoint, Tier 1 shows the lowest cost to ratepayers, especially when taking the uncertainty of the 230 kV installation into consideration."

1.5.2 Could the relative cost benefit of a delay in the 230 kV cable (for Tier 1) affect the planned in service date? Why?

RESPONSE:

No, because even though the CFT Tier 1 outcome resulted in 252 MW of new generation capacity on Vancouver Island, the 230 kV transmission circuit still needs to be installed as soon as possible (October 2008 being the earliest possible date) to reliably meet the load requirements under an N-1 system condition. Even with the 230 kV circuit in-service by October 2008, there is still a projected Island load deficit of 10 MW for F2008.

5.0 Reference: CFT Report, page 18

"The relative cost benefit of the Tier 1 option increases as the in-service date of the transmission cable is delayed."

"Overall, from a purely quantitative standpoint, Tier 1 shows the lowest cost to ratepayers, especially when taking the uncertainty of the 230 kV installation into consideration."

1.5.3 What is the relative cost benefit for other options of expediting the 230 kV cable in-service date? Was this possibility considered when evaluating cost effectiveness? If not, why not?

RESPONSE:

The Cost-Effectiveness Analysis had scenarios that included the earliest possible in-service date for the 230 kV transmission circuit. Please see the response to JIESC 1.8(a).

6.0 Reference: CFT Report, page 18

"However, the "No Award" scenario provides lower costs based on the sensitivities for higher gas prices and lower Mainland generation costs".

1.6.1 Are higher gas prices and lower Mainland generation costs considered unlikely? Why?

RESPONSE:

The forecasts used in the Quantitative Evaluation (QEM) represented BC Hydro's best estimate of future natural gas prices and Mainland generation costs at the time of the evaluation. The additional scenarios in Appendix J of the CFT report represent specific stress tests that are less likely than the scenarios used in the QEM.

6.0 Reference: CFT Report, page 18

"However, the "No Award" scenario provides lower costs based on the sensitivities for higher gas prices and lower Mainland generation costs".

1.6.2 If higher gas prices are considered unlikely, please reconcile this with the statement in Reference 8 below.

RESPONSE:

BC Hydro expects that on average, over the long-term, there is an equal probability of actual gas prices being above the forecasts used in the QEM and below the forecasts used in the QEM.

6.0 Reference: CFT Report, page 18

"However, the "No Award" scenario provides lower costs based on the sensitivities for higher gas prices and lower Mainland generation costs".

1.6.3 If higher gas prices are considered likely, please explain why the no award options which show the lowest cost in the immediate term (as outlined in Appendix J, Attachment A) were not deemed the most cost effective solution.

RESPONSE:

The High Gas – Low Electricity forecast scenario in Attachment A of Appendix J is not considered likely.

7.0 Reference: Reference Appendix J, page 3

"If, in the base case scenario, the pricing for mainland generation is 10% lower than the Tier 1 price, the Tier 1 outcome shows a savings of $21 million over the Tier 2 outcome, and a premium of $47 million over the "No Award" case. If, in the base case scenario, the High Gas Low Electricity forecast is substituted for the EIA electricity price forecast, the Tier 1 outcome shows a savings of $2 million over the Tier 2 outcome, and a premium of $33 million over the "No Award" case. Both of these alternates are considered stress tests of the base case scenario."

1.7.1 Please clarify whether 'Low Electricity' refers to demand, or cost, and how this is linked to the 'High Gas' forecast.

RESPONSE:

The High Gas – Low Electricity forecast scenario was constructed by taking the EIA gas forecast and the two corresponding electricity price forecasts (i.e. full recovery and partial recovery) used in the QEM, and replacing the EIA gas forecast with an artificially derived high gas price forecast but keeping the two electricity price forecasts the same as those used in the QEM. The result is a gas price that is disconnected to the electricity forecast, hence the name "High Gas – Low Electricity".

Please also see the response to BCUC IR 1.14.6.

