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February 1, 2005

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DELIVERED

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Box 250
Vancouver, BC V6Z 2N3

Attention: Robert J. Pellatt, Commission Secretary

Dear Mr. Pellatt:

Re: British Columbia Hydro and Power Authority ("BC Hydro")
Call for Tenders for Capacity on Vancouver Island
Review of Electricity Purchase Agreement
Project No. 3698354

We enclose:

1. Three outstanding undertakings that arose during the cross-examination of BC Hydro's rebuttal testimony as follows:

    (a) proposed Exhibit B-106: response to JIESC T. V.15, pp. 3113 and 3160-3162;

    (b) proposed Exhibit B-107: response to JIESC T. V.15, p.3134;

    (c) proposed Exhibit B-108: response to BCUC staff T. V.15, p.3196; and

2. BC Hydro's Final Argument.

BC Hydro notes that on Wednesday, January 26, 2005, the Panel released its decision with respect to GSX CCC's application (the "GSX CCC Motion") that the Panel recuse itself, but reserved its Reasons. On Friday, January 28, 2005, counsel for GSX CCC indicated that he was considering seeking leave to appeal that decision.

BC Hydro wishes to ensure that if leave to appeal is to be sought, it be sought promptly. A final determination as to how Vancouver Island's capacity needs will be met is required as soon as possible. Accordingly, we respectfully request that the Commission release its Reasons with respect to the GSX CCC Motion at the earliest practical date. This will permit any additional process associated with the review of the EPA to proceed as expeditiously as possible and thereby minimize the prejudice to BC Hydro, its customers and DPP that will be caused by delay.

We thank the Commission for its consideration of this request.

Yours very truly,

LAWSON LUNDELL

Chris W. Sanderson, Q.C.

CWS/bts
encl.

cc: Registered Intervenors

BC HYDRO UNDERTAKING

CALL FOR TENDER FOR CAPACITY ON VANCOUVER ISLAND

HEARING DATE: January 28, 2005

TRANSCRIPT REFERENCE: Volume 15, pages 3113 and 3160 - 3162

REQUESTOR: JIESC

Question: Would you confirm that 91 percent of the energy margin under the QEM arises after you stop using Henwood? In the last 19 years? Please confirm the 91 percent as a non-discounted number.

Response:

In the last 19 years of the DPP EPA, the energy margin calculated by the QEM is 81 percent (discounted) of the total energy margin over the entire Initial Term. This is calculated by discounting cash flows at 8 percent, as is appropriate in the QEM. By using a simple summation of nominal dollars (non-discounted), the value of 91 percent can be obtained.

BC HYDRO UNDERTAKING

CALL FOR TENDER FOR CAPACITY ON VANCOUVER ISLAND

HEARING DATE: January 28, 2005

TRANSCRIPT REFERENCE: Volume 15, page 3134

REQUESTOR: JIESC

Question: I would like to know the type of new generation and the amount of new generation you have, out of Alberta, in that curve. [The curve that is being referenced is that of Mr. Lauckhart's set out in Exhibit B-81A]

Response:

The Henwood Fall 2004 Reference Case forecast has the following generation being added in Alberta in the following years:

Year	Plant Name	Fuel	MW
2005	Genesee	Coal	450
2005	Grande Prairie Wood	Wood waste	10
2005	Clean Energy	Wind	10
2011	Generic GT	Gas	250
2012	Generic Coal	Coal	500
2013	Generic CCCT	Gas	250
2014	Generic GT	Gas	250
2014	Generic CCCT	Gas	250
2015	Generic GT	Gas	250
2015	Generic CCCT	Gas	250
2016	Generic GT	Gas	250
2016	Generic CCCT	Gas	250
2017	Generic GT	Gas	250

2017	Generic CCCT	Gas	250
2018	Generic GT	Gas	250
2018	Generic CCCT	Gas	250
2019-2023	Generic GT	Gas	2250
2019-2023	Generic CCCT	Gas	1250

The Henwood approach is as follows:

1) **Add resources that are actually under construction (e.g., financing is in place and plant is being built).**

2) **Other proposed resources are not added in the timeframe indicated by sponsors if they are not financed and are not under construction and if the model shows them not to be able to cover their entire annual cost (i.e., variable cost plus all fixed costs including annualized costs of capital) in the first year of operation.**

3) **New generic resources are added when the model indicates they will be economic or are needed to meet planning reserve margins. Henwood does not attempt to name these new units since they can be a unit currently being proposed (albeit with a delayed date of operation) or they could be an entirely new project not yet identified.**

BC HYDRO UNDERTAKING

CALL FOR TENDER FOR CAPACITY ON VANCOUVER ISLAND

HEARING DATE: January 28, 2005

TRANSCRIPT REFERENCE: Volume 15, page 3196

REQUESTOR: BCUC

Question: Please provide a comparison of the January 2004 EIA forecast and the numbers that are contained in the short summary for 2005 with respect to gas prices only.

Response:

Please see attached Figures 1 and 2.

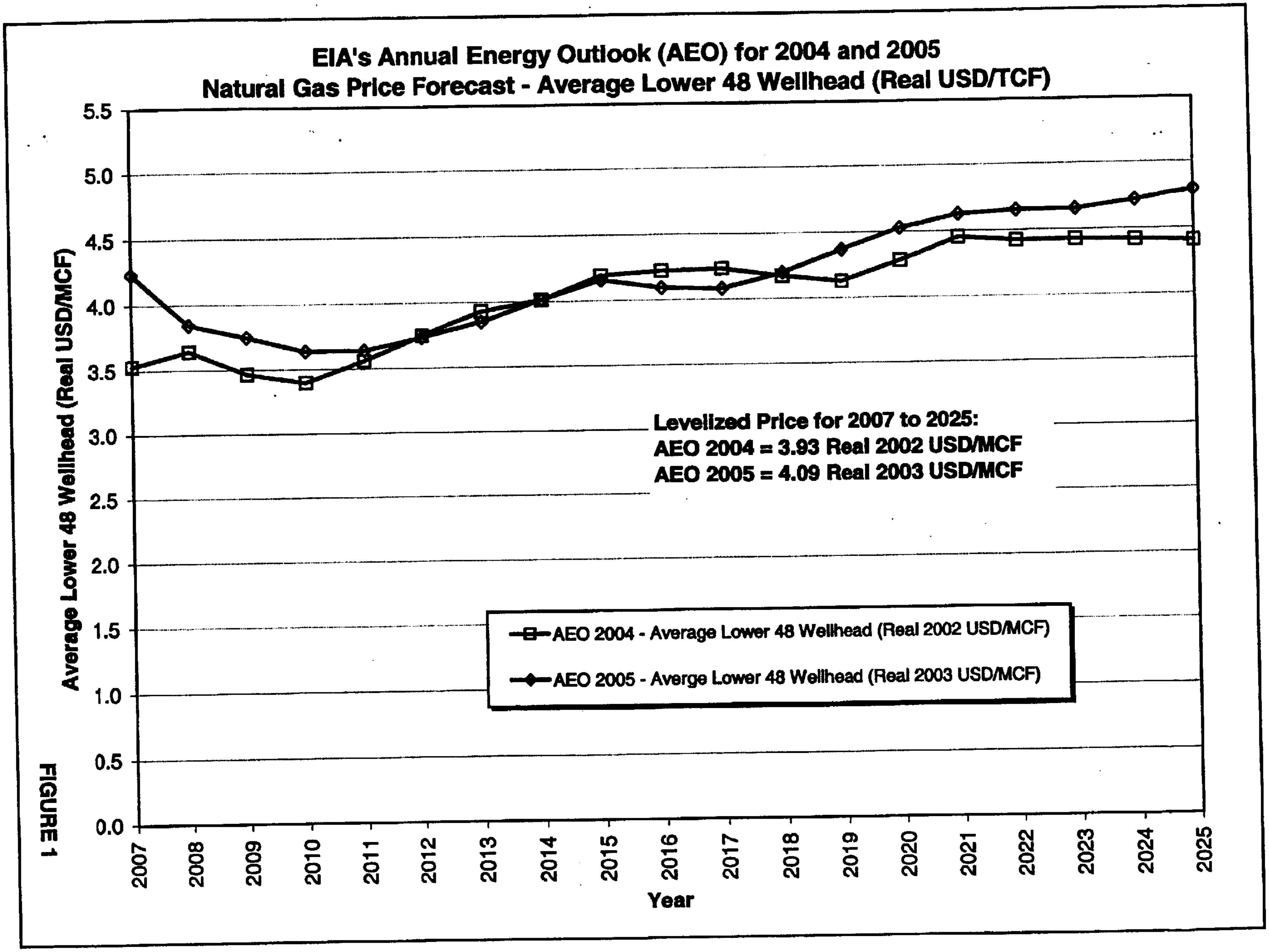
EIA's Annual Energy Outlook (AEO) for 2004 and 2005
Natural Gas Price Forecast - Average Lower 48 Wellhead (Real USD/TCF)
Average Lower 48 Wellhead (Real USD/MCF)
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
Levelized Price for 2007 to 2025:
AEO 2004 = 3.93 Real 2002 USD/MCF
AEO 2005 = 4.09 Real 2003 USD/MCF
AEO 2004 - Average Lower 48 Wellhead (Real 2002 USD/MCF)
AEO 2005 - Averge Lower 48 Wellhead (Real 2003 USD/MCF)
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
Year

