BC’s Electricity Options:  
Multi-Attribute Trade-Off and Risk Analysis of the Natural  
Gas Strategy for Vancouver Island  

Postscript to the Report  
of May 1, 2002  

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Rationale for this Postscript

We issued a report on May 1, 2002 entitled, **BC’s Electricity Options: Multi-Attribute Trade-Off and Risk Analysis of the Natural Gas Strategy for Vancouver Island**. Since that report, we have become aware of four issues that invite additional clarification and additional analysis. In this postscript, we report on our recent efforts in this regard. To ensure that this further analysis is not taken out of context, this Postscript should be attached as an addendum or appendix to our original report of May 1, 2002.

The four issues are the following.

- BC Hydro spokespersons have argued publicly that its GSX-CCGT strategy is the outcome of Hydro’s stakeholder trade-off analysis conducted during the production of the 1995 Integrated Electricity Plan.\(^1\)

- BC Hydro spokespersons have argued that the 7th spare phase cable option for the 500 kv circuits is no longer the best option for investing in sustained or expanded electricity transmission to Vancouver Island (VI) and the now-preferred alternative is investment in the 230 kv circuit, which has a higher capital cost than the value used in our analysis.

- BC Hydro has issued a request for proposals (RFP) for 800 GWhs of independent power production (IPP) with 4.9 c/kWh as a price ceiling, presumably based on Hydro’s estimated long-run cost of production from new CCGT facilities, but Hydro has also revised upward its capital cost estimate for the Nanaimo CCGT plant. In our analysis reported on May 1, we used a generic unit cost estimate for a CCGT plant, but here we use the new capital cost numbers and recent industry natural gas price forecasts to generate an estimated cost of the plant.

- Independent experts have suggested that GSX-CCGT will function often as a peaking plant, especially in its early years, because of the low operating costs of competing facilities to provide baseload service to VI. This would also lead to higher estimates for unit costs, meaning that Hydro should be offering a much higher RFP price ceiling for IPP-based, firm, peak electricity or other peak actions (efficiency, load shifting, interruptible) that could delay or supplant GSX-CCGT.

The 1995 IEP and Possible Stakeholder Support for GSX-CCGT

BC Hydro spokespersons have presented publicly an argument that is roughly the following.

The 1995 consultative process supported Burrard repowering and two cogeneration plants on VI. This preference for natural gas generation as a whole

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\(^1\) In this postscript we use the same acronyms as in our original report: combined cycle gas turbine = CCGT; Georgia Strait Crossing = GSX; low emission independent power producers portfolio = LOW-EM-IPP portfolio.
(as exemplified by acceptance of Burrard) and for natural gas-based cogeneration plants on VI shows that the current GSX-CCGT strategy would have been supported by the consultative committee.

The wording of the 1995 IEP does not, however, support this inference by Hydro spokespersons.

The consultative committee did not reach consensus and therefore produced two different portfolios: F1 and F2F. This lack of consensus means that it is misleading to say that anything Hydro is pursuing today might represent what the entire consultative committee would have supported. Page 6-19 of the IEP summarizes the differences between the two portfolios. F2F has many similarities to the low emission proposal, LOW-EM-IPP, that we have produced in contrast to BC Hydro's GSX-CCGT strategy – in terms of resources, costs and emissions. It calls for retirement of three of Burrard's units, the development of 550 MW of alternative technologies, and additional small to medium hydro projects if required.

In any case, BC Hydro adopted neither portfolio put forward by the stakeholders, instead producing its own plan, which overlapped to some extent with both F1 and F2F but also differed in various ways. Thus, BC Hydro’s 1995 IEP represents the view of BC Hydro’s management and board, presumably taking into account the views of stakeholders. This 1995 IEP was neither tested nor approved by the BC Utilities Commission.

Both F1 and F2F do not mention a second natural gas pipeline. In fact, F1, F2F and even BC Hydro’s plan only refer to three options to meet VI capacity growth needs and the cable retirement problem (p.7-9): (1) 7th cable on 500 kv circuits, (2) new HVDC system, and (3) investment in the 230 kv circuit from Arnott to Sahtlam. Of these, the 7th cable option was selected by Hydro.

Any of these three approaches to serving Vancouver Island differs dramatically from the 2000 IEP with its call for a second natural gas pipeline with one or more large, stand-alone (not cogeneration) CCGT plants. The 1995 IEP provides no evidence of support for this new direction from the entire consultative committee, or a subgroup of that committee, or even BC Hydro’s management.

