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

Final Report

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Executive Summary

BC Hydro’s Integrated Electricity Plan (IEP) for 2000 is dominated by one or several combined cycle gas turbine plants (CCGT) on Vancouver Island, fed by a new natural gas pipeline called the Georgia Strait Crossing (GSX). The proposed pipeline would provide transport from the Sumas / Huntingdon supply hub in Washington State, connecting with the existing Centra Gas transmission system on the Island. For convenience, we refer to the strategy outlined above as GSX-CCGT.

We are concerned about GSX-CCGT because the 2000 IEP does not contain all of the necessary elements of multi-attribute trade-off analysis (MATA) – a tool commonly used by electric utilities to evaluate alternative generation and end-use efficiency investments in terms of their financial, environmental and social attributes. The IEP did not consider a full range of options, there was no public involvement in order to assess values about intangible factors and trade-offs, and an explicit risk analysis was not performed. We therefore conducted our own simple MATA to address some of the important issues we feel were overlooked in BC Hydro’s latest planning process. By making this report available to the public, we hope to foster a broader public discussion about British Columbia’s electricity options.

We have developed a contrasting alternative to GSX-CCGT that involves a province-wide portfolio of electricity investments in low emission generation capacity by Independent Power Producers (IPPs). We refer to this option as LOW-EM-IPP. Transmission capacity to VI is increased and IPPs are encouraged to develop cogeneration, woodwaste and small-medium hydro resources throughout the province. These generation options have positive environmental attributes and are low in cost relative to other environmentally desirable technologies.

We evaluated the two portfolios on the basis of a series of attributes including unit electricity costs, impact on residential electricity rates, magnitude of CO\textsubscript{2}e and NO\textsubscript{x} emissions, electricity security on VI and job creation. We also calculated the cost of CO\textsubscript{2}e emission reduction. Because several highly uncertain parameters are involved, we conducted an analysis of the financial cost risks associated with both GSX-CCGT and LOW-EM-IPP.

Base Case Assumptions

In order to conduct our analysis, we used the available data and literature (primarily from BC Hydro), as well as expert opinion to derive base case assumptions for GSX-CCGT and LOW-EM-IPP. These assumptions are summarized in Table ES-1. Our base case GSX-CCGT portfolio includes three 220 MW CCGT facilities built in stages on VI, with the first one in-service in fiscal year 04/05, the second in 06/07 and the third in 09/10. Each CCGT produces 1,760 GWh / year, resulting in 5,280 GWh generated in 09/10.

\footnote{The common electricity industry name for its application of MATA is integrated resource planning (IRP).}
Table ES-1: Summary of GSX-CCGT and LOW-EM-IPP Base Case Assumptions

<table>
<thead>
<tr>
<th></th>
<th>04/05</th>
<th>06/07</th>
<th>09/10</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>GSX-CCGT</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of CCGTs on VI</td>
<td>1</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>Total CCGT Capacity (MW)</td>
<td>220</td>
<td>440</td>
<td>660</td>
</tr>
<tr>
<td>Generation (GWh)</td>
<td>1,760</td>
<td>3,520</td>
<td>5,280</td>
</tr>
<tr>
<td>CCGT Generation Cost (¢ / kWh)</td>
<td>5.3</td>
<td>5.3</td>
<td>5.3</td>
</tr>
<tr>
<td>Capital Cost of GSX</td>
<td>260</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>(million 2001 Cdn $, undiscounted)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>LOW-EM-IPP</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generation (GWh)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>(7% added for transmission losses)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cogeneration</td>
<td>628</td>
<td>1,255</td>
<td>1,883</td>
</tr>
<tr>
<td>Woodwaste</td>
<td>628</td>
<td>1,255</td>
<td>1,883</td>
</tr>
<tr>
<td>Small-Medium Hydro</td>
<td>628</td>
<td>1,255</td>
<td>1,883</td>
</tr>
<tr>
<td>Total</td>
<td>1,883</td>
<td>3,766</td>
<td>5,649</td>
</tr>
<tr>
<td>Avg. Generation Cost (¢ / kWh)</td>
<td>5.5</td>
<td>5.5</td>
<td>5.5</td>
</tr>
<tr>
<td>Capital Cost of Transmission</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>(million 2001 Cdn $, undiscounted)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Seventh Cable</td>
<td>168</td>
<td></td>
<td></td>
</tr>
<tr>
<td>D-S Reinforcements</td>
<td>56</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New Substation</td>
<td></td>
<td>78a</td>
<td></td>
</tr>
</tbody>
</table>

*a This investment is actually assumed to occur in 08/09 but is shown in 09/10 here for simplicity.

In the GSX-CCGT scenario described above, the initial capacity of the pipeline is fully devoted to electricity generation. We understand, however, that BC Hydro does not rule out the possibility of constructing only one medium-sized CCGT on VI, with additional CCGT generation occurring elsewhere in BC. We have addressed this option through our analysis as well.

Under LOW-EM-IPP, low emission resources are developed and utilized throughout BC to a level that allows the same amount of electricity to be provided to VI as under GSX-CCGT. Because LOW-EM-IPP requires large-scale transmission from the mainland, transmission losses of 7% were factored into the portfolio. As with GSX-CCGT, we assume that the generation resources are added in three equal increments, in fiscal years 04/05, 06/07 and 09/10. Each addition of generation potential is composed of 1/3 cogeneration, 1/3 woodwaste and 1/3 small-medium hydro. In order to continue to meet capacity requirements on VI under LOW-EM-IPP, the transmission link to the mainland is enhanced by adding a seventh, spare phase cable to the existing Malaspina – Dunsmuir 500 kV circuits.2

2 This was the transmission option used for portfolio analysis in BC Hydro’s 1995 IEP (see p. 7-9). We chose to rely on the 1995 IEP because it contains the only publicly available, fully detailed explanation of the transmission options that has been obtained from Hydro. Other preferred configurations are not significantly different in terms of NPV.
Base Case Results

Our results in the base case are shown in Table ES-2. Unit electricity costs are higher under LOW-EM-IPP, but the difference between the two portfolios is barely distinguishable when it comes to residential rates. The LOW-EM-IPP rate is less than 1% higher than the GSX-CCGT rate. Compared to GSX-CCGT, LOW-EM-IPP results in an increase in annual electricity costs of about $3.40 for the average residential customer (an increase of 28 cents per month).

Table ES-2: Summary of GSX-CCGT and LOW-EM-IPP Base Case Results

<table>
<thead>
<tr>
<th></th>
<th>GSX-CCGT</th>
<th>LOW-EM-IPP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit Electricity Cost (¢ / kWh)</td>
<td>5.95</td>
<td>6.57</td>
</tr>
<tr>
<td>Residential Rate in BC (¢ / kWh)</td>
<td>6.65</td>
<td>6.69</td>
</tr>
<tr>
<td>CO\textsubscript{2}E Emissions, 2010 (Mtonnes)</td>
<td>1.85</td>
<td>0.19</td>
</tr>
<tr>
<td>Cost of CO\textsubscript{2}E Reductions ($ / tonne)</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>NO\textsubscript{X} Emissions to GB, 2010 (tonnes)</td>
<td>174</td>
<td>9</td>
</tr>
<tr>
<td>VI Capacity Self-Sufficiency, 2010</td>
<td>54%</td>
<td>31%</td>
</tr>
</tbody>
</table>

As a contrast, in its interim report of November 2001, the provincial Task Force on Energy Policy recommended a move to rates that reflect market prices, indicating a 30% increase over the current rate of 6.5 ¢ / kWh to 8.4 ¢ / kWh. Figure ES-1 compares GSX-CCGT and LOW-EM-IPP rates with the rate suggested by the Task Force.

Figure ES-1: Comparison of Residential Electricity Rates to 2010
Under GSX-CCGT, the 5,280 GWh of electricity generated on VI in the year 2010 results in 1.85 Megatonnes of CO$_2$e emissions. Current annual emissions from the entire BC Hydro system are only about 2 Mt CO$_2$e. LOW-EM-IPP delivers the same amount of electricity to the Island in 2010 with emissions of only 0.19 Mt, a reduction of 1.66 Mt relative to GSX-CCGT. Figure ES-2 shows approximate CO$_2$e emissions from electricity generation in BC under the two portfolios. LOW-EM-IPP also performs better in terms of NO$_X$ emissions. Emissions to the Georgia Basin are only 9 tonnes in 2010, a reduction of 165 tonnes from the 174 tonnes emitted by GSX-CCGT.