FIGURE 1

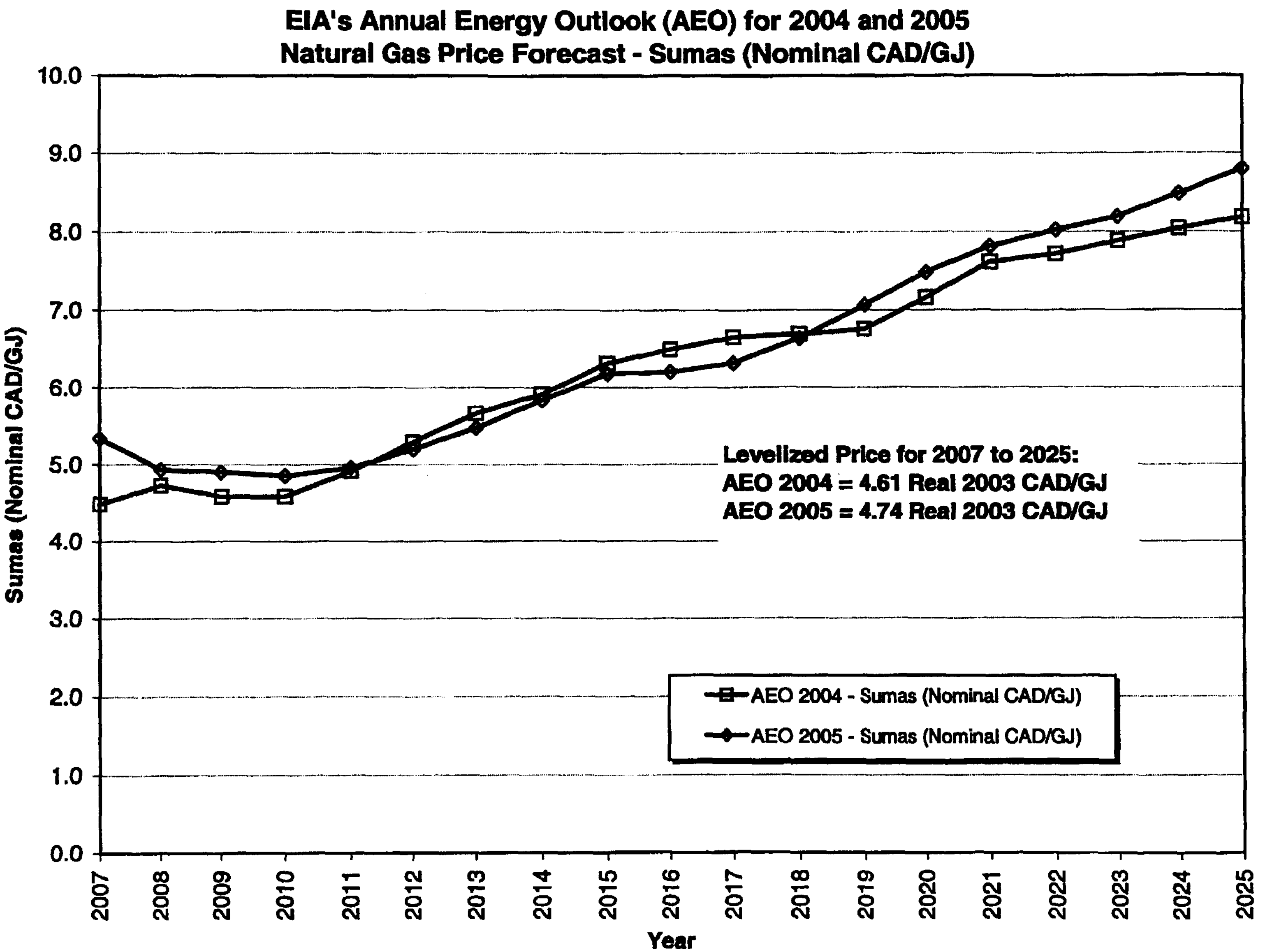
EIA's Annual Energy Outlook (AEO) for 2004 and 2005
Natural Gas Price Forecast - Sumas (Nominal CAD/GJ)
Sumas (Nominal CAD/GJ)
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
Year
Levelized Price for 2007 to 2025:
AEO 2004 = 4.61 Real 2003 CAD/GJ
AEO 2005 = 4.74 Real 2003 CAD/GJ
AEO 2004 - Sumas (Nominal CAD/GJ)
AEO 2005 - Sumas (Nominal CAD/GJ)

FIGURE 2

IN THE MATTER OF THE *UTILITIES COMMISSION ACT*,

R.S.B.C. 1996, C. 473

— AND —

A FILING BY BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

CALL FOR TENDERS FOR CAPACITY ON VANCOUVER ISLAND/

REVIEW OF ELECTRICITY PURCHASE AGREEMENT

Argument on Behalf of

British Columbia Hydro and Power Authority ("BC Hydro")

FEBRUARY 1, 2005

Table of Contents

Introduction

Background, Purpose and Statutory Basis for the Hearing[1]

1. This was an unusual hearing. Unlike most Commission hearings, it was not initiated by an application, request or complaint. Nor was there any statutory obligation to hold a hearing or to require that anything be proved by BC Hydro or Duke Point Power Limited Partnership ("DPP"),[2] the winning bidder in the Vancouver Island Call for Tenders ("CFT"). Rather, there was an electricity purchase agreement ("EPA") and a VIGP Transfer Agreement ("VTA") between BC Hydro and DPP, executed November 16, 2004 and initially filed confidentially with the Commission on November 19, 2004 pursuant to section 71 of the *Utilities Commission Act* ("UCA" or the "Act") along with a non-confidential report on the CFT process ("CFT Report").[3] Section 71 does not require a hearing—indeed, utilities have routinely filed energy supply contracts[4] under this section and predecessor provisions without hearings being held—but allows the Commission to hold one if it considers it necessary.

2. In these circumstances, neither BC Hydro nor DPP are applicants. Rather, they are contracting parties that stand to be affected if the Commission chooses to employ its statutory powers to interfere with the contract they freely entered into with each

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[1] In this Argument, references to exhibits, transcripts, statutes, and cases are in footnotes. The convention adopted for an exhibit is to state the exhibit number, followed by a pinpoint reference if applicable; e.g., "B-9, BC Hydro Response to BCUC IR 1.13.1, p. 2." Transcript references abbreviate the volume as "T#" followed by page references and, if applicable, line references. For example, a reference to Transcript Vol. 6, page 1062, lines 8-17 reads: "T6, 1062/8-17." Similarly, a pinpoint reference starting at line 8 on page 1062 and ending at line 23 on page 1083 reads: "T6, 1062/8 - 1083/23."

[2] This Argument uses the acronym "DPP" to refer to both the electricity supplier and the project itself, according to the context.

[3] B-1 and B-4.

[4] It is common ground that what BC Hydro refers to as an "electricity purchase agreement" is called an "energy supply contract" in the UCA.

other. BC Hydro recognizes that the relationship between the EPA and the VIGP proceedings makes this EPA unlike others in many respects and accepted the Commission's challenge to demonstrate the cost-effectiveness of the solution proposed in the EPA. However, this challenge does not go so far as requiring BC Hydro to prove "beyond a reasonable doubt" or to any other specific evidentiary standard that its proposed solution is "best." What is "best" will depend on what happens in an uncertain future. All BC Hydro can do is show it has taken reasonable steps to identify and implement a cost-effective solution that can meet its needs on Vancouver Island. In the materials filed and testimony provided in this proceeding, it has done that.

3. The EPA review was one in which the scope, substance and issues comprised those things the Commission thought it needed to hear to be able to exercise its jurisdiction, in contrast to proceedings in which an applicant must meet a prescribed and specific statutory test. The sole test to be applied by the Commission is that of the "public interest," a theme that appears throughout section 71 and that can be seen as a generalized and flexible vessel whose shape and content is determined by what the Commission decides to pour into it in any given case. While section 71 gives some guidance in that regard—it permits consideration of specific factors of price, quantity, and availability of the chosen form of energy, as well as its alternatives—the Commission ultimately has the discretion to consider "any other factor . . . relevant to the public interest."[5]

4. The shape of the Commission's review under section 71 also reflected its decision on BC Hydro's previous VIGP Application. There, the Commission concluded that BC Hydro had not demonstrated that VIGP was the most cost-effective means to reliably meet Vancouver Island's electricity needs. It further concluded that the appropriate next resource addition should be on-Island generation, provided the costs of proponents' projects could be confirmed near their expected values.[6] Thus, the

[5] UCA s. 71(2).

[6] VIGP Decision, p. 78.

focus of this review should be on whether BC Hydro's CFT process has identified a generation project that is at or below the expected value of VIGP and is otherwise cost-effective, where the notion of "cost-effectiveness" includes consideration of reliability, dispatchability, timing, and location.[7]

5. Pursuant to that jurisdiction, the Commission ordered a public hearing, invited participation from intervenors and interested parties, and held a pre-hearing conference on November 29 and 30, 2004 to obtain submissions on the scope of the hearing. In the result, it decided to hear evidence on a number of issues, all intended to inform the principal one, that being whether the Tier 1 option is cost-effective relative to the Tier 2 or No Award options to meet Vancouver Island's capacity deficiency starting in the winter of 2007/08.[8]

6. The public hearing was as unusual as the circumstances that sponsored it. Intervenors had trouble accepting the nature of the process with which they were confronted. In particular, they were reluctant to accept attempts by the Commission to expedite its process or adapt its procedures to reflect the specific nature of this inquiry. That has led to a regrettable, and in BC Hydro's submission, unnecessary, preoccupation with process over substance.

7. While intervenors have complained about the narrowness of the scope, BC Hydro has been challenged to address the breadth of the issues the Commission has wanted to consider within an expedited process. When BC Hydro became aware in mid-October 2004 that DPP had succeeded, it had only a month to write, assemble and file the CFT Report and the voluminous material associated with it, respond to many hundreds of information requests, prepare evidence and witnesses, and participate in this proceeding. It also had to deal with an unprecedented number of process issues before and during the hearing.

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[7] VIGP Decision, p.77.

[8] T2: 313-314.

8. At times, some intervenors have sought to exploit the challenges that BC Hydro faced in this regard to allege that it has been insufficiently responsive or indifferent to their concerns. While perhaps understandable, BC Hydro submits that this interpretation is unfair. As Ms. Van Ruyven's opening statement said:

> I appreciate that [the DPP] solution is not a popular one with many audiences. People have strongly-felt and honest concerns with respect to environmental issues around gas plants, exposure to uncertain gas prices, and a variety of other things. BC Hydro management has considered all those concerns and shares some of them. However, every proposed solution has specific concerns. As the utility responsible for providing service, BC Hydro has to make a judgment as to what the most cost-effective solution ultimately will be, having given due regard to all perspectives and all concerns that it is aware of. We believe we have done that, and we believe that after ten years of agonizing over the best means to serve the capacity shortfall, the most cost-effective solution has now been identified and it is time to implement it. Those charged with making that final decision, being BC Hydro and this Commission, have a responsibility to ensure reliable service on the Island, and I believe this is the way it should be done.[9]

9. In saying that it now believes that it has identified the project that should be employed to meet Vancouver Island's capacity needs, BC Hydro does not insist that the DPP project is the best of all hypothetical projects. Rather, it maintains that DPP has the lowest cost of the projects bid into the CFT that met BC Hydro's requirements and is more cost-effective than the Tier 2 or No Award alternatives. To properly assess the alternatives, all projects were required to come forward on a level playing field. With the Commission's encouragement, BC Hydro adopted a competitive process to achieve that and believes it has succeeded in identifying an appropriate outcome. Of course, a competitive process is different than a planning process in that it seeks to obtain firm commitments from other parties and, having obtained them, creates legal and fairness obligations to those parties. BC Hydro

[9] B-55 (opening statement filed on January 16, 2005 but not read into the record).

believes it is very important that the regulatory process not be employed to circumvent or undermine the competitive process once undertaken.