7.0 Reference: Reference Appendix J, page 3

"If, in the base case scenario, the pricing for mainland generation is 10% lower than the Tier 1 price, the Tier 1 outcome shows a savings of $21 million over the Tier 2 outcome, and a premium of $47 million over the "No Award" case. If, in the base case scenario, the High Gas Low Electricity forecast is substituted for the EIA electricity price forecast, the Tier 1 outcome shows a savings of $2 million over the Tier 2 outcome, and a premium of $33 million over the "No Award" case. Both of these alternates are considered stress tests of the base case scenario."

1.7.2 Please explain and justify the statement that these are considered stress tests of the base case scenario.

RESPONSE:

Please see the response to McLennan IR 1.3.1 for the first alternative (the 10% lower pricing assumption for Mainland generation).

Please see the response to McLennan IR 1.7.1 for the second alternative (the High Gas – Low Electricity scenario).

7.0 Reference: Reference Appendix J, page 3

"If, in the base case scenario, the pricing for mainland generation is 10% lower than the Tier 1 price, the Tier 1 outcome shows a savings of $21 million over the Tier 2 outcome, and a premium of $47 million over the "No Award" case. If, in the base case scenario, the High Gas Low Electricity forecast is substituted for the EIA electricity price forecast, the Tier 1 outcome shows a savings of $2 million over the Tier 2 outcome, and a premium of $33 million over the "No Award" case. Both of these alternates are considered stress tests of the base case scenario."

1.7.3 Was any forecast done with a High Gas – High Electricity scenario? If yes, how did this affect the results in Attachment A? If not, why not?

RESPONSE:

There was no High Gas – High Electricity scenario. Please refer to BC Hydro's response to GSXCCC IR 1.24.1.

8.0 Reference: Appendix I, page 47

"However, natural gas prices are projected to be higher for Vancouver Island compared to the Mainland over the entire forecast period".

1.8.1 What forecast period does this statement reference?

RESPONSE:

The period referred to is the 25-year forecast horizon used in the QEM (2007 – 2032).

8.0 Reference: Appendix I, page 47

"However, natural gas prices are projected to be higher for Vancouver Island compared to the Mainland over the entire forecast period".

1.8.2 Given this statement, what impact on electricity prices from thermal generation on Vancouver Island can be anticipated? Would this affect only customers on Vancouver Island, or BC overall?

RESPONSE:

The cost of BC Hydro serving Vancouver Island customers will be rolled into BC Hydro's general revenue requirements. Under BC Hydro's rate design principles, this cost will be borne by all of its customers.

Please refer to the CFT report for a discussion of customer rate impacts.

9.0 Reference: Appendix I, (Load Forecast) pages 48 and 50

"The reasons for slowing growth rates for energy sales include the impact of the rate increase, a slowing of forecast penetration of energy using appliances as well as the anticipated slowing of the penetration of electric space heating."

"The main reason for the decline in use rate in the near term, and the slower growth in use rate over the longer term, is assumption of the load impact associated with the 8.9% increase in electricity rates applied in 2004."

1.9.1 If high gas prices on Vancouver Island were to result in higher electricity rates, presumably the same factors would continue to apply. Is this correct?

RESPONSE:

It is not expected that gas-fired generation on Vancouver Island will alter the price of natural gas for Vancouver Island consumers. Please see BC Hydro's response to McLennan IR 1.8.2 regarding potential electricity rate impacts.

9.0 Reference: Appendix I, (Load Forecast) pages 48 and 50

"The reasons for slowing growth rates for energy sales include the impact of the rate increase, a slowing of forecast penetration of energy using appliances as well as the anticipated slowing of the penetration of electric space heating."

"The main reason for the decline in use rate in the near term, and the slower growth in use rate over the longer term, is assumption of the load impact associated with the 8.9% increase in electricity rates applied in 2004."

1.9.2 Do current energy demand projections include the impact of high electricity prices on Vancouver Island?

1.9.3 If yes, where is this reflected in the comparison of options and their cost-effectiveness?

RESPONSE:

1.9.2

The revised Electricity Load Forecast for 2004 includes the impact of BC Hydro's recently approved rate increase of 4.85%.

1.9.3

The load forecast referenced in response to McLennan IR 1.9.2 was used in the Cost Effectiveness Analysis to determine the volume of bridging capacity required in each outcome before the 230 kV transmission circuit comes into service, and to determine the timing of the second 230 kV transmission circuit.