**Figure ES-2: Comparison of CO$_2$e Emissions from Electricity in BC to 2010**

![Graph showing CO$_2$e emissions comparison]

We estimate the cost of the emission reductions realized in moving from GSX-CCGT to LOW-EM-IPP to be $20 per tonne CO$_2$e. This makes LOW-EM-IPP one of the cheapest options available to Canada for reducing greenhouse gas (GHG) emissions. Figure ES-3 shows a cost curve for emission reductions in Canada estimated as part of the National Climate Change Process, and indicates how the base case costs of LOW-EM-IPP compare with other options for emission reduction.
We used the capacity self-sufficiency of VI as a measure of electricity security. Under GSX-CCGT, we estimate that in 2010 54% of the peak capacity demand on VI will be met by generation located on the Island itself. On-Island generation would supply only 31% of total capacity requirements in 2010 under LOW-EM-IPP (about the same as the current situation).

In the case where a single CCGT is installed on VI, and additional CCGT generation occurs elsewhere in BC, we found the unit electricity cost to be 6.30 ¢ / kWh. This does not compare well with the GSX-CCGT base case where three CCGTs are located on VI (5.95 ¢ / kWh). We therefore reject the one-CCGT option and do not include it in our risk analysis.
**Risk Analysis**

Our risk analysis takes into account uncertainty around three key parameters: capital cost of GSX, CCGT generation cost (as influenced by natural gas prices) and cost of the transmission upgrade. We examined how these uncertainties affect unit electricity costs. The first two parameters impact the unit cost of GSX-CCGT, while the last parameter impacts the cost of LOW-EM-IPP.

The results of our risk analysis are depicted in Figure ES-4. Unit electricity cost is presented as a continuous probability distribution for both GSX-CCGT and LOW-EM-IPP. We have indicated our base case cost estimates with dashed arrows.

**Figure ES-4: Electricity Cost Probability Distributions, GSX-CCGT and LOW-EM-IPP**

![Electricity Cost Probability Distributions](image)

We observe a significant degree of overlap between the distributions. This indicates it is quite possible that LOW-EM-IPP will be as cheap or cheaper than GSX-CCGT, given the uncertainties that exist. The skew in the GSX-CCGT distribution, combined with its relatively large spread, suggests that the probability of high electricity costs is greater under this portfolio.
Preliminary Trade-Off Analysis

Table ES-3 summarizes our results in the form of a matrix. A preliminary trade-off analysis suggests that LOW-EM-IPP is preferable to GSX-CCGT as an energy strategy for BC. The alternative portfolio provides important environmental and job creation benefits at a financial cost very similar to that of GSX-CCGT, and with less risk.

Table ES-3: Trade-Off Matrix

<table>
<thead>
<tr>
<th>Attribute</th>
<th>GSX-CCGT</th>
<th>LOW-EM-IPP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Financial</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Unit Electricity Cost</td>
<td>Slightly better – if no pipeline cost overruns and gas prices low</td>
<td>Slightly poorer - may end up better depending on pipeline and natural gas costs</td>
</tr>
<tr>
<td>• Rate Impact</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Environmental</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• GHG / CO₂e</td>
<td>Poorer</td>
<td>Much better</td>
</tr>
<tr>
<td>• NOₓ</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• VI Electricity Security</td>
<td>Better</td>
<td>Same as now</td>
</tr>
<tr>
<td>• Job Creation</td>
<td>Less; Limited to Vancouver Island</td>
<td>Greater; Province-wide</td>
</tr>
<tr>
<td>• Risks</td>
<td>Greater electricity cost risk (impacts on rates and / or gov’t); Exposure to GHG cost risk</td>
<td>Less electricity cost risk (risks to ratepayers less if IPPs); Minimizes GHG cost risk</td>
</tr>
</tbody>
</table>

This analysis had a limited scope, and as researchers we did not have access to all the relevant information. Our preliminary work, however, highlights the need for further clarification and examination of the assumptions behind recent planning decisions made by BC Hydro, and demonstrates the value of considering alternatives to a GSX-CCGT path.
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Introduction

Background

The generation of electricity is associated with serious environmental threats, including smog, acid rain, climate change, loss of biodiversity from flooding and river disruption, and nuclear radiation. As concerns for these threats mounted in the 1970s and 1980s, policy makers responded by requiring electricity production monopolies (electric utilities) to conduct multi-attribute trade-off analyses (MATA) to evaluate alternative generation and end-use efficiency investments in terms of their financial, environmental and social attributes. Because public values are critical in such evaluations, the MATA included direct public involvement, usually in stakeholder consultative processes. Risk analysis was also a significant aspect. The common electricity industry name for its application of MATA is integrated resource planning (IRP). The overall impact of IRP has been to increase utility investment in energy efficiency and environmentally desirable generation technologies like cogeneration, wind, small hydro, biomass and solar.

Over the last few decades, another important trend has emerged within the electricity industry. Technological, regulatory and market changes have reversed the relative cost advantage of large generation plants and thus undermined the rationale for electricity production monopolies. Since 1990, a growing number of governments have dismantled their generation monopolies and opened the market to competition. In concert with this, most have enacted policies to address the environmental threats that IRP – a monopoly investment planning tool – could no longer consider. Almost all countries provide grants and tax credits to renewable technologies. England (1990) established a fixed wires charge on all consumers to generate revenue for renewables support. California (1996) included a similar charge to support renewables and efficiency programs. Many countries and individual states, such as Denmark (1997) and Texas (1999), enacted renewable portfolio standards to guarantee a growing market share for these technologies. Norway (1993) and other European countries established carbon taxes. The U.S. government (1990) applied a sulfur cap and tradable permit system to the electric sector.

Today, therefore, most jurisdictions in OECD countries have either an electricity monopoly that still conducts IRP for regulatory review, or a competitive market with policies that increase the market share of environmentally friendly generation by independent power producers (IPPs). In British Columbia, however, BC Hydro is a state-owned monopoly that since the late 1990s is effectively exempted from the IRP requirements of the BC Utilities Commission.

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1 Cogeneration is the combined production of useful heat and electricity. Compared to stand-alone thermal systems, cogeneration requires less fuel per unit of energy output. The process therefore increases efficiency and can reduce air emissions from what they otherwise would be.
BC Hydro’s Natural Gas Strategy (GSX-CCGT)

In its integrated electricity plan (IEP) of 2000, BC Hydro presented a supply expansion of 900 MW for the period 2001 – 2010 of which 83% would be developed by themselves or the Columbia Power Corporation (another state-owned entity) and the remainder (180 MW) by IPPs focused on renewable energy sources. BC Hydro’s IEP is dominated by one or several combined cycle gas turbine plants (CCGT) on Vancouver Island (VI), fed by a new natural gas pipeline called the Georgia Strait Crossing (GSX). The proposed pipeline would provide transport from the Sumas / Huntingdon supply hub in Washington State, connecting with the existing Centra Gas transmission system on VI (see Figure 1). For convenience, we refer to Hydro’s investment plan as GSX-CCGT.

Electricity generated by facilities on Vancouver Island (VI) accounts for only 20% of electricity consumed. The remaining 80% is delivered from the mainland by three submarine cable transmission systems: two 500 kV circuits, a high-voltage direct current (HVDC) system and two 138 kV circuits (Figure 1). These systems are aging; the 138 kV cables are no longer being used to serve VI and the HVDC link is expected to be completely retired in 2007. This erosion in transmission capability combined with an increase in demand on the Island has provided part of the rationale for the GSX-CCGT strategy. There are, however, other options available.