10. The challenge with respect to timing in connection with this proceeding also affects this Argument. There is little attempt in the body of the Argument to summarize material that has already been presented in the CFT Report or the testimony. Where possible within the time allotted, BC Hydro has provided references for points in this Argument, but it does rely on the entirety of the CFT Report and its evidence in support of the conclusions it asks the Commission to draw. Moreover, there are many issues dealt with in the testimony and the CFT Report that may not be captured under the precise headings that are identified in this Argument. We have tried to deal with what seemed most contentious, but, to the extent that we have failed to do so, we ask the Commission to have regard to the record generally.

Hearing Issues

11. The Commission identified a number of interrelated issues that it saw as needing to be addressed in order to satisfy the public interest; BC Hydro also identified certain sub-issues arising from intervenor evidence and information requests; and the Commission identified a further related issue after the Panel 2 session. These issues can be summarized as follows:

    (a) Commission authority to disallow filed EPA in favour of new EPA (includes duct firing capacity);[10]

    (b) timing risk of proposed new 230 kV circuit to Vancouver Island;[11]

    (c) performance risk (project availability, reliability and contractual provisions for non-performance);[12]

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[10] T12: 2517/16-2518/8; T14: 2883/18-2886/6.

[11] T2: 309/23-310/10; T6: 1077/7-19.

(d) gas supply/price risk (including gas and electricity price forecasts);[13]

(e) value of energy;[14]

(f) gas transportation costs and risks;[15]

(g) peak demand forecast for Vancouver Island;[16]

(h) CFT criteria;[17]

(i) greenhouse gas emissions;[18]

(j) treatment of payment under the VTA;[19]

(k) NorskeCanada demand management proposal (NCDMP).[20] and

(l) cost-effectiveness analysis.

12. BC Hydro's submissions on these issues are set out below. While the duct firing issue arose during, as opposed to before the hearing, it requires consideration of the Commission's powers under the UCA. For that reason, we address it first. We then address the balance of the issues identified as within scope and conclude with an overall comment on the principal issue, that being the comparison of the EPA with the Tier 2 and No Award scenarios.

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[12] T2:310/14-17; T6: 1078/3-16.

[13] T2: 310/19-311/9; T6: 1078/17-21.

[14] T6: 1079/17-1080/15.

[15] T2: 312/25-313/19; T6: 1078/22-23.

[16] T2:311/11-26; T6: 1078/24-25.

[17] T2:312/1-22; T6: 1078/26-1079/10.

[18] T6:1081/3-10.

[19] T6: 1081/13-22.

[20] T6:1081/23-1082/2.

Commission Authority to Disallow Filed EPA in Favour of a New EPA

13. While on Panel 2, Ms. Hemmingsen acknowledged her concern "that [the CFT] didn't produce . . . the most cost-effective outcome in terms of what was bid in."[21] Her remarks were made in the context of the simplified evaluation methodology employed in the QEM comparison of DPP's separate bids for an EPA with and without duct firing. This raises two issues. The first is to reconcile Ms. Hemmingsen's remarks with her testimony elsewhere and with BC Hydro's position that the EPA is a cost-effective solution to Vancouver Island's capacity problems. The second is to explore the Commission's authority to require, encourage, or otherwise comment on the desirability of including duct firing in the Duke Point project.

14. A critically important fact in analyzing these issues, and, under the circumstances, a fortuitous one, is that both of DPP's bids include duct firing capacity. Under Appendix 5 of the EPA, DPP has committed to include duct firing capability in its plant, and full duct firing was specified in DPP's bidder information sheets for both bids: the technical parameters for the heat recovery steam generator and the cooling tower specified that this technology would be "designed for maximum utilization of the Steam Turbine/Generator with full duct firing."[22] The only difference between the two bids was that in one, the capacity was contracted to BC Hydro; in the other, it was left available to the merchant market. But Mr. Campbell made clear in his direct testimony that the capacity would be built, and that it would be available to BC Hydro:

> So for clarity, the contract is for 252 megawatts. Under that contract, that capacity can go up by a factor of 5 percent to 105 percent. That would bring the capacity of the plant to 264.6 megawatts, or the contracted capacity available to B.C. Hydro up to 264.6.

[21] T8:1751/17-19.

[22] BC Hydro response to BCUC IR 1.36.3 (Bidder Information Sheet—DPP Tender #1, Seller's Plant Description, p. 2 and Bidder Information Sheet—DPP Tender #3, Seller's Plant Description, p. 2), as well as C17-8 (attaching unredacted pages of EPA pursuant to Order No. G-119-04) at p. 74.

> I would note that the plant, with its duct firing capability of approximately 28 megawatts would increase that number up to 292.6 megawatts[,] would increase that number up to 292.6 as its capability. And that capability, for clarity, is available to Vancouver Island to meet the capacity shortfalls or requirements on the Island, because that capacity will be built in this plant.[23]

15. With inclusion of duct firing, the overall capacity of the plant thus closely aligns with the F2008 forecast demand/supply deficit of 280 MW.[24]

16. As to the first issue, while Ms. Hemmingsen expressed her concern that the structure of the CFT prevented BC Hydro from acquiring this additional power (at least in that process),[25] that does not mean that the proposed EPA is not a cost-effective option or not in the public interest. The evidence is clear that the CFT process favoured smaller portfolios because of the NPV methodology that was employed.[26] Accordingly, it is not surprising that the CFT process failed to secure the additional cost-effective resource available through duct firing. While this is a concern for the design of future processes and is perhaps a reason to introduce more flexibility in such processes, the concern is effectively met here because the duct firing aspect of the proposal will be built in any event. Because BC Hydro controls dispatch over the facility,[27] the value of duct firing lies almost exclusively with BC Hydro. That is, while DPP could theoretically sell the additional 28 MW to another party, neither DPP nor that other party would know when the 28 MW was going to be produced. BC Hydro has control of that through its control of dispatch. Accordingly, the additional energy would have very limited value to another party. Thus, as DPP's testimony made clear, the additional output should be available on terms that are favourable to BC Hydro.

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[23] T10: 2210/13-25.

[24] See B-98 (showing 280 MW forecasted shortfall in F2008, further to December 2004 Load Forecast).

[25] T8: 1741/15-20.

[26] B-35, Tab 2, direct testimony of Mary Hemmingsen, p. 10.

[27] B-6 (see Section 9 of the EPA).

17. As to the second issue, BC Hydro submits that the Commission cannot require DPP to sell the additional 28 MW to BC Hydro and should not try to do so. Under section 71 of the Act, the Commission may choose between two remedies if it believes action on its part is necessary to protect the public interest. First, it can disallow all or part of the EPA. Second, and alternatively, it can approve the EPA, but impose such non-contractual terms and conditions as are required to protect the public interest. *What the Commission cannot do is disallow parts of the EPA and substitute terms and conditions that it thinks might be more desirable in the contract.* This limitation on the Commission's power flows from the fact that one of the parties to the contract, DPP, is not a public utility and is not regulated by the Commission. The unique and limited nature of the Commission's powers over an EPA are reflected in the fact that they appear not in Part 3 of the Act, which gives the Commission its general jurisdiction over public utilities, but in Part 5; further, they involve a party over which the Commission otherwise has no jurisdiction.

18. BC Hydro acknowledges that the Commission could approve the EPA under section 71(3)(b) of the Act with conditions that would require BC Hydro to contract for the additional 28 MW of capacity from DPP before it is allowed to proceed with the EPA. But BC Hydro does not advocate that the Commission employ this authority. Rather, it believes that the EPA should be approved unconditionally and the decision of whether to buy the additional 28 MW of capacity from DPP should be left to BC Hydro. If BC Hydro chooses to buy the additional 28 MW, it would have to do so through another agreement that would be filed as an EPA with the Commission. If BC Hydro chooses not to do so because it concludes that there are more cost-effective ways to acquire an additional 28 MW, it should be free to do that and justify its decision in a REAP (Resource Expenditure Acquisition Plan) or revenue requirement proceeding in which that decision would be reviewed. In short, the record of this proceeding has identified a good opportunity to acquire a small but cost-effective increment of capacity, but the Commission is not called upon to make a decision as to whether that opportunity is worth pursuing, and the record is incomplete for that purpose. Accordingly, the Commission ought not to make the acquisition of the additional 28 MW a condition for approving the EPA.

Timing Risk of Proposed 230 kV Circuit to Vancouver Island

19. The question of the timing of the next increment of transmission supply to the Island resulted in DPP being characterized at various points in the proceeding as a response to a "short-term problem"[28] or similar words, the reference being to the expectation that the proposed new 230 kV AC circuit will be in service by 2008 or 2009. In particular, DPP was contrasted as a competing alternative to that circuit.[29]

20. This is an incorrect, or at least incomplete, characterization of the project and does not accord with the VIGP Decision. There, the Commission found as a fact that the appropriate next resource addition on Vancouver Island should be on-Island generation, subject to cost considerations.[30] No party in the VIGP proceeding sought reconsideration of that determination, and the Commission considered it to be a relevant determination for this proceeding.[31] Ms. Van Ruyven testified to this need, and there was testimony from Mr. Mansour on this point in both the VIGP hearing and this hearing. BC Hydro supports the construction of the 230 kV transmission circuit as soon as possible. It has confidence in BCTC's ability to carry out its responsibilities in that regard. However, the fact remains that the completion date for the circuit is simply a "best efforts" assurance, not a financial commitment. BC Hydro does not believe it would be prudent to plan on the circuit being available earlier than F2010.

21. As Ms. Van Ruyven explained, both generation and transmission solutions are required to ensure that Vancouver Island Region has a level of reliability comparable to that of the Lower Mainland:

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[28] See, e.g., T2: 1099/3-4; T10: 2297/4-5.

[29] Because transmission deferral credits were eliminated from the QEM process, the timing of the next increment of transmission supply to the Island is not relevant to the CFT; it arises, though, in the context of the post-CFT cost-effectiveness analysis, and was therefore within the scope of the proceeding.

[30] VIGP Decision at p. 78.

[31] T2: 307/11-16.