10.0 Reference: CFT Report, page 18

"The relative cost benefit of the Tier 1 option increases as the in-service date of the transmission cable is delayed. The relative cost benefit of the Tier 1 option increases as the in-service date of the transmission cable is delayed. Consequently, because of its size and economies of scale, Tier 1 is the CFT outcome most capable of mitigating any delay in the 230 kV cable."

"For the Demand Management proposal, the need to negotiate a suitable curtailment arrangement with Norske Canada carries uncertainty relative to the outcome of the CFT process with its legally binding bids and fixed prices".

1.10.1 Please explain and expand on the reference to 'fixed prices'.

RESPONSE:

The reference to 'fixed prices' has to do with the fact that in a CFT, the tendered pricing is firm and legally binding. Thus, upon BC Hydro's acceptance of a CFT bid, the electricity pricing contained therein cannot be retracted or renegotiated.

10.0 Reference: CFT Report, page 18

"The relative cost benefit of the Tier 1 option increases as the in-service date of the transmission cable is delayed. The relative cost benefit of the Tier 1 option increases as the in-service date of the transmission cable is delayed. Consequently, because of its size and economies of scale, Tier 1 is the CFT outcome most capable of mitigating any delay in the 230 kV cable."

"For the Demand Management proposal, the need to negotiate a suitable curtailment arrangement with Norske Canada carries uncertainty relative to the outcome of the CFT process with its legally binding bids and fixed prices".

1.10.2 Given the specifics contained in the NCDMP proposal submitted to the BCUC in September 2004, in relation to project number 3698376, what 'uncertainty' remains with regard to this option?

RESPONSE:

There are still uncertainties regarding timing, cost and contractual arrangements. Please see the response to BCUC IR 1.40.2.

10.0 Reference: CFT Report, page 18

"The relative cost benefit of the Tier 1 option increases as the in-service date of the transmission cable is delayed. The relative cost benefit of the Tier 1 option increases as the in-service date of the transmission cable is delayed. Consequently, because of its size and economies of scale, Tier 1 is the CFT outcome most capable of mitigating any delay in the 230 kV cable."

"For the Demand Management proposal, the need to negotiate a suitable curtailment arrangement with Norske Canada carries uncertainty relative to the outcome of the CFT process with its legally binding bids and fixed prices".

1.10.3 To what extent would the NCDMP option mitigate uncertainty over installation of the 230 kV cables?

RESPONSE:

The NCDMP does not mitigate the uncertainty over the installation of the 230 kV transmission circuit, but does reduce reliance on temporary generators to bridge shortfalls in capacity before the 230 kV transmission circuit comes into service. This benefit has been reflected in Appendix J, Cost Effectiveness Analysis.

Refer to response to BCUC IR 1.29.3.

11.0 Reference: CFT Report, page 1

"In particular, dependable capacity must be in place by 2007 to offset the fact that the high voltage direct current (HDVC) transmission system will no longer be able to reliably supply Vancouver Island from the mainland of the province."

1.11.1 Would the NCDMP option, if implemented, provide dependable capacity?

RESPONSE:

Please see the responses to BCUC IRs 1.38.0 and 1.40.2.

12.0 Reference: CFT Report, pages 15, 17, and page 18 (reference 10 above)

"This outlook indicates that 252 MW of capacity purchased in the CFT is not sufficient to meet the load requirement in fiscal 2007/2008. The gap increases further if the construction of the proposed 230 kV transmission circuit is delayed beyond the October 2008 earliest in-service date."

"Based on the most recent load forecast and supply outlook, the system was assumed to require additional energy starting in 2010. The total volume of new energy supply being added to the system under each of the three CFT outcomes was based on the energy contribution from the Tier 1 plant…"

1.12.1 Please reconcile these two statements: if the CFT outcome is not sufficient for fiscal 2007/2008, why is additional energy not required until 2010?

RESPONSE:

The first statement refers to a capacity deficit on Vancouver Island. The second statement refers to an energy deficit on the BC Hydro system.