**Emergence of 230 kv Circuit as Hydro’s Preferred Option for Cable Replacement**

Since our original report, BC Hydro has publicly stated that, if it were to invest in undersea cables for capacity provision to VI, it now believes that investment in the 230 kv circuit is the best option. Hydro further claims that the capital cost of this project is about $100 million more than the capital cost of GSX. This would change our estimates in the original report for the cost of LOW-EM-IPP.

We input the new capital cost figures into our discounted cash flow analysis and have generated a new estimate for the cost of LOW-EM-IPP. The unit cost of LOW-EM-IPP increases from 6.57 c/kWh to 6.71 c/kWh. However, because LOW-EM-IPP represents
such a small percentage of BC Hydro’s total cost of production, the effect on rates remains negligible. In our original calculation, LOW-EM-IPP resulted in each residential customer paying an extra $3.40 per year, or 28 cents/month. With these new capital cost estimates, each residential customer would pay an extra $4.10 per year, or 34 cents/month.

Our base case analysis is still in question, however, because of Hydro’s recently revised capital cost estimate for its proposed CCGT plant at Nanaimo, and new estimates of plant efficiency, non-energy operating costs, plant operation rates and gas price forecasts. We explore this below.

The Nanaimo CCGT Plant as an Indicator of Long-Run Electricity Supply Cost on VI

In our analysis reported on May 1, we assumed a generic unit cost for a CCGT plant of 5.3 ¢/kWh. Since then, Hydro’s capital cost estimate for the 265 MW Nanaimo plant has increased to $370 million, market forecasts of long-run natural gas prices have increased, and IPPs have pointed out that a fair comparison of a public monopoly investment with an IPP investment requires comparable treatment in terms of the cost of capital (discount rate, debt equity ratio) and other factors.

Table 1 provides our new assumptions and the resulting electricity cost estimate for the Nanaimo CCGT. It includes the capital cost of $370 million, non-energy operating cost of $7.5/MWh, a long range natural gas price forecast of $5.5/GJ, a use rate of 8300 hours/year (95% load factor), and a discount rate of 9.5% to reflect a weighted cost of equity and debt capital. A portion of the capital cost of GSX - $143 million out a total of $260 million – was used to reflect the cost of gas delivery. Any additional transmission costs associated with transporting the gas on the existing Centra Gas pipeline from the end of the GSX pipeline to Nanaimo were not included.

Table 1: Analysis of Proposed Nanaimo CCGT, Assumptions and Result

<table>
<thead>
<tr>
<th>Assumptions</th>
<th>2001 Canadian ($)</th>
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</thead>
<tbody>
<tr>
<td>Capital Cost of CCGT (million $)</td>
<td>370</td>
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<tr>
<td>Non-energy Operating Cost ($/MWh)</td>
<td>7.5</td>
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<tr>
<td>Natural Gas Price ($/GJ)</td>
<td>5.5</td>
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<tr>
<td>Use Rate (hours/year)</td>
<td>8300</td>
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<tr>
<td>Portion of GSX Capital Cost (million $)</td>
<td>143</td>
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<tr>
<td>Discount Rate (%)</td>
<td>9.5</td>
</tr>
<tr>
<td>Heat Rate of CCGT (GJ/MWh)</td>
<td>7.4</td>
</tr>
<tr>
<td>Result: Unit Electricity Cost (¢/kWh)</td>
<td>7.16</td>
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</tbody>
</table>

While BC Hydro may be able to use provincial debt guarantees to borrow money at a lower rate and conceivably use 100% debt financing, this is not a fair comparison with the relative merits of IPP investment. BC Hydro’s cost of capital does not incorporate the risk of such an investment whereas private costs of capital (debt and equity) must fully reflect risk.
Our method of allocating the capital cost of GSX to CCGT generation on Vancouver Island was somewhat different from the initial study. In the initial study, we assumed that three 220 MW CCGT plants would be constructed to eventually account for all of the GSX gas (hence the full capital cost of GSX was absorbed by CCGT generation). In the current calculation, we assumed that about 40 per cent of the GSX capital cost would always apply to the Nanaimo CCGT. We also attributed a share of the remaining capital cost until about 2012, based on assumptions about the timing of future plants and the growth of non-electricity natural gas demand.