> I look at the Island in the long term, and I don't look at the 230 kV cable as a competing project to the successful outcome of this Call for Tender in a 252 megawatt plant. Over the next 20, 30, 40 years there will continue to be additions of on-Island generation along with cable replacements or additional cables, so that the Island can have the same reliable services as the Lower Mainland.[32]

22. Ms. Van Ruyven's testimony also made clear that the BC Hydro system is reaching a net capacity balance, and that new capacity additions will have to be made on the Mainland to serve growing load on the entire system. The additional capacity to Vancouver Island will play a part in serving that objective. Thus, DPP will provide capacity benefits for the entire system once the 230 kV circuit is complete, including potential deferral of additional cables on that circuit.[33]

23. In the VIGP proceeding, Mr. Mansour testified extensively that, from a system stability point of view, more generation on the Island is desirable and will continue to be desirable. He recounted how, in response to growing concerns about Vancouver Island supply, the Commission had asked BC Hydro in October 2000 to report on whether it had undertaken all reasonable planning initiatives to ensure continuous reliable service to all Vancouver Island ratepayers. Mr. Mansour noted that BC Hydro's view at the time was that it was non-compliant with planning criteria. He outlined the attempts to address the problem and confirmed that the situation was no better in June 2003. He also said that it was not simply a question of being at risk of meeting peak load, but one of overall reliability, including both the number and duration of potential outages:

> In operating under these circumstances, we are losing ground by the day. We push the limits on major equipment loading as we speak, hoping that it will not impact its life cycle, but it may. We rely heavily on mass trans-generation [*sic*] on the Island, hoping that there is enough water to last for a long duration of outage, but there may not be at times. And we rely heavily on an old HVD [C]

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[32] T6: 1099/7-15.

[33] T6: 1100-1103.

> system which may give up from natural causes sooner. It is not just the total outages that expose the deficiency of supply to Vancouver Island. Every time we have a single outage by plan or force, we are exposed.[34]

24. Mr. Mansour went on to note that a long-term approach, combining both generation and transmission, would be needed to address the problem:

> Bringing the quality of supply to Vancouver Island to a standard comparable to the mainland will not happen overnight, and will not happen with the very next project. It would happen over a long term only through a combination of enhanced transmission and generation over many years. Deciding which project to pursue first is less important than having the first project in operation in time.
>
> . . .
>
> I feel that we have done enough studying, enough analyzing, and we are compromising enough, and really enough is enough, in taking the risk of failing to secure essential supply to that region and to our customers.[35]

25. In this proceeding, Mr. Mansour was invited to revisit his comments in light of the time elapsed since 2003 and the progress made in studying and preparing for the 230 kV circuit:

> THE CHAIRPERSON: And I'm thinking about your evidence in 2003 and . . . it occurred to me that this was one of the highlights of the decision, and so I included your quote in the decision. And at the time there the 230 was contemplated . . . the application was for VIGP, and it was my impression that you were of the view that VIGP should be approved and that the next step was the 230 kV line. Is that correct?
>
> MR. MANSOUR: A: That's correct, sir.
>
> THE CHAIRPERSON: And the VIGP project is or was similar to DPP.
>
> MR. MANSOUR: A: Yes.

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[34] VIGP Transcript, T4: 777/18-778/3. See B-53: request for admission of VIGP evidence.

[35] VIGP Transcript, T4: 778/4-22.

> THE CHAIRPERSON: Is it still your view, sir, that that project should proceed before the 230 kV line?
>
> MR. MANSOUR: A: My view hasn't changed from 2003, Mr. Chairman. The quote of "enough is enough" I still believe in. I have said at the time that we've been studying this for a long time, and let us get the soonest thing that can be there.
>
> . . .
>
> I am more concerned even than I was in 2003. . . . [I]f you take the 30-year view, 25- or 30-year view of Vancouver Island, as we said in our submission that combination of generation and transmission to supply the Island is the right long-term vision.[36]

26. Mr. Mansour's remarks relate to the fact that the plant is not just to address what has been characterized as a few cold days or weeks; it fulfills the N-1 planning criterion, which relates to such things as making sure that a facility is in place if one of the 500 kV cables goes down or if another plant has an outage.[37] As explained in the VIGP proceeding, there are various real-time operational factors that would increase the amount that a plant such as DPP would run. These include: (i) operation during near-peak periods when the 500 kV circuit has exceeded its two-hour thermal rating; (ii) operation to ensure adequate capacity when on-Island hydro-electric capacity is reduced below the maximum value of 450 MW (the maximum continuous operation for three hours); and (iii) operation to mitigate the impact of low probability, multiple contingency events leading to disconnection of the Island system from the Mainland system.[38]

27. Quite apart from these electric system considerations, as discussed above, the completion date of the 230 kV AC system is uncertain. There are delay factors associated with the timing of the 230 kV circuit, as brought out in Mr. Keough's

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[36] T10: 2404/17-2406/2.

[37] T6: 1251/23-1252/1.

[38] For details, see VIGP Exhibit 4-JJ (included in B-53: request for admission of VIGP evidence).

cross-examination of the BCTC panel.[39] Notwithstanding Mr. Barrett's enthusiasm and commitment, the 230 kV system included in BCTC's capital plan will still have to be the subject of a separate CPCN application before the Commission[40] and other related applications to various permitting agencies in Canada and the United States,[41] all of which may take longer than expected to conclude. The delay risks associated with these permitting processes were taken into account in the cost-effectiveness analysis discussed below. Assuming a 280 MW demand/supply shortfall in F2008 and a F2010 in-service date for the 230 kV system (October 2009), the Tier 1 outcome costs $61 million less than the No Award scenario (NPV, 2003 dollars).[42] Each year of further delay in the 230 kV in-service date increases the Tier 1 benefit relative to the No Award scenario by approximately $30 to $40 million per year (NPV, 2003 dollars).[43]

Performance Risk

28. BC Hydro believes that the provisions of the EPA coupled with the specific characteristics of the DPP provide ample protection against performance risk.[44] First, there are substantial disincentives for non-performance, including a non-refundable deposit of $30 million (development security).[45] This provides financial protection to BC Hydro if DPP fails to perform. Second, the project is the most advanced of any of those for which bids were received, thus minimizing permitting and construction risk. Third, the project uses proven technology that has been

[39] T10: 2331-2388.

[40] T6: 1120/14-19.

[41] See Exhibit 4A in the VIGP hearing (VIEC Supplementary Response to BCUC IR 21.3, attaching *Project Planning Report: 230 kV Transmission Circuit from Arnott to VIT*).

[42] B-99 (update to Attachment A of Appendix J to B-1).

[43] B-99 (all tables on pp. 1-2).

[44] T7: 1505/13-17.

[45] T7: 1390/9-17.

employed throughout North America. These factors combine to create a very low performance risk associated with this project.

Gas Supply/Price Risk

29. Under the CFT structure, BC Hydro offered to assume a gas supply price risk, but was not similarly willing to accept the price risk associated with other fuels. The rationale was based on careful consideration of two criteria: (i) supporting active competition; and (ii) ensuring a cost-effective outcome for ratepayers by allocating risks to the parties best able to bear them. There were suggestions that this in some way biased the CFT in favour of gas-fired solutions. BC Hydro disagrees.

30. The CFT was BC Hydro's attempt to obtain a specific product—reliable capacity on Vancouver Island—through a competitive process. BC Hydro's focus was acquiring a cost-effective solution for its ratepayers. This required a process that would attract healthy competition, but not one that would necessarily be equally attractive to all bidders. Consistent with this approach, BC Hydro offered to take risks where it was best suited to do so, but assigned to bidders those risks it was not better able to control. Thus, BC Hydro assigned alternative fuel price risk and performance risk to the bidder, but indicated a willingness to accept gas price risk because it already manages gas price risk. Spot and forward market mechanisms for managing gas price risk are well established in BC and BC Hydro feared that bidders would demand an unacceptable premium if required to assume this risk.

31. In short, BC Hydro's decision to accept gas supply risk reflects the existence of established spot and forecast markets for gas and its internal capabilities and risk tolerances, rather than a bias towards a particular fuel type. Each type of bidder is more or less well-suited to meet BC Hydro's specific needs and BC Hydro was correct not to forsake a CFT process designed to serve its ratepayers' interests so as to accommodate the needs of specific bidders. As Mr. Sorensen put it, a contract that must be performed in Ottawa may impose additional costs on non-Ottawa

bidders; but it is not discriminatory to decline to pay the transportation costs of those who do not live in Ottawa.[46]

32. In BC Hydro's case, it has a significant gas supply portfolio that it manages.[47] Increasing the size of that portfolio will not require additional resources nor diminish the success that can be expected from management of those existing resources. Thus, BC Hydro does not need to pay a premium to obtain the gas supply management expertise from bidders.

33. BC Hydro acknowledges that the need to source and supply gas to DPP introduces a risk not present with other non-gas-fired options. A fixed price take-or-pay contract for a plant's output over its economic life, regardless of fuel price, also has significant risks. That is, a fixed price contract for an alternative fuel carries with it the risk of regret if gas prices are subsequently lower than forecast. Thus, there is risk associated with any form of commitment BC Hydro makes, particularly when it is for an extended period of time. Here, BC Hydro has chosen the risk that makes the most sense, given its specific capabilities relative to the market.

Value of Energy

34. BC Hydro's cost-effectiveness analysis and the testimony of the Rebuttal Panel should significantly reduce any residual concern with the acceptance of the gas supply price risk. The cost-effectiveness analysis is discussed in a later section of this Argument. It shows that while a gas tolling plant solution may not be cost-effective in every foreseeable circumstance, it is a robust solution through a broad range of future outcomes.

35. That testimony was considerably strengthened by the corroborative testimony of Dr. Pickel and Mr. Lauckhart. The two completely separate models employed by their

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[46] T8: 1797/2-24.

[47] T8: 1666/20-26.

respective firms are the dominant models used for assessing, financing, and obtaining approval of new generation projects throughout western North America. Both models cover the entire market area within which BC Hydro transacts, as acknowledged by Mr. Fulton and all witnesses appearing on behalf of BC Hydro.[48]

36. While BC Hydro does not seek to justify the plant on the basis of the value of the energy it will generate, there exists the potential that the energy upside associated with the plant will lead to realization of BC Hydro's 100% Cost Recovery scenario. That has been the experience with the Fort Nelson simple cycle generating plant.[49] However, in the QEM and cost-effectiveness studies, BC Hydro does not suggest that the plant will pay for itself through energy rates. Rather, it merely suggests that the expected value of energy sales will be sufficient to cause the net cost of Vancouver Island capacity to be less with DPP than under any alternative scenario.

37. The only contrary evidence to that provided by Dr. Pickel and Mr. Lauckhart was Mr. Fulton's. Mr. Fulton dismissed the work of what he calls "the economic forecasters"[50] in favour of the market. But Mr. Fulton's testimony and conclusions do not withstand scrutiny.

38. First, Mr. Fulton suggests substituting the wisdom of the market for the hubris of the forecaster. BC Hydro would be prepared to do the same if such wisdom was available. However, BC Hydro recognizes, and Mr. Fulton conceded, that the market must share its wisdom before it can be of assistance. BC Hydro and the Commission must plan for the long term—a period for which negligible information is available from the market. Where there is no market information, there is no wisdom in evidence, and the most that any utility or regulator can do is employ the best economic forecasting available with rigorous regard to market fundamentals. In its forecasting, BC Hydro uses market data for as long as it exists

[48] T12: 2553/8-13.

[49] T9: 1890/11-19 (examination-in-chief of Bill Peterson).