In developing their most recent electricity plan, BC Hydro did not conduct an IRP, at least not in the sense described above. An acceptable range of generation, demand-side and transmission resource options was not addressed in its IEP: non-natural gas alternatives to GSX-CCGT were not considered, cogeneration retrofits were overlooked as an option for new supply and there was no testing of different levels of effort in electricity efficiency. There was no public involvement in order to assess values about intangible factors and trade-offs. There was no explicit risk analysis. Hydro maintains, however, that it is “one of only a handful of companies and organizations on this planet who have actively committed to balancing social, economic and environmental considerations in everything they do.”

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4 A CCGT uses the exhaust gases from a turbine to turn a generator directly and to heat water into steam that turns a second generator. These two steps explain the term combined-cycle. Although the turbine could burn various fuels, natural gas is the dominant energy source.
5 BC Hydro website: News / Georgia Strait Crossing Project <eww.bchydro.bc.ca/articles/gsx>
6 BC Hydro, 1995 Integrated Electricity Plan, Appendix H, pp. 42 and 43.
7 BC Hydro, 2000 IEP, pp. 15 and 16.
8 BC Hydro website: News / Georgia Strait Crossing Project
To carry out its GSX-CCGT strategy, BC Hydro has made applications to the National Energy Board for the pipeline and is seeking a site for its first CCGT plant on Vancouver Island. These actions have been met with concern from environmentalists, the public at large, independent power producers and independent analysts, such as ourselves, who are intent on the application of transparent and effective decision analysis processes to important choices within the public and private sectors. In this study, we report on our effort to conduct a simple MATA process that addresses some of the important issues that were overlooked in BC Hydro’s latest IEP.
Low Emission IPP Alternative (LOW-EM-IPP)

The first step in conducting a MATA is to establish objectives that will guide the process. We found the planning objectives expressed by BC Hydro on page 18 of its 2000 IEP to be equally applicable to our own analysis:

To provide the best electricity solutions for current and future generations of British Columbians in an environmentally and socially responsible manner.

- Minimize the cost of electricity services to customers
- Provide reliable supply that meets customer needs and expectations
- Minimize adverse and promote positive environmental impacts
- Provide positive socio-economic benefits in B.C.
- Promote implementation of appropriate new and existing technologies

With these objectives in mind, we developed an alternative to GSX-CCGT that we refer to as the Low Emission IPP (LOW-EM-IPP) portfolio. LOW-EM-IPP provides a useful contrast to GSX-CCGT for decision-makers to consider. It involves replacing and increasing transmission capacity to VI, and allowing independent power producers (IPPs) to develop low emission resources such as cogeneration, woodwaste and small-medium hydro throughout the province. These resources have positive environmental attributes and are low in cost relative to other environmentally desirable technologies.

GSX-CCGT and LOW-EM-IPP differ in two fundamental respects.

1. Transmission type: Under GSX-CCGT, energy is delivered to VI in the form of natural gas through a new pipeline, while under LOW-EM-IPP energy is delivered in the form of electricity through an upgraded submarine cable system.

2. Generation location and ownership: Under GSX-CCGT, electricity is generated on Vancouver Island by BC Hydro and perhaps a private partner using CCGT technology, while under LOW-EM-IPP electricity is generated throughout BC using low emission resources developed by IPPs.

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9 In this analysis, we use the term cogeneration to refer to retrofits to systems that already burn natural gas (and other fossil fuels) to generate heat. Once a retrofit has occurred, the additional fuel needed to generate electricity is small relative to what was already required by the heating system. This means that the air emissions associated with the electricity production are quite low. Heating systems that could be targeted for cogeneration retrofits include those that exist in hospitals, universities, commercial buildings, industry and institutional buildings.

10 Because trees absorb CO$_2$ during their growing cycles, net CO$_2$ (and greenhouse gas) emissions are considered to be zero when woodwaste is burnt to generate electricity. The impact of woodwaste combustion on local air pollution varies by project. In cases where the wood residue was previously disposed of in open-air burners, local air quality will improve substantially with diversion to a modern biomass electricity generation plant.

11 In this study we have not, therefore, considered other renewables such as wind, tidal, solar and geothermal.
The Analysis

After developing our alternative portfolio, we specified a series of attributes or criteria by which to evaluate GSX-CCGT and LOW-EM-IPP. Ultimately, the purpose of this evaluation is to determine which portfolio best meets the overall objectives. We assessed the options in terms of two financial attributes, unit electricity costs and impact on residential electricity rates, and two environmental attributes, CO$_2$e and NO$_X$ emissions. The cost of CO$_2$e emission reduction was calculated by combining financial and environmental information. We also considered electricity security on VI. Job creation was assessed in a qualitative manner.

In order to conduct our analysis, we required financial and technical information, not only for the present, but also for years far into the future (up to 2025). Although it is impossible to know with certainty the value for each parameter in an exercise such as this, we used the available data and literature (primarily from BC Hydro), as well as expert opinion to derive a set of “most likely” assumptions. We refer to this collection of parameter values as our base case.

Despite our efforts to construct the most realistic base case possible, a great deal of uncertainty remains with respect to some of our key parameters. The previous pipeline to VI had a large construction cost overrun. Improving electricity transmission capacity to the Island may prove more expensive than expected. Natural gas prices have fluctuated substantially over the past 24 months, as have long-term forecasts.

The presence of uncertainty indicates that there are risks associated with GSX-CCGT and LOW-EM-IPP that are not reflected in our base case results. We therefore conducted a risk analysis of the two portfolios with respect to unit electricity costs. As a result, we are able to characterize each portfolio in terms of a range of potential electricity cost outcomes, each with a probability attached.

In summary, there are five steps to the MATA process that we followed.

1. Establish objectives
2. Identify alternatives
3. Specify attributes
4. Evaluate alternatives
   (in terms of attributes and risk profile)
5. Select preferred option

The balance of this report elaborates further on the nature of the alternatives considered, and outlines the methodology associated with and the results obtained in step 4. Finally, some conclusions may be drawn about which is the better electricity option for BC.

Unfortunately, we did not have the resources and access to information necessary to provide the extensive analysis that would issue from a full IRP process. In particular, we regret that we were unable to incorporate public consultation into the exercise. This
preliminary work, however, highlights the need for further clarification and examination of the assumptions behind recent planning decisions made by BC Hydro, especially given its stated commitment to balance economic, social and environmental considerations in everything it does.
Methodology

GSX-CCGT: Base Case Assumptions

The GSX pipeline is expected to be in-service in October 2004\(^\text{12}\) and has been designed to initially deliver 99,175 GJ of natural gas each day.\(^\text{13}\) This is enough gas to power three 220 MW CCGTs on the Island, producing a total of 5,280 GWh per year.\(^\text{14}\)

In the base case, we assume that the pipeline will be used to its full capacity, given the large sunk cost associated with the investment. We also assume that there will be negligible non-electricity consumption of the pipeline gas. While this latter assumption can certainly be challenged, there is substantial evidence in its favor.

- Without dramatic economic growth on VI over the next 3-6 years, new residential and commercial buildings are unlikely to absorb much of the pipeline’s capacity for natural gas space heating and appliance applications. Yet job losses from government downsizing and forest sector restructuring are expected to be particularly pronounced on the Island, and recent economic evidence has borne this out.

- Much of the easiest retrofit of existing buildings to natural gas occurred in the period immediately after completion of the first pipeline to VI in 1991. Further conversions are more costly and require action from people who are less willing to make the switch – perhaps because of a preference for electric, wood or oil heating or higher than average costs for gas connection.

- Subsidy programs for conversions to natural gas have been cut back.

- Government subsidies that guaranteed natural gas’ price advantage over home heating fuel have been eliminated. Recent dramatic fluctuations in the price of natural gas have made potential consumers well aware of the price risks of natural gas.

Table 1 shows the number of commercial and residential gas customers on VI and the Sunshine Coast over the past decade. Growth rates are falling rapidly, as residential and commercial markets become saturated and subsidies are removed. Figure 2 depicts this decline, evidence that there will be negligible growth in natural gas demand for end-use applications over the next several years.