12.0 Reference: CFT Report, pages 15, 17, and page 18 (reference 10 above)

"This outlook indicates that 252 MW of capacity purchased in the CFT is not sufficient to meet the load requirement in fiscal 2007/2008. The gap increases further if the construction of the proposed 230 kV transmission circuit is delayed beyond the October 2008 earliest in-service date."

"Based on the most recent load forecast and supply outlook, the system was assumed to require additional energy starting in 2010. The total volume of new energy supply being added to the system under each of the three CFT outcomes was based on the energy contribution from the Tier 1 plant…"

1.12.2 If the Tier 1 capacity outcome is not sufficient by 2008, and the gap increases thereafter, please justify the statement that Tier 1 is the CFT outcome most capable of mitigating any delay in the 230 kV cable.

RESPONSE:

The reason that the Tier 1 outcome is most capable of mitigating delays in the 230 kV transmission circuit is that the capacity shortfall in 2008 associated with either of the other two outcomes is significantly greater than the capacity shortfall in 2008 associated with the Tier 1 outcome.

13.0 Reference: CFT Report, page 16

"The best outcome is the one that results in the lowest NPV cost to BC Hydro and its ratepayers on a risk-adjusted basis i.e. recognizes cost and time certainty."

1.13.1 Given the estimate of a 2004 date for implementation of the NCDMP, and its apparent cost effectiveness, please explain why a combination of this alternative and the earliest in-service date for the 230 kV cables is not the best outcome.

RESPONSE:

BC Hydro is seeking a reliable, date certain solution to meet Vancouver Island's looming capacity deficit for 2007. BC Hydro views the DPP project as providing the most cost effective supply in terms of being the least cost outcome from a competitively driven process, but also in terms of timing and reliability. The implementation of NCDMP contributes only 140 MW toward the deficit of over 260MW, leaving a balance of 120 MW or greater that needs to be sourced from alternatives which do not provide the same level of reliable, date certain or cost certain supply. Not having enough capacity, nor needing to rely on a significant volume of uncertain supply is not a sufficient nor cost effective solution for Vancouver Island.

14.0 Reference: Table 6, CFT Report, page 18

In this table, cost projections are given for a) base case and b) 230 kV Cable Delayed 1 year, and four other scenarios. The same values are shown in various tables in Attachment A of Appendix J, the Results summary.

1.14.1 Given that the base case already captures a one year delay in the 230 kV cable, i.e. a 2010 in-service date, the "delayed one year" corresponds to an in-service date of 2011. All other values shown in Table 6 relate to a 2010 in-service date. For direct comparison purposes, should the same in-service date not have been applied, instead of mixing them in the same table?

RESPONSE:

The base case assumption regarding the 230 kV transmission circuit is an October 2009 in-service, which reflects a one year delay from the earliest possible in-service date of October 2008. All of the scenarios in Table 6 are being measured relative to the base case assumption, including the 'Delayed 1 Year' scenario which corresponds to an October 2010 in-service.

Refer to the response to BCUC IR 1.29.3 for an explanation about the uncertainty related to the timing of the 230 kV transmission circuit in-service.

14.0 Reference: Table 6, CFT Report, page 18

In this table, cost projections are given for a) base case and b) 230 kV Cable Delayed 1 year, and four other scenarios. The same values are shown in various tables in Attachment A of Appendix J, the Results summary.

1.14.2 Please provide the same information (Table 6/Attachment A) in table form showing the various scenarios by identical cable in-service dates i.e. Table 6 for each in-service date.

RESPONSE:

Information contained in Table 6 represents selected scenarios extracted from Attachment A. Information being requested can be found in Attachment A.

15.0 Reference: Appendix I, Load Forecast, page 56

"Factors contributing to this growth [in VI's service sector] include the following: Possible increases in employment in the public sector following several years of provincial government reductions."

1.15.1 Numerous privatisation or alternative service delivery initiatives are still underway in the provincial government, and the impact of these will continue into 2005 and perhaps beyond. Please justify the assumption that a *possible* increase in employment can be taken as contributing to future growth in this sector, or explain this statement.

RESPONSE:

It is assumed that after the current period of restraint of public sector employment ends, public sector employment will tend to grow with population growth.