[50] T12: 2582/16-21.

and then shifts to a forecast that seeks to determine the price-setting resource within the region, assuming that, on average, that resource will need to earn a reasonable economic return for there to be sufficient incentive for supply to meet demand over time. This assumption is consistent with basic economic theory, which in turn is based on market fundamentals.

39. BC Hydro recognizes that there can be circumstances where future expectations do not materialize, even over the long term. To reflect that possibility when developing its electric forecast, BC Hydro gave equal weight to a second scenario, one that Mr. O'Riley can see actually occurring under only the most extreme circumstances—that is, the 25% Cost Recovery scenario. Mr. O'Riley said that he was hard pressed to imagine that all the circumstances identified in the slides for the February 26, 2004[51] presentation would exist at once, but, nevertheless, assumed they would for the purposes of forecasting. The result is that BC Hydro's forecast assumes that a gas plant will only return approximately 62.5% of its capital over time (i.e., equal weighting of the 25% Cost Recovery and 100% Cost Recovery scenarios).

40. In fact, this represents a market failure and is hard to justify under market fundamentals. Consequently, it is a considerably more pessimistic scenario than Mr. Lauckhart foresees based on his step-by-step addition of new plants of all varieties throughout the WECC. It is important to stress that the Henwood model looks at the specific resources available in the WECC without regard to fuel type and adds them in the order most likely to meet the model's expectations with respect to growing demand. Dr. Pickel's model adopts a similar approach. It is striking that both models, independent of each other and without collaboration between the witnesses, yield results that are broadly corroborative of BC Hydro's.[52]

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[51] B-97, O'Riley Tab, February 26, 2004 Presentation, slide 4.

[52] Examination in chief of Dr. Pickel and Mr. Lauckhart, T14: 3004/20-23; 3005/2-3.

41. It is also striking that looked at over time, the range of heat rates that result from different models are broadly consistent and at the low end of the range that has existed over time. The potential for the significant spikes of the early parts of this decade—which would yield significant benefits to a gas-fired generating plant—remain, and all of the evidence seemed to be that those short-term periods of significant gain are likely over the length of the contract.

42. There are some important things to note with respect to the combined testimony of Mr. O'Riley, Mr. Lauckhart and Dr. Pickel. The first is that each produced a smooth curve of average heat rates over time. None expect actual heat rates to remain smooth over time. They will fluctuate annually and, more importantly, daily—perhaps dramatically. It is hourly or daily heat rates that will determine dispatch. The greater the volatility around the average, the greater will be the benefit to BC Hydro of having assumed the gas price risk for a dispatchable plant. That is, the average hourly margin associated with production at the plant will be determined by the average heat rate during those hours when the heat rate is sufficient to encourage production or the plant is required for capacity purposes. When the plant is not running, the energy margin is unaffected no matter how low the heat rate goes. Thus, the energy margin will be determined by the average heat rate of those hours when production is occurring.

43. In current conditions, which are clearly abnormal as can be seen from Exhibits 81A and 81B, CCGTs operate approximately 50% of the time.[53] These heat rates are fairly stable and thus the margins during these hours tend to be low and stable. However, as the current excess supply is soaked up by new demand, heat rates will climb sufficiently to induce new investment. If new investment is not forthcoming, shortages will begin to manifest on some days, and spikes in heat rates will occur as inefficient resources are required to serve load. Eventually, market fundamentals will spur the creation of new resources, which will bring heat rates back down. Thus, the smooth curves presented by Mr. Lauckhart and Dr. Pickel assume the

market is working efficiently. To the extent the market is not working efficiently, incumbent generators can be expected to perform more profitably than would be predicted under a smooth transition.

44. No reasonable doubt was cast on this outlook for the future by Mr. Fulton. He really had only two points to make. The first is that the best way to predict the future is based on the cumulative wisdom of the many players who make up the market. Mr. O'Riley agreed with this, as did Mr. Lauckhart and Dr. Pickel, and all claimed to make as much use of market information as possible. Regrettably, as ultimately conceded by Mr. Fulton, market information does not exist for the vast majority of the period during which the Duke Point facility will operate. While Mr. Fulton maintained that a market may exist, the value of a market without trades to those who wish to make investment decisions now is negligible.

45. Having himself forsaken the market because of lack of data, Mr. Fulton was left to complain about the power price forecast employed by BC Hydro because the power price was developed through the Henwood model, whereas the gas price employed the EIA gas price forecast. Mr. Fulton would have preferred BC Hydro to use EIA's power price forecast. His testimony in this respect can be viewed as nothing other than opportunistic. It was Mr. Fulton who emphasized the importance of considering market fundamentals in developing a market price in the absence of direct market information. Instead of looking to those market fundamentals, Mr. Fulton seems to have adopted a forecast based on the name of the organization producing it or based on the results that it would provide. Neither basis is satisfactory.

46. The evidence is undisputed that the EIA forecast is based on a mix of North American-wide values generated by cost of service regulation on the one hand and estimates of market prices on the other.[54] The forecast is not differentiated by location, despite significant dislocations in electricity prices across North

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[53] T15: 3137/26-3138/4.

[54] B-97, direct testimony of Chris O'Riley, p. 1.

America.[55] In cross-examination, it was suggested to the Rebuttal Panel that cost of service prices are higher than market prices. While over time that may or may not be so, it is undeniable that market prices are dramatically higher than the average cost of many of the old resources in the WECC, particularly BPA and BC Hydro's hydroelectric resources. The market price is set by the last unit needed to meet demand, not by the marginal cost of running hydro resources. It has been a long time since we have seen $3 to $5 per MWh prices in the WECC, even though that is the operating cost of a large percentage of its hydro resources. It is also a long time since we have seen prices consistently close to the $24 per MWh that are associated with the generation component of BC Hydro's system as determined in the Heritage Inquiry. There is simply no escaping that use of the EIA power price forecast by Mr. Fulton to predict market prices was a fundamental error in his analysis. Without that error, Mr. Fulton's market rates can only be derived by assuming that current market conditions will last indefinitely without regard to any market fundamentals. To simplistically assume that current conditions will prevail for the next 28 years without any regard to market fundamentals would be to contradict Mr. Fulton's own preferred approach and abdicate any responsibility to forecast the future. BC Hydro believes that it and the Commission can do better.

47. Although both Mr. Lauckhart and Mr. Pickel rejected Mr. Fulton's price forecast, they did seek to forecast DPP utilization using that forecast. They both concluded that even with the unrealistic relative prices he assumed, Mr. Fulton significantly underestimated utilization. This is in part because of incorrect assumptions (e.g., assuming that gas transportation charges from Sumas were a variable cost instead of a fixed cost) and because of the unsophisticated nature of the model (e.g., no time or locational differentiations).

48. BC Hydro plans to buy gas for ICP and DPP under a portfolio of gas commodity arrangements that will include purchases at both Huntingdon/Sumas and Station 2,

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[55] *Id.*

with the terms of those purchases varying from daily to multi-year.[56] Mr. Guenther suggested that future transactions may be increasingly focused on Station 2.[57] That may be so, but BC Hydro believes that Huntingdon/Sumas is sufficiently liquid for executing transactions; BC Hydro could buy gas at Huntingdon/Sumas or it could buy additional gas transportation from Station 2, but it would not be required to do so.[58] Indeed, BC Hydro would only shift purchases to Station 2 if that would lower overall gas purchasing cost or risk.[59] Thus, BC Hydro does not believe that if an increasing focus on Station 2 occurs, it will have an adverse effect on the delivered cost of natural gas on Vancouver Island.

Gas Transportation Costs and Risks

49. BC Hydro expects to conclude arrangements with TGVI for the transportation of natural gas to DPP. Based on previous precedents with ICP[60] and the expectation that gas transportation costs will be near the values used in the QEM, BC Hydro is confident that it will be able to reach an agreement with TGVI that protects the interests of BC Hydro ratepayers. BC Hydro requested, and TGVI provided, detailed information on both gas transportation costs and development risks for each of the modelled portfolios. For DPP, the costs translated into a schedule of annual tolls starting at approximately $16.3 million in 2008 (first full year of operation) and falling to approximately $12.7 million by 2031 (nominal dollars).[61] In present value terms, this is approximately $131.6 million (2006 dollars, NPV).[62] Due to the recent amendment to the transportation service agreement between the

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[56] B-9, BC Hydro response to BCUC IR 1.23.2.

[57] C19-11.

[58] B-12, BC Hydro response to JIESC IR 1.2.0(a).

[59] B-12, BC Hydro response to JIESC IR 1.2.0(f).

[60] See B-9, BC Hydro response to BCUC IR 1.23.4 (attaching agreement with TGVI for gas transportation to ICP and Compressor Facility Agreement for Texada Island Compressor Station).

[61] B-9, BC Hydro response to BCUC IR 1.23.5, Table IR 1.23.5.

[62] B-4, BC Hydro response to BCUC IR 2.47.1.

TGVI and the Vancouver Island Gas Joint Venture, the effect of which was to reduce the billing determinants on the TGVI high pressure transmission system, these costs are expected to increase by approximately $1 million per year for DPP, or less than $10 million in present value terms.[63] This brings the total expected cost of gas transportation to about $142 million (2006 dollars), which translates into about 10% of the total portfolio cost for DPP.[64]

50. There is a very low risk of not being able to obtain gas for Duke Point. In particular, it is likely that BC Hydro and TGVI will enter into an agreement by November 2005; that agreement may not be a long-term agreement, but it would be an agreement for firm (non-interruptible) service. In any case, BC Hydro is confident that gas transportation, as a regulated service, will be readily available (indeed, if necessary, such service may be compelled on such terms as the Commission may direct);[65] it did not have the same level of confidence about transportation arrangements for other fuels.[66]

Peak Demand Forecast for Vancouver Island

51. The CFT Report incorporated data from the October 2004 Electric Load Forecast, which was based on an assumed rate increase of 8.9%. Before the hearing, the Load Forecast was updated to reflect the actual rate increase of 4.85% resulting from BC Hydro's Revenue Requirements application. This Load Forecast, dated December 2004, was filed as an exhibit[67] and resulted in consequential amendments to Table 5 of the CFT Report, the most pertinent of which was to increase the

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[63] T6: 1210/2-22.

[64] B-4, BC Hydro responses to BCUC IRs 2.46.6 and 2.47.1. Dividing $142 million by $1,144 million yields approximately 12%. However, the numerator is stated in 2006 dollars, the denominator in 2003 dollars. Restating the numerator in 2003 dollars would bring the percentage down to about 10%.

[65] See UCA s. 30. As stated, though, BC Hydro does not expect to have to ask the Commission to invoke this power; it expects to be able to reach an agreement with TGVI.

[66] T7: 1489/13-21.