\(^{12}\) Georgia Strait Crossing Project website: Project Information \(<\text{www.georgiastrait.twc.com/project_info.htm}>\)

\(^{13}\) Georgia Strait Crossing Pipeline Limited, Application to the National Energy Board for a Certificate of Public Convenience and Necessity, April 2001, Volume No. II, p. 2-1. With extra compression, capacity could be increased to 150-200 TJ / day. Therefore, the GSX pipeline could ultimately contribute to much more natural gas-based electricity generation on VI than we are assuming here, with greater impacts in terms of plant siting and cumulative emissions.

\(^{14}\) Assuming that the CCGTs are 52.5% efficient, and that they have a capacity factor of 92.4%.
Table 1: Number of Natural Gas Customers on VI and Sunshine Coast – Year End

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>7,446</td>
<td>14,225</td>
<td>23,620</td>
<td>32,542</td>
</tr>
<tr>
<td>Growth over Previous Yr.</td>
<td></td>
<td>91%</td>
<td>66%</td>
<td>38%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>33,490</td>
<td>40,614</td>
<td>48,099</td>
<td>53,542</td>
<td>58,136</td>
<td>61,234</td>
</tr>
<tr>
<td>Commercial</td>
<td>6,080</td>
<td>6,653</td>
<td>7,159</td>
<td>7,610</td>
<td>8,181</td>
<td>8,231</td>
</tr>
<tr>
<td>Total</td>
<td>39,570</td>
<td>47,267</td>
<td>55,258</td>
<td>61,152</td>
<td>66,317</td>
<td>69,465</td>
</tr>
<tr>
<td>Growth over Previous Year</td>
<td>22%</td>
<td>19%</td>
<td>17%</td>
<td>11%</td>
<td>8%</td>
<td>5%</td>
</tr>
</tbody>
</table>

Figure 2: Annual Growth Rates in Residential and Commercial Gas Customers

BC Hydro is both a pipeline proponent and a potential pipeline customer. As a proponent, it will be in Hydro’s best interests to see the capacity of the pipeline fully utilized, ensuring the economic viability of the project. Given the factors listed above that reduce the other likely demands for natural gas, Hydro may have a difficult time diverting the outflow towards non-electricity uses. As a potential customer, it will be tempted to respond by siting electricity generation on Vancouver Island regardless of the outcome of its own IRP processes.

Our base case GSX-CCGT portfolio includes three 220 MW CCGT facilities built in stages on VI, with the first one in-service in fiscal year 04/05, the second in 06/07 and the third in 09/10. Each CCGT produces 1,760 GWh / year, resulting in 5,280 GWh
BC’s Electricity Options

generated in 09/10. The cost of the pipeline has been estimated at $260 million by BC Hydro.\textsuperscript{15} We assume the levelized cost of electricity generation\textsuperscript{16} using CCGT technology to be 5.3 \( \epsilon \) / kWh.\textsuperscript{17} These assumptions, along with the base case assumptions for LOW-EM-IPP are summarized later on in Table 2.

\textbf{GSX-CCGT: One CCGT on VI}

BC Hydro has not committed to a strategy of fully utilizing the capacity of the pipeline for electricity generation, and continues to explore the possibility of constructing only one medium-sized CCGT on VI, with additional CCGT generation occurring elsewhere in BC.\textsuperscript{18} Figure 3 uses a decision tree to illustrate both possibilities. The tree contains two square decision nodes, the first representing the choice between GSX-CCGT and LOW-EM-IPP and the second representing the choice between building one or three CCGTs on VI if the GSX-CCGT path is taken.

\textbf{Figure 3: Decision Tree, Number of CCGTs on VI}

<table>
<thead>
<tr>
<th>Electricity Portfolio</th>
<th>Number of CCGTs on VI</th>
</tr>
</thead>
<tbody>
<tr>
<td>GSX-CCGT</td>
<td>3 VI CCGTs</td>
</tr>
<tr>
<td>LOW-EM-IPP</td>
<td>1 VI CCGT</td>
</tr>
</tbody>
</table>

We explored the possibility that only one (240 MW) CCGT might be built on VI by calculating the unit cost of electricity under this scenario. The full cost of the GSX pipeline was not applied to the cost of electricity. We assumed that, in the absence of full-scale CCGT generation on the Island, it would be possible to divert some of the

\begin{itemize}
  \item \textsuperscript{15} BC Hydro website: News / Georgia Strait Crossing Project
  \item \textsuperscript{16} For the purpose of this analysis, generation costs include plant costs and fuel costs, but not pipeline (or, in the case of LOW-EM-IPP, transmission) costs.
  \item \textsuperscript{17} Sources tell us that this is a value frequently used by BC Hydro based on its long-term forecasts of natural gas prices.
  \item \textsuperscript{18} See BC Hydro’s 2000 IEP, chapter 6.
\end{itemize}
pipeline’s remaining capacity to residential and commercial applications. The cost of this portion of capacity was removed from the unit electricity cost calculation.

A transmission upgrade to the mainland would be required around fiscal year 07/08 if only one CCGT were built on VI. We assumed the same strategy for improving transmission capacity as under LOW-EM-IPP (see below). The capital costs of the transmission upgrade are incurred later, however, since siting one CCGT on the Island would alleviate somewhat the need for increased capacity. All other assumptions were the same as in the GSX-CCGT base case.

LOW-EM-IPP: Base Case Assumptions

Under LOW-EM-IPP, retrofit cogeneration, woodwaste and small-medium hydro resources are developed and utilized throughout BC to a level that allows the same amount of electricity to be provided to VI as under GSX-CCGT. This results in more capacity being installed than under GSX-CCGT because a CCGT has a higher capacity factor than do low emission resources such as small hydro. GSX-CCGT generates electricity on VI, while LOW-EM-IPP requires large-scale transmission from the mainland. Transmission losses must therefore be factored into the LOW-EM-IPP portfolio. We assume an overall loss of 7%, meaning that 7% more electricity is generated under this portfolio than under GSX-CCGT.

As with GSX-CCGT, we assume that the generation resources are added in three equal increments, in fiscal years 04/05, 06/07 and 09/10. In each of these years, approximately 1,883 GWh / year of energy are added until the resource totals 5,649 GWh / year in 09/10. Each addition of generation potential is composed of 1/3 cogeneration, 1/3 woodwaste and 1/3 small-medium hydro, giving a total of 1,883 GWh / year for each of the individual resources in 09/10.

We calculated an average generation cost for LOW-EM-IPP resources based on the amount of energy produced in 09/10. For woodwaste and small-medium hydro (3766 GWh in 09/10), we assumed a cost of 5 ¢ / kWh for the first 1950 GWh and 5.5 ¢ / kWh for the remainder. For cogeneration (1883 GWh in 09/10), we assumed a cost of 6 ¢ / kWh. This gives a weighted average cost of generation of approximately 5.5 ¢ / kWh in the base case.

---

19 Natural gas demand in the commercial and residential sectors on VI was forecast based on recent sales data from the existing pipeline operated by Centra Gas (see Table 1 and Figure 2).
20 Our source for woodwaste and small-medium hydro is Marvin Shaffer and Associates, Constable Associates Consulting and Alchemy Consulting, Multiple Account Benefit-Cost Evaluation of the Burrard Thermal Generating Plant, April 2001, p.50. The information in that report was compiled using data from BC Hydro as well as other sources. Our source for cogeneration is Hagler Bailley Canada, Potential for Cogeneration in Ontario, for the Ontario Ministry of Energy Science and Technology, 2000, p.10 and 12. The cogeneration technologies used will be primarily aeroderivative turbines and reciprocating turbines (1-6 MW) and gas turbine plants (30 MW) all applied as retrofits to thermal applications in existing facilities. The two studies referenced above provide estimates for the quantities of generation resources available at certain price levels.
In order to continue to meet capacity requirements on VI under LOW-EM-IPP, the transmission link to the mainland is enhanced by adding a seventh, spare phase cable to the existing Malaspina – Dunsmuir 500 kV circuits.\textsuperscript{21} The capital cost is about $300 million and includes the cost of the seventh cable ($168 million), reinforcements to the Dunsmuir to Sahtlam transmission system ($56 million) and a new 500 kV substation in the Nanaimo area ($78 million).\textsuperscript{22} We assume that the seventh cable will be in-service in 04/05, the same year that the pipeline is completed under GSX-CCGT. The substation is built four years after the addition of the seventh cable.