Given the assumptions described above, we generated a unit cost of electricity from the Nanaimo CCGT of 7.16 ¢/kWh. If this cost is indicative of BC Hydro’s effective long run supply cost for electricity on VI, Hydro could issue a RFP to IPPs on VI using a much higher ceiling than the 4.9 ¢/kWh in its recent RFP and save provincial ratepayers money from any legitimate IPP supply that is forthcoming in response.

**Cost Estimates if the Nanaimo CCGT Functions Initially as a Peaking Facility**

BC Hydro argues that the Nanaimo CCGT is required to ensure that VI does not suffer brownouts during peak demand periods. This risk becomes pronounced by 2004/2005 according to Hydro’s load growth forecast. Some experts have suggested that the Nanaimo CCGT will function primarily as a peaking plant in its early years because of the low operating costs of the other facilities available to supply energy to VI, and the hydropower available to the entire BC system during normal and high water years.

Electricity supply to VI in future will be provided primarily by 450 MW of on-island hydropower generation, 240 MW from Island Cogeneration at Elk Falls and 1200 MW of mainland supply via the 500 kv circuit. The operating cost of these sources is generally lower than the natural gas operating cost of a CCGT plant. It appears, therefore, that the CCGT plant will only be competitive on VI during times when demand capacity exceeds this supply capacity. Unless Island Cogeneration can use its fuel switching capability, its peaking capacity is considered to be 125 MW, so the total peaking capacity would be 1775 MW. Peak on VI is rising toward 2000 MW and should surpass this significantly be the end of the decade.

However, CCGT capacity on VI can also serve the growing need for more electricity throughout the BC system. As electricity demand increases in mainland BC, less would be transmitted to VI via the 500 kv circuits, with the Nanaimo-CCGT, and subsequent plants, making up the difference. But because the BC system is dominated by hydropower, the energy capability of the system in high water years and perhaps even normal water years can be in excess of domestic demand. In some of these circumstances, a natural gas-fired CCGT plant has less likelihood of being operated.

This analysis is further complicated by BC’s interconnection with other systems. If BC were isolated from other regions, it is fairly safe to say that under normal and high water conditions the Nanaimo CCGT would not run as a baseload plant. However, the opportunity to export power and to store power in hydro reservoirs complicates the
analysis. There may be opportunities for BC Hydro to run its Nanaimo CCGT plant during (1) off-peak periods in order to store water for export sale during peak periods and (2) any time that the margin of electricity prices over natural gas prices is substantially larger in BC than in neighbouring jurisdictions into which we could export electricity.

For illustrative purposes, we explore a scenario in which the Nanaimo CCGT plant is used primarily for peaking in its early years and then shifts to full operation by 2010. In this scenario, the discounted average capacity utilization of the plant over a 20 year period is only 75%. If this is the case, the substitution of 6570 hours into our calculation leads to a cost of 7.78 ¢/kWh for power from the Nanaimo CCGT.

A prudent investment strategy by the government and/or BC Hydro would be to test the ability of external sources to address VI’s peak capacity needs and eventually BC’s energy generation needs at perhaps a substantially lower cost. BC Hydro could issue a RFP for peak power on VI and offer to pay up to 7.5 ¢/kWh for solutions.

The response to the RFP, which could be large, might include peak electricity efficiency, peak electricity load shifting, peak natural gas efficiency or load shifting in order to free up firm gas transmission for the Island Cogeneration plant (increasing its firm from 125 MW to 240 MW), electricity or natural gas interruptible, any alternative energy source that can guarantee peak output (some small hydro and some woodwaste) and cogeneration of electricity from the small industrial, commercial and institutional users of natural gas on VI. This latter source may be especially attractive because the firm peak demand for natural gas for these customers is coincident with the firm peak electricity demand. In other words, a great deal of natural gas is currently being burned on VI from the existing pipeline, yet almost none of the waste heat from this gas combustion (except Island Cogeneration) is being used to produce the peak electricity that VI needs, even though that combustion occurs at the exact time that the electricity is needed.3

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3 As an interesting contrast, in the past 15 years, IPPs in the Netherlands have installed over 1,500 MW of small-scale cogeneration from natural gas combustion (all by micro-generation units of less than 1 MW) in the small industry, commercial, agricultural and institutional sectors. See Strachan and Dowlatbadi (2002) “Distributed generation and distributed utilities,” *Energy Policy*, V.30:649-661.