[67] B-67.

Island's forecast demand/supply deficit in F2008 from 262 MW to 280 MW.[68] Based on information obtained in the last year, though, this may be a conservative forecast. An explanation is in order.

52. The gap between the peak demand experienced in the Vancouver Island Region and the supply resources available to meet that demand has grown considerably since the VIGP decision. In both January 2004 and January 2005 there were extended cold periods, with a F2004 record peak demand of 2253 MW and a F2005 peak demand to date of 2317 MW.[69] The average temperature on these two peak days was -4.7° C (04 January 2004) and -4.1° C (15 January 2005).[70] With actual temperatures close to BC Hydro's design temperature for the Island of –3.6° C,[71] the peak response to temperature is estimated to be in the order of a 40 MW increase for a one degree Celsius drop in daily average temperature.[72]

53. The recent weather data has a number of implications. First, on a preliminary weather-adjusted basis, the peak was met or exceeded for eight days in January 2005; second, the forecast peak for F2008—the date by which new capacity is needed on the Island—was met or exceeded for four days in January 2005; third, the weather pattern has been such that there was not merely a high peak on a given day, but, rather, an extended period or extended set of days with relatively high peaks.[73]

54. The size of the gap that is apparent from what has already happened makes it clear that the forecasts of Mr. Miller filed by GSX CCC as part of this proceeding were inadequate. Mr. Miller based his forecast solely on observed load over the past ten

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[68] B-1 (p. 15) and B-98.

[69] B-68. See also T9: 1896/14-1899/16. (Figures include an estimate of 60 MW for the Gulf Islands but are approximate because of a time lag in finalizing Gulf Island load data.)

[70] *Id.*

[71] See B-67, p. 50 (also discussing the increase of design temperature last year from -4.4° C to -3.6° C).

[72] *Id.*

[73] Id. See also T9: 1898/10-20.

years. There are two shortcomings to this approach relative to BC Hydro's. First, he has used a relatively short historical period of ten years, compared to BC Hydro's use of 30 years. Second, he has used actual load instead of temperature. This obscures cold days, even in the past ten years, that occurred on holidays or weekends or when industrial areas were not operating. The result is that he significantly underestimated demand on foreseeable peaks, such as have just occurred. The result is that the peak actually experienced in January of this year (in temperatures that were very close to the average coldest day each year over the last 30 years) is comparable to the forecasts of Mr. Miller for 2014 and 2019 identified in Exhibit C-20-21 at p.21. Presumably recognizing the unsatisfactory nature of that result, Mr. Miller adjusted his forecast in light of the weather immediately before the hearing commenced. Thus he now appears to acknowledge that there will, in fact, be a significant capacity shortfall (having denied this in the VIGP hearing and in his initial evidence in this proceeding) and concedes that with the benefit of the information available to him now, the gap will be in the order of 190 MW.[74] While the difference between BC Hydro's forecast and Mr. Miller's appears to have shrunk, BC Hydro's should continue to be preferred on the basis that the level of peaks experienced in January 2005 supports the level of the forecast. The design day temperature approach employed by BC Hydro was the subject of favourable comment in the VIGP Decision and events have borne it out. In short, BC Hydro believes that the standard of reliability it seeks to achieve in this regard is appropriate for a responsible utility.

CFT Criteria

55. Through the CFT process, BC Hydro sought a highly reliable resource. It wished to replace the HVDC system that had in excess of 97% availability—to replace "like for like."[75] BC Hydro determined that there were a number of technologies,

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[74] Exhibit C-20-37.

[75] T8: 1698/13-15.

including coal, gas and biomass, that could deliver this level of availability. It was therefore seen as an appropriate standard to include within the CFT.

56. BC Hydro acknowledges that establishing a high reliability standard did render some alternative energy sources, such as wind, solar and tidal, as being unable to compete. In this circumstance, those resources simply did not provide BC Hydro's resource needs on Vancouver Island. The particular requirements of the calls that BC Hydro may make for capacity or energy from time to time will make different projects more or less attractive. BC Hydro believes that it must be free to tailor its calls to meet its actual needs if ratepayer interests are to be best served.

57. The CFT criteria were heavily influenced by the Commission's VIGP decision. In that decision, the Commission reached a number of conclusions regarding electricity needs on the Island and told BC Hydro that in light of those conclusions, it was not yet persuaded that BC Hydro had identified the appropriate resource for the Island. Consequently, VIGP did not proceed.

58. BC Hydro accepts the Commission's jurisdiction to make the judgment it did. It has taken the Commission's determinations and, on the basis of them, designed a CFT process that seemed to it appropriate in light of those conclusions. Some key drivers of the CFT process design were the Commission's conclusions that there would indeed be a capacity gap in 2008 and that the gap should be filled with additional generation on the Island with a capacity amount of at least 150 MW. The Commission further concluded that demand side management should not be used as a means to close that basic gap.

59. BC Hydro respectfully submits that having assumed jurisdiction with respect to these matters, the Commission should follow through and accept the responsibility associated with that jurisdiction. That is, the VIGP decision set a course and it is very important that the Commission stay that course. The more the Commission is seen to exercise jurisdiction on the planning side, the more important it is that the Commission be seen not to second guess itself or those to whom it has given

direction. Thus, the analysis of the EPA should proceed by employing the conclusions and assumptions already identified in the VIGP Decision.

60. Not only had the Commission indicated its preference for support of some of the CFT criteria that some bidders now seek to put in issue, the bidders themselves were given and took advantage of every opportunity to comment on the terms. In an unprecedented move, BC Hydro provided bidders with its full evaluation model so each could determine how to optimize its bid. Thus, all participants went into the bidding process knowing precisely how their bid would be evaluated. Green Island Energy ("GIE"), Calpine and EPCOR all entered bids. NorskeCanada did not, but stayed in the process and did not formally withdraw as the CFT permitted it to do, but, rather, simply failed to submit a bid. There is no evidence that the CFT terms discouraged participation by bidders with projects meeting BC Hydro's needs.

61. Notwithstanding its full participation, GIE now raises some concerns with respect to the CFT. So too do some ratepayer groups. The most significant issues that have not been dealt with elsewhere were the term and the minimum portfolio size.

62. The CFT initially called for bidders to select a term of 10 to 25 years, but then settled on a fixed term of 25 years. This decision reflected the need to have a simple and straightforward basis for comparison of bids by requiring them all to be for the same term. BC Hydro further anticipated that most bidders would opt for a longer term to accommodate financing requirements. While power purchase agreements vary in their length, greenfield projects such as the DPP typically have terms of 20 to 30 years.[76] To reflect the potential difficulties of those who might have trouble making a 25-year commitment, BC Hydro relaxed other terms, such as fuel supply certainty requirements.

63. The minimum portfolio size reflected BC Hydro's understanding of the VIGP Decision and the January 23, 2004 letter from the Commission. While the

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[76] T8: 1851/25-26.

Commission calculated the shortfall in the winter of 2007/08 to be 115 MW, it acknowledged that a 150 MW minimum acquisition provided an appropriate cushion for planning purposes. Events subsequent to the VIGP Decision confirmed that the gap was growing, not shrinking. Accordingly, BC Hydro established a minimum portfolio of 150 MW, but designed a process that would permit it to keep bids from smaller projects if no cost-effective project emerged that met that requirement. This approach conferred a significant benefit on smaller projects by permitting them to be considered as part of a portfolio and by acknowledging no benefit to projects larger than 150 MW.

64. Further to this last point, BC Hydro recognized that an aggregation of small projects had an excellent opportunity to prevail based on the QEM methodology, and was surprised that the outcome was a VIGP Election.[77] The QEM originally conferred a transmission deferral credit of capacity in excess of 150 MW. When the credit was eliminated after the Commission's comments in its January 23, 2004 letter, the resulting simplified NPV analysis afforded portfolios at or near 150 MW an excellent opportunity to succeed.

Greenhouse Gas Emissions

65. Dr. Jaccard shared his views with respect to the potential for additional costs being imposed on different forms of generation as a result of attempts to control greenhouse gas emissions.[78] If Dr. Jaccard did nothing else, he provided graphic evidence of the challenges that any utility faces in determining the appropriate course for the future. What he did not do is provide evidence that is particularly helpful to the Commission in connection with this process.

66. Dr. Jaccard's thesis is that:

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[77] B-35, Direct Testimony of M. Hemmingsen, p. 10.

[78] C20-20.

(a) Canada's endorsement of the Kyoto Protocol will lead to some form of substantial tax or cost being imposed on gas-fired generation;[79]

(b) despite fairly uniform advice from economists, that tax will not be placed on the party burning it and creating the greenhouse gas emissions, but, rather, will be on the producer of the gas itself (sometimes referred to as a "carbon tax"); and[80]

(c) the EPA would not permit the form of tax to be passed through to DPP.

67. All these conditions are necessary prerequisites to his testimony having any relevance to this proceeding. That is, as Dr. Jaccard acknowledged, he is neither qualified to analyze, nor did he analyze, the allocation of responsibility for greenhouse gas costs as between BC Hydro and DPP.[81] BC Hydro's evidence that DPP is fully responsible for any such costs is uncontroverted and undisputed by DPP itself.[82]

68. Dr. Jaccard's only comment with respect to the allocation of risk is that one cannot rely on contracts in this regard. However, BC Hydro has built in a number of cushions to ensure it can do exactly that. First, it is entitled to $36 million as a deduction from the payment for the power to deal with any non-compliance by DPP. Also, the EPA and Lender Consent Agreement are designed to provide BC Hydro with the greatest possible protection and flexibility that contracts can offer against the risk of Seller insolvency for whatever reason. In particular, BC Hydro has letter of credit security, a subordinated charge on all project assets, step-in rights and rights of terminations, including termination of Seller insolvency.[83]

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[79] Evidence of Dr. Mark Jaccard.

[80] T14: 2939/24-2940/23; 2967/26-2971/24.

[81] T14: 2940/24-26; 2958/6-26.

[82] T10: 2242/23-2243/10.

[83] See also T7: 1388/13-1391/6 (Eckert testimony).

69. As to a "carbon tax" scenario, the fact is that most GHG policy options for industrial emitters being discussed in Canada and elsewhere are based on regulating or taxing emissions, not fuels. Although that was not the focus of this proceeding, there are some references in the evidence. For example, an excerpt from BC Hydro's 2004 Annual Report, tendered into evidence by NorskeCanada, discusses how several of BC Hydro's thermal stations meet the federal definition of "a large final emitter of greenhouse gases . . . and will be covered by federal emissions reduction standards."[84] The Report goes on to note that:

> Large final emitters will have access to a domestic emissions trading system and offsets derived from emission reduction projects not covered by regulations. [T]his increased clarity means that risk around this issue has been reduced.