The transmission upgrade does not necessarily need to be undertaken in 04/05. By developing LOW-EM-IPP resources (especially cogeneration) on the Island, it might be possible to defer it for several years. Demand side management policies could have a similar impact. It is even possible that the capabilities of the existing cable systems have been underestimated. Because the discounting formula is used when calculating the costs of alternative electricity portfolios (to allow for comparison of costs occurring in different time periods), delays in incurring the capital costs associated with the transmission upgrade would lower the cost of LOW-EM-IPP. In order to take a conservative approach, however, we do not include this possibility in our analysis.

\textsuperscript{21} This was the transmission option used for portfolio analysis in BC Hydro’s 1995 IEP (see p. 7-9). We chose to rely on the 1995 IEP because it contains the only publicly available, fully detailed explanation of the transmission options that has been obtained from Hydro. More recently, other strategies for undersea cable upgrades have been presented as being preferable. For example, in a presentation to the Victoria Chamber of Commerce on March 13, 2002, Shawn Thomas, a Senior Vice-President at BC Hydro, suggested repair / replacement of the HVDC cables (at a cost of $230 million), as well as transmission upgrades on the mainland ($50 million). The NPV of this configuration is very similar to that of the seventh 500 kV cable option.

\textsuperscript{22} Cost estimates for these components were taken from BC Hydro’s 1995 IEP, Appendices E (p. 9-11) and G (pp. 6 and 7). We have converted from $1995 to $2001.
Table 2: Summary of GSX-CCGT and LOW-EM-IPP Base Case Assumptions

<table>
<thead>
<tr>
<th></th>
<th>04/05a</th>
<th>06/07</th>
<th>09/10</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>GSX-CCGT</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of CCGTs on VI</td>
<td>1</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>Total CCGT Capacity (MW)</td>
<td>220</td>
<td>440</td>
<td>660b</td>
</tr>
<tr>
<td>Generation (GWh)</td>
<td>1,760</td>
<td>3,520</td>
<td>5,280</td>
</tr>
<tr>
<td>CCGT Generation Cost (¢ / kWh)</td>
<td>5.3</td>
<td>5.3</td>
<td>5.3</td>
</tr>
<tr>
<td>Capital Cost of GSX (million 2001 Cdn $, undiscounted)</td>
<td>260</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>LOW-EM-IPP</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generation (GWh)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(7% added for transmission losses)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cogeneration</td>
<td>628</td>
<td>1,255</td>
<td>1,883</td>
</tr>
<tr>
<td>Woodwaste</td>
<td>628</td>
<td>1,255</td>
<td>1,883</td>
</tr>
<tr>
<td>Small-Medium Hydro</td>
<td>628</td>
<td>1,255</td>
<td>1,883</td>
</tr>
<tr>
<td>Total</td>
<td>1,883</td>
<td>3,766</td>
<td>5,649</td>
</tr>
<tr>
<td>Avg. Generation Cost (¢ / kWh)</td>
<td>5.5</td>
<td>5.5</td>
<td>5.5</td>
</tr>
<tr>
<td>Capital Cost of Transmission (million 2001 Cdn $, undiscounted)</td>
<td></td>
<td>78c</td>
<td></td>
</tr>
<tr>
<td>Seventh Cable</td>
<td>168</td>
<td></td>
<td></td>
</tr>
<tr>
<td>D-S Reinforcements</td>
<td>56</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New Substation</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* Under both GSX-CCGT and LOW-EM-IPP, the earliest capacity additions to the VI system occur in 04/05. There is some indication that there may be a shortfall before then, due to the fact that the Vancouver Island Cogeneration Project is currently operating below capacity because of constraints on natural gas supply. This situation might be remedied by applying an interruptible tariff to either electricity sales or gas sales. Regardless, the capacity shortfall will be eliminated in 04/05 by either portfolio. In the case of GSX-CCGT, this would be accomplished through an increase in gas supply from GSX and in the case of LOW-EM-IPP, by the increase in transmission capacity. We do not delve further into this issue because if a shortfall does occur, it will impact both of the portfolios that we are evaluating.

* To put this number in perspective, the generation capacity of the BC system used for meeting domestic demand is 12,000 MW.

* This investment is actually assumed to occur in 08/09 but is shown in 09/10 here for simplicity.

**Unit Cost of Electricity and Impact on Rates**

The financial costs of the two portfolios are expressed by folding generation and infrastructure (pipeline, transmission improvements) costs into a single unit cost of electricity. In order to calculate the total cost associated with a portfolio, we started by multiplying its generation cost by the amount of electricity generated. This was done for each year out to 2025. In years where a capital cost is also incurred, this cost was added to the generation costs. The cost in each year was then discounted to 2001, using a discount rate of 10%, and costs over time were added together. To convert to unit costs, we divided by the amount of electricity provided to VI up to 2025, with electricity discounted in the same way as costs.

Rate impacts for residential customers in the BC Hydro service area were also estimated. The current rate is about 6.5 ¢ / kWh. Of this, about 3 ¢ is associated with generation
costs. We estimated what rates would be under GSX-CCGT and under LOW-EM-IPP by assuming that for each portfolio 660 MW of generation capacity will be added to the existing 12,000 MW of BC capacity that is used for meeting domestic demand. In the case of the extra 660 MW, however, generation costs are set at the unit costs referred to above instead of at 3 ¢ / kWh.

**Air Emissions**

CO$_2$e and NO$_X$ emissions were calculated over time for GSX-CCGT and LOW-EM-IPP by applying emission factors to the electricity generated. The emission factors for each generation resource are shown in Table 3. Emissions associated with pipeline transport of natural gas were not added to the GSX-CCGT portfolio.

Our NO$_X$ calculation addresses emissions within the Georgia Basin only. We did not attribute any NO$_X$ emissions to woodwaste because we assume all woodwaste development occurs outside the Georgia Basin. We calculated NO$_X$ emissions from cogeneration using the emission factor in Table 3, but then counted only half of these because we assume that half of the cogeneration retrofits are located outside the Georgia Basin.

<table>
<thead>
<tr>
<th>Generation Resource</th>
<th>CO$_2$e (tonnes / GWh)</th>
<th>NO$_X$ (kg / GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCGT$^a$</td>
<td>350</td>
<td>33</td>
</tr>
<tr>
<td>Small-Medium Hydro</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Woodwaste</td>
<td>0$^b$</td>
<td>NA</td>
</tr>
<tr>
<td>Gas Cogeneration Retrofits</td>
<td>100$^c$</td>
<td>9$^d$</td>
</tr>
</tbody>
</table>

$^a$ Emission factors for CCGT technology are from BC Hydro’s 2000 IEP, p. 23.
$^b$ Recall that CO$_2$e is absorbed during the growing cycle of trees.
$^d$ We derived our NO$_X$ emission factor for cogeneration by applying the relationship observed between CO$_2$e emissions for CCGT and cogeneration (about 3 to 1) to NO$_X$ emissions for the two technologies.

To estimate the cost per tonne of reducing CO$_2$e emissions under LOW-EM-PP, the reductions associated with this portfolio relative to GSX-CCGT were calculated in each year to 2025. These were then discounted to 2001 at a rate of 10% and summed. Finally, the increased total cost of LOW-EM-IPP over GSX-CCGT was divided by the total emission reductions.

---

24 We set generation costs equal to unit costs for the additional 660 MW despite the fact that our unit costs include pipeline and transmission costs. These additional cost elements must be taken into account for a fair comparison of the options.
25 Some analysts estimate the cost per tonne of emission reductions using a methodology that discounts costs only, leaving emissions undiscounted. This would generate lower costs of emission reduction than we estimate here.
**Risk Analysis**

Our risk analysis takes into account uncertainty around three key parameters: capital cost of GSX, CCGT generation cost (as influenced by natural gas prices) and cost of the transmission upgrade. We examined how these uncertainties affect unit electricity costs. The first two parameters impact the unit cost of GSX-CCGT, while the last parameter impacts the cost of LOW-EM-IPP.