70. DPP's witnesses also testified as to their direct participation in consultation meetings with senior Natural Resources Canada officials and the large "final emitters groups" of the Canadian electricity sector.[85]

71. In a similar vein, Dr. Bramley, expert witness for GSX CCC in the VIGP proceeding, testified that emissions pricing is the expected result of the Kyoto Protocol:

> Governments throughout the industrialized world have settled on emissions pricing, implemented through emissions trading systems, as the method of choice to control GHG emissions from large industrial facilities.
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> . . . .
>
> The *Climate Change Plan for Canada*, the federal government's plan for implementation of the Kyoto Protocol, states that industrial facilities emitting large quantities of GHGs . . . will be subject to a "covenants and emissions trading system." The government is now moving ahead quickly with the elaboration of this system through a new Large Industrial Users Group . . . The federal government will negotiate GHG emissions targets with large industrial companies . . . . These targets will be enshrined in negotiated, legally binding

[84] C2-11 (attaching BC Hydro 2004 Annual Report on Performance—see p. 27).
[85] T10: 2244/2-6.

> agreements called covenants, which can be expected to specify penalties for failing to meet targets. *Targets are likely typically to be expressed in terms of GHG intensity (emissions per unit of production.)*[86]

The testimony has been incorporated into the record of this proceeding at the request of GSX CCC.

72. Dr. Bramley goes on to explain that companies will be able to combine three or four emissions-based ways of meeting their targets, and that this domestic emission trading (DET) system will likely link to an international emissions trading market.[87]

73. The contradictory nature of GSX CCC's own expert policy witnesses on this point illustrates how inappropriate it would be to evaluate capacity resources on the basis of potential greenhouse gas liabilities. Not only would it be speculative to assume that such liabilities will be imposed, it would layer speculation on speculation to assume that these costs would be implemented by way of a fuel-based carbon tax, rather than at the emitter level, and that if they were, the EPA would require BC Hydro, not DPP, to pay for them.

Treatment of Payment Under the VTA

74. BC Hydro provided a credit to those bidders who were prepared to purchase the VIGP assets for $50 million.[88] For those bids which did not require the VIGP assets, BC Hydro assumed that it would be free to sell them and obtain a salvage value of

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[86] VIGP Exhibit 19B, Evidence of Matthew Bramley: *Future Financial Liability for Greenhouse Gas Emissions from the Vancouver Island Generation Project*, pp. 3-6 (emphasis added; citations omitted). (See Exhibit C-20-30, requesting admission of Dr. Bramley's evidence in this proceeding).

[87] Id. at pp. 6-7. The Kyoto Protocol sets targets for individual countries' emissions, but allows those targets to be met via three international emissions trading mechanisms, thereby creating an international emissions trading market. Within countries, governments can similarly set GHG emission targets for individual industrial emitters, but allow those targets to be met through DET systems in emissions rights.

[88] B-9: p.4-5, BC Hydro response to BCUC staff IR 1.16.2.

$14 million.[89] Some intervenors, particularly the CEC through Mr. Craig, sought to make an issue of that treatment.

75. This issue arose in the context of the CFT process itself. BC Hydro explained there in response to question 118[90] that the $50 million credit properly reflected the value of a bid that provided this payment compared to one which did not. Mr. Craig's contrary analysis was that he assumed BC Hydro was transferring the value it currently carried on its books as represented by the assets to bidders purchasing them without reflecting the loss of value that would result from that transfer.[91] The flaw in this reasoning is that BC Hydro has already taken a provision for the full value of the assets and so they are not being carried on its books with a positive value at the moment. What is really happening is that the deferral account in which there is currently $67 million[92] or thereabouts on account of VIGP costs will be reduced to $17 million.[93] This reduces the exposure that ratepayers have to the potential for recovering these costs in future rates. Thus, it is entirely appropriate that the credit be provided in the way that it has.

NorskeCanada Demand Management Proposal (NCDMP)

76. The NCDMP offers 140 MW from Elk Falls or 70 MW from Crofton. It does not offer both without further development.[94] Thus, its maximum capacity as currently offered is 140 MW. NorskeCanada acknowledged that its proposal was not a CFT bid.[95] It was not for on-Island generation, which is what the Commission had

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[89] *Id.*

[90] B-61.

[91] T7: T1530/19-T1540/13.

[92] T7: 1636/23-24.

[93] T7: 1515/13-20.

[94] C2-3, p.20.

[95] T10: 2441/9-2443/4.

determined was the next appropriate resource to meet Island electricity needs.[96] Thus, the NCDMP does not qualify to resolve the capacity shortfall anticipated in 2007/08. Nevertheless, it suggests NCDMP can be part of the solution. BC Hydro does not accept this.

77. In any event, the NCDMP does not meet the N-1 planning criterion and neither BCTC nor BC Hydro believes it can at this time.[97] Both organizations believe it is very useful to meet N-2 conditions and appreciate NorskeCanada's willingness to assist in that regard. However, the fact remains that NCDMP does not provide reliable capacity on Vancouver Island.

78. Because the NCDMP was not bid into the CFT, and given both the anti-lobbying provisions in the CFT process, it would have been inappropriate for BC Hydro to rely on the NCDMP proposal during the CFT process.[98] It would not be appropriate to do so now.

Cost-Effectiveness

Definition of the Portfolios

79. The Commission has identified as a central issue in this proceeding the cost-effectiveness of the CFT outcome when compared with potential Tier 1 or No Award solutions.[99] BC Hydro submits that the cost-effectiveness of Tier 1 has been amply demonstrated by the record of this proceeding.

80. Consideration of the relative cost-effectiveness of Tier 1, Tier 2 and the No Award portfolios has to be undertaken in two steps. First, each of the portfolios has to be

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[96] VIGP Decision, p.78; B-1, Appendix F.

[97] C2-9, BCTC Evaluation of NorskeCanada DM Proposal, p.4; C2-11, Exploring Vancouver Island's Energy Future; T9: 1974/1-11, 1977/17-25.

[98] T7: 1366/5-15.

[99] T2: 313/24-314/1.

defined. Only then can they be compared. The evidence during the hearing made clear that there is considerable debate about what each tier looks like. Each is discussed in turn.

Tier 1

81. The only issue concerning the definition of Tier 1 is whether it should include duct firing. As set out in the early part of this Argument, the Tier 1 portfolio should be assumed to contain duct firing because that is what the EPA requires to be built, but BC Hydro should not be assumed to purchase the additional output duct firing it makes possible.

Tier 2

82. BC Hydro has defined Tier 2 as the sum of the two bids it could have accepted from the CFT process totalling 122 MW and comprising GIE and the Ladysmith peaker, plus the load curtailment and temporary generation BC Hydro would need to acquire to meet its capacity needs. BC Hydro's approach is predicated on the assumption that proponents that could not or did not bid their projects into the CFT process cannot be reliably included in Tier 2.

83. GIE takes a radically different approach. It asked the Commission to suspend the results of the CFT process and ignore the behaviour of the participants in it. It invites the Commission to assemble hypothetical Tier 2 portfolios consisting of bids that were tendered with a condition permitting termination if a landlord declined to extend the bidder's lease (Calpine) or were deficient for other reasons (a second peaker) or were not bids at all because they did not take the form of generation on Vancouver Island (NCDMP).[100] BC Hydro rejects the Tier 2 that GIE seeks to create on the basis that it bears no relation to the CFT process or the VIGP Decision that sponsored it.

[100] BC Hydro also uses NCDMP as part of its Tier 2 option, despite its shortcomings in terms of meeting planning criteria.

84. GIE's approach subverts the intention of the Tier 2 and No Award categories contemplated in the CFT process. Section 17.3 of the CFT, which was introduced by addendum after the process was initiated, grants to BC Hydro a discretion. It affords BC Hydro the right, *but not the obligation*, to award one or more contracts aggregating less than 150 MW where senior management concludes, in their discretion, that the so-called Tier 1 outcome is not cost-effective. This discretionary right was introduced without obligation to afford BC Hydro management the flexibility it needed to protect ratepayers, not bidders, and so that BC Hydro could salvage value from the CFT by accepting tenders not exceeding 150 MW in the aggregate if it became evident that the so-called Tier 1 outcome was simply not cost-effective. This section does not introduce an obligation on BC Hydro to exercise that discretion, for an obligation would be inconsistent with discretion. BC Hydro management carefully considered the question of whether or not the exercise of this discretionary right was warranted. It concluded, taking into account the analysis available to it, that the discretion should not be exercised, and that the Tier 1 outcome should be confirmed.

85. GIE now wishes to take a contractual "out" that BC Hydro reserved to itself, but did not employ, and elevate the provision to an obligation of BC Hydro operating in GIE's favour. This it cannot do. Moving to a Tier 2 bid or, indeed, making no award at all was a right, but not an obligation, of BC Hydro.

86. GIE's evidence presumes the Commission should substitute its judgment for that of BC Hydro in connection with moving to Tier 2 or No Award. BC Hydro believes the assessment it performed in this regard is amply affirmed by both the cost-effectiveness study and consideration of reliability issues that appears as Exhibit B-54. Both from a straight NPV perspective and from the perspective of system reliability as a whole, the evidence is that the DPP solution is an attractive one, particularly in light of the greater gap now apparent on Vancouver Island once the HVDC system can no longer be relied on. In these circumstances, there is no basis for the Commission reassessing the issue. Moreover, GIE's attempts to demonstrate the contrary are flawed in at least two fundamental respects.

87. The perils of the Commission substituting its judgment into the CFT process based on what might have been, as opposed to what was, is amply demonstrated by the history of the Calpine bid in this process.

88. Calpine submitted a bid that claimed a right to terminate if Calpine could not extend its leasehold terms. BC Hydro declined to waive this material non-compliant requirement.

89. In addition, it is a false premise to assume that if BC Hydro had accepted the bid, Calpine would somehow have been included within a winning portfolio. The evidence is to the contrary. While it is true that the bid was rejected because it contained a material condition (as acknowledged by Calpine), it would have been rejected in any event. The Independent Reviewer makes this clear in its fourth report where it indicates that the tender security accompanying the Calpine bid was inadequate.[101] Accordingly, GIE can find no comfort in the Calpine bid and has no basis for including the Calpine project in any of the scenarios that it attempts to develop in its evidence.

90. It is useful to recall that the purpose of the CFT was to allow would-be generators on Vancouver Island to establish that the costs of the projects "can be confirmed near their expected values."[102] Calpine has been given every opportunity to come forward and confirm precisely that in the context of the CFT. It could have intervened in the process or it could have allowed GIE to tender evidence on its behalf. GIE could not have made clearer its willingness to cooperate with Calpine in this regard. GIE went so far as to successfully persuade the Commission to leave the record open for an extra 48 hours to accommodate a last-minute filing from Calpine. Nothing was forthcoming. Calpine's decision not to participate in the process leaves the Commission and all parties to this proceeding no further ahead with respect to the true costs at which it would be prepared to provide capacity on

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[101] B-1, Appendix K-4, p.13; B-74.