Figure 4 adds three uncertainty nodes to the tree from Figure 3, each representing an uncertain parameter. Three potential states of nature – low, base case and high – are associated with each parameter. There is a probability (P) attached to each state of nature. The various combinations of decisions and states of nature result in a range of electricity cost outcomes.

**Figure 4: Decision Tree, Risk Analysis**

Table 4 shows discrete probabilities for each of the branches in the decision tree of Figure 4. The probabilities are based on historical data, and adjusted from discussions with experts. Our analysis is constructed so that other values can quickly be tested. The discrete probabilities can also be converted into continuous probability distributions for the range of possible values for the uncertain parameters. This leads to the calculation of probability distributions around the unit electricity costs for the two options.
<table>
<thead>
<tr>
<th>Uncertain Parameter</th>
<th>State of Nature</th>
<th>Probability of State of Nature</th>
<th>Value of Parameter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost of GSX</td>
<td>High</td>
<td>25%</td>
<td>$390 million (50% increase from base case)</td>
</tr>
<tr>
<td></td>
<td>Base Case</td>
<td>60%</td>
<td>$260 million</td>
</tr>
<tr>
<td></td>
<td>Low</td>
<td>15%</td>
<td>$208 million (20% decrease from base case)</td>
</tr>
<tr>
<td>CCGT Generation Cost</td>
<td>High Natural Gas Prices</td>
<td>20%</td>
<td>5.7 ¢ / kWh</td>
</tr>
<tr>
<td></td>
<td>Base Case</td>
<td>60%</td>
<td>5.3 ¢ / kWh</td>
</tr>
<tr>
<td></td>
<td>Low Natural Gas Prices</td>
<td>20%</td>
<td>4.9 ¢ / kWh</td>
</tr>
<tr>
<td>Cost of Transmission Upgrade</td>
<td>High</td>
<td>20%</td>
<td>$218 + $73 + $102 million (30% increase from base case)</td>
</tr>
<tr>
<td></td>
<td>Base Case</td>
<td>60%</td>
<td>$168 + $56 + $78 million</td>
</tr>
<tr>
<td></td>
<td>Low</td>
<td>20%</td>
<td>$134 + $45 + $63 million (20% decrease from base case)</td>
</tr>
</tbody>
</table>
Results and Discussion

Base Case

Table 5 summarizes our results in the base case. Unit electricity costs are representative of the electricity generated under each of the portfolios; they do not apply to the province-wide electricity system. The estimated rates pertain to all residential customers within the BC Hydro service area. Unit electricity costs are higher under LOW-EM-IPP, but the difference between the two portfolios is barely distinguishable when it comes to residential rates. The LOW-EM-IPP rate is less than 1% higher than the GSX-CCGT rate. Compared to GSX-CCGT, LOW-EM-IPP results in an increase in annual electricity costs of about $3.40 for the average residential customer (an increase of 28 cents per month).

Table 5: Summary of GSX-CCGT and LOW-EM-IPP Base Case Results

<table>
<thead>
<tr>
<th></th>
<th>GSX-CCGT</th>
<th>LOW-EM-IPP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit Electricity Cost (¢ / kWh)</td>
<td>5.95</td>
<td>6.57</td>
</tr>
<tr>
<td>Residential Rate in BC (¢ / kWh)</td>
<td>6.65</td>
<td>6.69</td>
</tr>
<tr>
<td>CO₂e Emissions, 2010 (Mtonnes)</td>
<td>1.85</td>
<td>0.19</td>
</tr>
<tr>
<td>Cost of CO₂e Reductions ($ / tonne)</td>
<td></td>
<td>20</td>
</tr>
<tr>
<td>NOₓ Emissions to GB, 2010 (tonnes)</td>
<td>174</td>
<td>9</td>
</tr>
<tr>
<td>VI Capacity Self-Sufficiency, 2010</td>
<td>54%</td>
<td>31%</td>
</tr>
</tbody>
</table>

As a contrast, the provincial Task Force on Energy Policy has recommended a move to rates that reflect market prices, indicating a 30% increase over the current rate of 6.5 ¢ / kWh to 8.4 ¢ / kWh. Figure 5 compares GSX-CCGT and LOW-EM-IPP rates with the rate suggested by the Task Force.

Under GSX-CCGT, the 5,280 GWh of electricity generated on VI in the year 2010 results in 1.85 Megatonnes of CO₂e emissions. Current annual emissions from the entire BC Hydro system are only about 2 Mt CO₂e. LOW-EM-IPP delivers the same amount of electricity to the Island in 2010 with emissions of only 0.19 Mt, a reduction of 1.66 Mt relative to GSX-CCGT. Figure 6 shows approximate CO₂e emissions from electricity generation in BC under the two portfolios. LOW-EM-IPP also performs better in terms of NOₓ emissions. Emissions to the Georgia Basin are only 9 tonnes in 2010, a reduction of 165 tonnes from the 174 tonnes emitted by GSX-CCGT.

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26 Based on an annual consumption of 10,344 kWh / year for the average residential customer. Henry Mak, BC Hydro Load Forecasting, personal communication, February 12, 2002.
28 BC Hydro. “Meeting Vancouver Island’s Electricity Needs.” September 2000, p.3.
29 This despite the fact that more electricity is generated under LOW-EM-IPP (because transmission losses must be made up).
We estimate the cost of the emission reductions realized in moving from GSX-CCGT to LOW-EM-IPP to be $20 per tonne CO$_2$e. This makes LOW-EM-IPP one of the cheapest options available to Canada for reducing greenhouse gas (GHG) emissions.

Had we not discounted emission reductions, our cost per tonne would have been $6.
Figure 7 shows a cost curve for emission reductions in Canada estimated as part of the National Climate Change Process (NCCP), and indicates how the base case costs of LOW-EM-IPP compare with other options for emission reduction. Our results suggest that LOW-EM-IPP will actually be the more cost-effective portfolio under almost any scenario of a concerted national effort to reduce GHG emissions. GSX-CCGT, on the other hand, represents a commitment to emissions over at least a 30-year time frame.

**Figure 7: Cost Curve for GHG Emission Reductions in Canada, 2010**

We used the capacity self-sufficiency of VI as a measure of electricity security. Under GSX-CCGT, we estimate that in 2010 about 54% of the peak capacity demand on VI will be met by generation located on the Island itself. On-Island generation would supply only about 31% of total capacity requirements in 2010 under LOW-EM-IPP (about the same as the current situation). While LOW-EM-IPP leaves the Island more dependent on electricity from the mainland, both options still require substantial electricity imports to Vancouver Island. As for energy independence, the GSX-CCGT option requires transmission of natural gas from the mainland.

---

GSX-CCGT: One CCGT on VI

We found the unit electricity cost of GSX-CCGT to be 6.30 ¢ / kWh when only one CCGT is installed on VI. This compares to a cost of 5.95 ¢ / kWh in the base case (three CCGTs installed). The one-CCGT option is more expensive because the full capacity of GSX is not utilized, with the cost of the unused portion being allocated to the cost of electricity. Another factor contributing to higher costs is the investment in transmission capacity to the mainland that must be made in addition to building the pipeline. Because of its increased cost relative to the three-CCGT base case, we do not include the option of only one CCGT plant on VI as part of our risk analysis.

Risk Analysis

The results of our risk analysis are depicted in Figure 8. Unit electricity cost is presented as a continuous probability distribution for both GSX-CCGT and LOW-EM-IPP. We have indicated our base case cost estimates with dashed arrows.

Figure 8: Electricity Cost Probability Distributions, GSX-CCGT and LOW-EM-IPP

LOW-EM-IPP has a higher base case cost estimate (6.57 ¢ / kWh) than GSX-CCGT (5.95 ¢ / kWh). The GSX-CCGT distribution is wider than the LOW-EM-IPP distribution, however, indicating that there is a greater degree of uncertainty associated with the outcome of the former portfolio. The LOW-EM-IPP distribution is symmetrical because we assumed that the probability of the actual cost being below the base case is equal to the probability of the actual cost being above the base case. The GSX-CCGT distribution is skewed to the right, because historical evidence shows a greater probability of natural gas pipelines relative to electricity transmission lines costing higher than the anticipated. The shape of the GSX-CCGT distribution contributes to a significant degree
of overlap with LOW-EM-IPP. The skew in the GSX-CCGT distribution, combined with its relatively large spread, indicates that the probability of high electricity costs is greater under this portfolio.

**Preliminary Trade-Off Analysis**

Table 6 summarizes the results of our analysis in the form of a matrix. This presentation highlights the trade-offs involved in choosing between GSX-CCGT and LOW-EM-IPP. Electricity costs are slightly lower with GSX-CCGT in the base case. However, the degree of overlap in the probability distributions around unit electricity costs for the two portfolios, as revealed by our risk analysis, indicates it is quite possible that LOW-EM-IPP will be as cheap or cheaper than GSX-CCGT, given uncertainties around pipeline cost, natural gas prices and transmission costs. The low cost of CO₂ reductions under LOW-EM-IPP suggests that it will be the more cost effective portfolio under almost any scenario involving significant constraints on GHG emissions.

**Table 6: Trade-Off Matrix**

<table>
<thead>
<tr>
<th>Attribute</th>
<th>Portfolio</th>
<th>GSX-CCGT</th>
<th>LOW-EM-IPP</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Financial</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Unit Electricity Cost</td>
<td></td>
<td>Slightly better – if no pipeline cost overruns and gas prices low</td>
<td>Slightly poorer - may end up better depending on pipeline and natural gas costs</td>
</tr>
<tr>
<td>• Rate Impact</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Environmental</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• GHG / CO₂e</td>
<td></td>
<td>Poorer</td>
<td>Much better</td>
</tr>
<tr>
<td>• NOₓ</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• VI Electricity Security</td>
<td></td>
<td>Better</td>
<td>Same as now</td>
</tr>
<tr>
<td>• Job Creation</td>
<td></td>
<td>Less; Limited to Vancouver Island</td>
<td>Greater; Province-wide</td>
</tr>
<tr>
<td>• Risks</td>
<td></td>
<td>Greater electricity cost risk (impacts on rates and / or gov’t); Exposure to GHG cost risk</td>
<td>Less electricity cost risk (risks to ratepayers less if IPPs); Minimizes GHG cost risk</td>
</tr>
</tbody>
</table>

With respect to air emissions (our indicators of environmental performance) LOW-EM-IPP is a much better choice. Electricity security for VI customers is superior with GSX-CCGT, however, as measured by capacity self-sufficiency.

In terms of job creation, past experience shows that smaller electricity generation units are more labor intensive. GSX-CCGT limits jobs to pipeline construction and then the construction and operation of a few large plants on VI. LOW-EM-IPP opens the entire province to entrepreneurial activity by IPPs. The provincial distribution and total amount of jobs with LOW-EM-IPP is likely to be substantially greater than with GSX-CCGT, but only through a macro-economic analysis can the number be estimated.
Electricity and GHG cost risks are lower with LOW-EM-IPP. Under GSX-CCGT, there is a risk of high electricity costs if pipeline construction is over budget and natural gas prices are higher than expected. The burden of these costs will either be passed on to BC electricity customers through higher rates; or to government, and thereby BC taxpayers, because of lower returns from BC Hydro, a crown corporation. The electricity cost risk associated with LOW-EM-IPP is mostly due to uncertainty around the cost of replacing transmission to VI. If there is some uncertainty around the cost of generation with this portfolio, it is less of a concern for ratepayers. This is because IPPs that make what turn out to be high-cost investments lose money for their shareholders, not ratepayers. GSX-CCGT, with its high GHG emissions, puts BC at risk of incurring large mitigation costs in the future.

Given the wide band of uncertainty around electricity cost estimates, as well as the large cost risk associated with GSX-CCGT, we do not consider the small improvement in financial performance associated with this portfolio in the base case to constitute an advantage over LOW-EM-IPP. The only other attribute where GSX-CCGT demonstrates superiority is electricity supply security to VI. However, while more electricity will be generated on VI, this option still involves bringing energy to the Island, this time in the form of natural gas instead of electricity. Additional analysis should assess the relative risks of failure to undersea natural gas pipelines and undersea electricity transmission cables. Given that the costs and security outcomes of the two options are so similar, it is striking to note the dramatically superior ranking of the LOW-EM-IPP option in terms of GHG and NOx emissions. One would have to value this environmental advantage at zero in order to prefer GSX-CCGT to LOW-EM-IPP. This is a troubling finding, given BC Hydro’s stated commitment to balancing financial, social and environmental objectives in everything it does.
Conclusions

This analysis compared BC Hydro’s current natural gas generation strategy (GSX-CCGT) with an alternative provincial portfolio involving the development of low emission generation capacity by IPPs (LOW-EM-IPP). We employed a simple MATA process, evaluating the two portfolios on the basis of unit electricity costs, impact on residential electricity rates, magnitude of CO$_2$e and NO$_X$ emissions, electricity security on VI and job creation. We also calculated the cost of CO$_2$e emission reduction. Because we were dealing with several highly uncertain parameters, we conducted an analysis of the financial cost risks associated with both GSX-CCGT and LOW-EM-IPP.

We found the two portfolios to be very similar in terms of costs. GSX-CCGT results in slightly lower costs in the base case; however the cost estimates are uncertain and there are serious cost risks associated with this portfolio. GSX-CCGT is superior in terms of electricity supply security to VI, but LOW-EM-IPP is associated with significant environmental and job creation benefits. Our preliminary trade-off analysis suggests that LOW-EM-IPP is preferable to GSX-CCGT as an energy strategy for BC.

We found LOW-EM-IPP to be the better option despite the fact that we were quite conservative in our assumptions concerning the two portfolios. We relied on BC Hydro’s own data wherever possible and tended to err to the advantage of GSX-CCGT. We chose not to defer the transmission upgrade under LOW-EM-IPP, either by situating the first capacity additions on the Island itself, or by simulating demand side management programs. We did not call into question BC Hydro’s load forecast, despite indications that it may be inflated given recent trends of economic recession and downsizing within the public sector -- not to mention the softwood lumber issue. Although the costs of alternative generation technologies are expected to fall with increasing market share, we did not incorporate this process into our analysis. Finally, the monetary values of human and environmental damages were not accounted for.

This analysis had a limited scope, and as researchers we did not have access to all the relevant information. A more involved study would be indicated prior to embarking on a LOW-EM-IPP strategy for BC. However, we believe we have demonstrated the value of considering alternatives to the GSX-CCGT path, especially given the risks to which BC customers are exposed under this option.
Appendix: Questions and Answers

This appendix addresses frequently heard questions with respect to the GSX-CCGT strategy as well as alternative, low emission electricity options for BC.

Financial

Q. Don’t we need to move ahead quickly with GSX-CCGT because Vancouver Island will soon be short of electricity?

A. The forecast of VI electricity demand growth was made prior to the latest economic downturn and the decision to eliminate about 6,000 public sector jobs on VI over the next three years. Electricity demand is closely tied to economic activity. If, however, VI electricity demand does keep growing at the earlier forecast rate, extra time for proper decision making can be bought at low cost by offering short-term interruptible rates for large electricity customers on VI and fostering some micro-cogeneration on VI (which can be brought on line quickly). This is preferable to rushing into a major decision without fully and openly considering the alternatives.

Q. Doesn’t replacing 5,300 GWh / year from GSX-CCGT with small-medium hydro, woodwaste and cogeneration throughout BC exceed the provincial potential, at reasonable cost, for these resources?

A. No. The quantities and prices used in this study for these three resources are conservative estimates derived mainly from BC Hydro sources. The prices for each have been adjusted upward to be even more conservative. In most studies, but not this one, costs of these new, environmentally desirable technologies are shown to decline with application and time, meaning significantly lower costs by 2010. But in this study, the costs are not reduced, again to be conservative.