[102] VIGP Decision, p. 78.

Vancouver Island. This highlights the danger of substituting rumour for fact and underscores BC Hydro's insistence on relying on compliant bids to meet its capacity needs on Vancouver Island.

No Award

91. The No Award scenario considered by BC Hydro recognizes that in the absence of any accepted bids, BC Hydro would have no option but to undertake a contingency plan to meet a looming capacity shortfall. This would again comprise NCDMP and sufficient peakers to meet the shortfall.

92. GIE does not dwell on a No Award outcome. However, NorskeCanada and JIESC do, and in their evidence suggest that NCDMP, coupled with unspecified other resources, could offer a solution. It is not clear that the solution being proposed differs from what BC Hydro has considered in its cost-effectiveness analysis, so no further consideration need be given to that issue here.

Comparison of the Portfolios

93. BC Hydro compared the outcome of the CFT process against three alternative solutions to Vancouver Island's capacity needs. First, it compared the cost of the EPA to the VIGP benchmark cost as required by the VIGP Decision. Second, it compared the EPA to the Tier 2 and No Award portfolios it developed.

94. Tier 1 compared favourably to the VIGP benchmark on the basis of cost. Taking into account the $50 million payment to be received under the VTA, the present value cost of the EPA is approximately $100 million less than the cost of the VIGP benchmark. Accordingly, BC Hydro is confident that the EPA will result in substantial savings for ratepayers relative to the VIGP alternative.

95. The cost-effectiveness analysis, as presented in Attachment A to Appendix J of Exhibit B-1 and updated by way of undertaking,[103] makes it clear that from a quantitative perspective, the expected value of the CFT outcome is also expected to be more beneficial for ratepayers than either Tier 2 or No Award. It is important to recall that this outcome occurs even if the Duke Point plant recovers only 62.5% of its capital cost. As explained above, this is a conservative assumption.

96. Appendix J of Exhibit B-1 presents a quantitative comparison of Tier 1, Tier 2 and the No Award scenario on a net present value basis. It demonstrates that in expected conditions, Tier 1 will prove to be the most cost-effective of the three options to ensure reliable service on Vancouver Island. The analysis presented in Appendix J permits comparison of the alternative portfolios by equalizing the energy and capacity of each portfolio. At the Commission's request in BCUC IR 2.73.1, BC Hydro also compared the portfolios on the basis that capacity only was equalized. Both analyses indicate Tier 1 is the preferred portfolio.

97. With respect to GIE's filed evidence and its conclusion that the Tier 2 portfolio has lower NPV than Tier 1, BC Hydro notes that GIE's approach fails to incorporate two important elements in order for its results to provide meaningful comparison among various CFT scenarios. First, none of the portfolios contained in GIE's evidence provide enough capacity to meet the forecast capacity shortfall. The highest capacity its portfolio provides is Portfolio 2A, which offers 252 MW for two years, which is not sufficient to meet the forecast capacity shortfall in F2008 (the other three proposed portfolios have capacity of 122 MW, 169 MW and 170 MW, respectively). Second, it is inappropriate to compare the QEM-generated NPV of portfolios that have different capacity in the context of cost-effectiveness analysis. In that analysis, the additional capacity the 252 MW Tier 1 portfolio provides over the 122 MW Tier 2 portfolio has value not only in assisting BC Hydro in meeting the load deficit, but also has capacity value to the Island and to the system as a whole. BC Hydro submits that system benefits provided by Tier 1 can be properly evaluated via equalization of

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[103] B-99.

energy and capacity (Appendix J of the CFT Report), or capacity only (BCUC IR 2.73.1), for the duration of the Term.

98. BC Hydro submits that if relevant adjustments mentioned above were made to GIE's analysis, the results would be consistent with BC Hydro's cost-effectiveness analysis (Appendix J of the CFT Report) and Response to BCUC IR 2.73.1, which shows Tier 1 as the most cost-effective portfolio. In addition to this quantitative conclusion, from a qualitative perspective, the Tier 1 proposal is ranked ahead of Tier 2 and No Award from the perspective of reliability and other subjective factors.[104]

99. The Tier 1 proposal introduces a gas supply risk that has been discussed at length above. However, from a system portfolio perspective, BC Hydro is much less exposed to gas supply than most other utilities, and as Ms. Van Ruyven testified, adding an element of exposure to gas supply risk as part of an overall portfolio may be no bad thing. That is, BC Hydro looks at its fleet of resources available to meet load and, from that perspective, having an additional gas resource can be desirable.

100. The specific features of the DPP plant, when compared with the No Award and Tier 2 solutions, are discussed in Exhibit B-54, which makes clear that when taken as a whole, there are substantial benefits to the Tier 1 solution.

101. With respect to the reliability analysis contained in GIE's evidence, BC Hydro submits that the analysis and the conclusion should not be accepted because to be considered N-1 compliant, the generation and the transmission options have to be available almost all of the time and that N-1 and N-2 contingency events may not coincide with peak-demand days. BC Hydro notes that in GIE's portfolio 2A, only 122 MW of the portfolio is available most of the time (the other 130 MW is from NCDMP, which has utilization limitations and does not meet the N-1 criteria).

102. It is also important to note that the Tier 1 solution likely imposes the least ratepayer impact. The levelized impact of the Duke Power project is less than the No Award

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[104] B-54.

solution. The payment of $50 million in connection with the Tier 1 solution potentially provides immediate benefits to ratepayers by reducing the VIGP/GSX deferral account, and thus the prospect of recovering those amounts in rates. This should reduce the rate impact of Tier 1 below that of Tier 2. In any event, as can be seen from BC Hydro's response to BCOAPO IR 1.18.1, the difference in levelized cost of energy for all three scenarios over the contract life in the context of the system as a whole is insignificant.[105]

103. In the short term, the No Award solution has a significantly greater rate impact than either the Tier 2 or DPP solution. Thus, the No Award approach requires ratepayers to absorb these impacts in the hope that in the longer run, those impacts will come down. That is not a risk that BC Hydro believes is warranted.

104. Indeed, the No Award scenario will have greater short-term impacts on rates than the DPP solution in any foreseeable circumstance. Gains for ratepayers would only result from No Award if:

(a) there is not a first contingency event prior to a transmission line being completed;

(b) energy markets are significantly adverse to gas plants in the future; and

[105] The levelized costs in BCOAPO IR 1.18.1 appear to show that the No Award case has the lowest impact on electricity rates over the long term, which is inconsistent with the cost-effective analysis in Appendix J of the CFT Report, showing that Tier 1 is more cost-effective for the ratepayer than the No Award scenario. The reason for the inconsistency is that the costs in BCOAPO IR 1.18.1 do not take into account: (i) the $50 million credit for Tier 1 (the cash payment from DPP for the VIGP assets) relative to the $14 million credit for Tier 2 and No Award (the salvage value of the VIGP assets); (ii) the Network Upgrade Effects adder ($9.3 million credit for Tier 1, $10.3 million cost for Tier 2, $0 cost for No Award); and (iii) the $20 million credit for Tier 1 and the $11 million credit for Tier 2 for deferring the second 230 kV cable relative to No Award. Note that items (i) and (ii) were portfolio adjustments in the QEM, and this specific information has been previously provided in confidence to the Commission in response to BCUC IR 1.9.3. Item (iii) is a deferral credit that was applied in the cost-effective analysis in Appendix J, and again, this information has been previously provided in confidence to the Commission in response to BCUC IR 1.14.4. If these three effects are taken into account in the computation of the levelized costs in BCOAPO IR 1.18.1, the levelized cost for the T1 case would be lower than the levelized costs of the other two cases, consistent with the results for the base case scenario in Appendix J (cable in-service of October 2009, 261 MW deficit in 2007/08, 100% cost assumption for Mainland energy backfill).

(c) the ongoing work between BC Hydro, BCTC and NorskeCanada confirms that the NorskeCanada proposal can be implemented in an acceptable way.

105. If all three of these events occur, it might be possible to accomplish a minor reduction in the rate impact of the Vancouver Island solution over the long term. BC Hydro considers that this speculative and marginal rate advantage does not warrant the risks associated with trying to obtain it.

106. These comments allow a broader observation. The range of possible outcomes for future rates suggests that concern for ratepayer impacts in this proceeding may be overstated. Additions to capacity, whether in the form of demand side management and temporary generators or permanent solutions, such as those proposed in the EPA or some hybrid as contained in Tier 1, all impose an upward pressure on rates. That is simply a feature of adding capacity to a very low cost system. The range of rate impacts associated with the constellation of solutions that are available is not that great. Whichever solution is ultimately adopted, it will be difficult to say, even with the benefit of hindsight, that the chosen solution was demonstrably better or worse than other solutions that might have been selected. The only circumstance in which a solution will be demonstrated to have been inadequate is if it fails to meet the reliability requirements of Vancouver Island customers at some point in the future. BC Hydro believes that as long as the solution being put forward in the EPA appears to the Commission to provide reliable supply at a cost within the range of those solutions that are generally acceptable, the Commission should not interfere with the EPA.

Summary and Conclusion

107. At the outset of the Argument, it was suggested this was an unusual hearing. It was also a challenging one. The position of parties with respect to a natural gas-fired plant on Vancouver Island appears to have become so entrenched that a debate grounded in its merits is difficult.

108. Part of the difficulty may be no more than the inevitable controversy that arises when a specific project is brought forward as a solution. That is, it is as easy to downplay the challenges with projects just over the horizon as it is to overplay those that are receiving immediate attention.

109. In the case of the CFT process, there appears to have been even more than that at work. Perhaps the intensity of regulatory process in general in British Columbia and with respect to BC Hydro in particular has heightened sensitivities. As well, the association between VIGP and the now abandoned GSX project has burdened any Vancouver Island gas-fired plant with additional associations, whether they continue to be relevant or not. Whatever the explanation, the strong feelings associated with the project make a balanced assessment difficult.

110. Despite these difficulties, the Commission's task is to perform just that assessment in determining whether the public interest requires it to interfere with the EPA between BC Hydro and DPP. For the reasons outlined in this Argument and based on the extensive record that the Commission has before it, BC Hydro respectfully submits that a dispassionate assessment can only lead to the conclusion that a reliable solution to Vancouver Island's long-standing capacity needs is at hand and the parties to the EPA should be permitted to proceed with the contract in accordance with its terms.

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 1st day of February, 2005

LAWSON LUNDELL

per Chris W. Sanderson, QC   *per* John C. Kleefeld   *per* Heather M. Cane