Q. What are the impacts on electricity rates of LOW-EM-IPP relative to GSX-CCGT?

A. Because the financial costs of the two options are very close, the rate impact is close to zero and may even be negative. Under base case assumptions, LOW-EM-IPP leads to a rate increase over GSX-CCGT of less than 1% over the period to 2010 (cost is estimated at less than $5 / year for a typical residential customer). Indeed, there is perhaps a 40% chance that LOW-EM-IPP will result in lower rates than GSX-CCGT, due to:

1. Pipeline cost overruns,
2. Average natural gas prices higher than US $3.30 / MMBTU,
3. A small externality charge applied to CO₂ emissions beginning some time in the next 20 years (as already exists in many countries in Europe today),
(4) A small externality charge applied to NOx emissions beginning some time in the next 20 years (as already exists in southern California today with the RECLAIM program), and

(5) A decline in the cost of woodwaste and small hydro electricity relative to CCGT (as is happening with most new, renewable technologies).

Moreover, the base case upward effect on rates of less than 1% is undetectable when contrasted with the 30% rate increase proposed by the Energy Task Force in order to have BC Hydro’s average prices reflect market prices.

Q. BC Hydro states that renewables like wind, solar, tidal and geothermal are still in early stages of development and would be relatively high cost to implement in BC today. Isn’t this true?

A. Yes. That is why the alternative proposed here is limited to woodwaste, small-medium hydro and cogeneration, all of which have substantial potential today in BC at competitive costs. It would be valuable, however, to explore the implications (cost, economic development) of a requirement that the LOW-EM-IPP option include, by 2010, 10% of new generation from the cheapest combination of wind, solar, tidal and geothermal.

Environmental

Q. Shouldn’t environmental objectives be explicitly considered when addressing energy supply options?

A. Yes. The Premier has explicitly committed to this for his government. At a luncheon at the Canadian Institute of Energy in November 2000, Gordon Campbell said: “We recognize that in today’s world, it’s the government’s job to ensure our energy industry is encouraged to grow in ways that minimize environmental impact. Clean air, clean water, environmental sustainability are not political options. They are ecological, economic and social obligations. They are economic, social and environmental musts. A BC Liberal government will not compromise those environmental values for short-term gains.”

Q. Shouldn’t BC take actions now to reduce GHG emissions?

A. It depends. The important thing to understand is that any energy decision today has risks. If high costs are incurred to reduce GHG emissions too soon, these may be regretted later. For example, it would be difficult to justify shutting down the Burrard Thermal plant in order to reduce GHG or NOx emissions when there are much cheaper alternatives. However, there is substantial risk in bypassing low or negative cost opportunities to reduce GHG emissions today. GSX-CCGT and LOW-EM-IPP are almost identical financially, which means that opting for GSX-CCGT results in bypassing an easy opportunity to reduce the risk of future GHG related costs to the economy, perhaps substantial ones. We have to decide why we would want to take that risk.
Q. Aren’t there cheaper ways to reduce GHG emissions in BC and Canada?

A. Commissioned research for the National Climate Change Process indicates that Canada needs to reduce emissions by over 200 Mt CO$_2$e from what they otherwise would be in 2010, in order to reach the Kyoto commitment that is 6% below its 1990 emissions and of which the marginal cost is over $150 / t CO$_2$e. Further negotiations now allow Canada to achieve much of its target by purchasing reductions in other countries, which will lower the national cost (marginal and total). However, low cost domestic options – lower than $50 / t CO$_2$e may be cost competitive with foreign purchases and will be preferable from an economic development perspective (domestic investment and jobs). Under most assumptions, the cost of switching from GSX-CCGT to LOW-EM-IPP will be below $20 / t CO$_2$e and may even be profitable. This is consistent with other national and international research that consistently shows most of the cheapest GHG reduction actions to be in the electricity sector. Finally, the GSX-CCGT project will continue long after the period covered by the Kyoto protocol. In the next few years, international negotiations will begin for reduction commitments in the post-2010 period. If the international community decides to slow further the growth of atmospheric concentrations of GHGs, reduction levels and the corresponding costs will be significantly higher. This means that GSX-CCGT has a substantial risk that its CO$_2$e emissions after 2010 will have a significantly higher cost associated with them.

Q. Aren’t there cheaper ways to reduce NOx emissions in the Georgia Basin?

A. As with CO$_2$e, because the GSX-CCGT and the LOW-EM-IPP are very similar in cost, the effective cost of NOx reduction is close to zero, making this one of the cheapest ways of advancing local air quality objectives, whether in the Georgia Basin with NOx or in interior communities with particulates from beehive burners. Actions such as this are generally easier from both an economic and policy perspective; many of the other opportunities for NOx reduction involve significant changes in the investments and behaviour of vehicle users, which is obviously more challenging.

Social and Economic Development

Q. Why not build GSX while pursuing BC Hydro’s proposal to pay someone (by purchasing emission credits) in another country to reduce GHG emissions?

A. Under the base case assumptions, this option may be slightly cheaper financially (although GSX-CCGT and LOW-EM-IPP cost about the same in the base case scenario), but it is costly in terms of economic development and environmental quality in BC. Purchasing reductions outside of BC reduces economic development in BC, transferring money and jobs outside the province. In its Feb.5, 2002 submission to the BC Energy Policy Task Force, the Independent Power Association of BC said: “Rather than BC Hydro purchasing GHG credits abroad, it should purchase electricity from the new green and clean independent power producers in BC.” In support of this position, the IPABC quotes the BC Liberal Party’s New Era policy statement that: “A BC Liberal Government
will encourage job creation from viable independent power production projects that will increase benefits to consumers through greater competition.” From an environmental perspective, the LOW-EM-IPP project will not just decrease GHG emissions, but also NOx and particulate emissions in the Georgia Basin and particulate emissions to a significant degree in those interior communities that replace beehive burners with clean burning woodwaste generators.

Q. Why is smaller size cogeneration (small industrial, commercial, institutional, municipal waste, residential) in the LOW-EM-IPP proposal when it is almost non-existent for the next 10 years of BC Hydro’s integrated electricity plan?

A. This is a surprising aspect of BC Hydro’s integrated electricity plan. Cogeneration, of all sizes, has played a dominant role in electricity generation investment in OECD countries over the last decade and is expected to be even more significant in the next decade. In his address to the Canadian Institute of Energy in November 2000, Gordon Campbell said: “We can do much more with co-generation throughout the province. I want to help make that happen.”

Q. Won’t extra gas to VI be needed in any case?

A. At some time in the future, this is possible. However, if LOW-EM-IPP better satisfies the province’s multiple objectives today, GSX can be delayed for a decade or more. At that future time, many parameters may have changed. Hydrogen pipelines may be preferred for example. Also, commercial and residential natural gas demand on VI should not increase, and may even decrease, in the next few years given expected economic conditions. The owners of the first natural gas pipeline found it very difficult to get VI consumers to switch to natural gas and this endeavor will be especially challenging during an economic downturn, and given consumer awareness of extremely high natural gas prices in the winter of 2000 / 2001. The possibility that electricity generation is the only major consumer of the gas increases the risks of the pipeline.

Q. Isn’t it true that the GSX creates jobs?

A. Focusing on employment can be misleading because what counts for economic growth is productivity gain – which results from the profitability of investments. Because GSX-CCGT and LOW-EM-IPP are about the same cost in the base case, both would have the same effect on long run productivity and economic growth in the province, if risks were neutral. However, the previous pipeline, after construction cost overruns and subsidies to VI gas consumers in order to increase gas volumes, cost the provincial economy in the range of $100 million. GSX has some risk in this direction, although perhaps not of the same magnitude. If one’s focus is jobs, past experience shows that smaller electricity generation units are more labor intensive. GSX-CCGT limits jobs to pipeline construction and then the construction and operation of a few large plants on VI. LOW-EM-IPP opens the entire province to entrepreneurial activity by independent power producers (some of it attracting foreign investment). The provincial distribution and total
amount of jobs with LOW-EM-IPP is likely to be substantially greater than with GSX-CCGT, but only through a macro-economic analysis can the number be estimated.

More Effective Government

Q. How does GSX-CCGT fit in with the government’s policy toward regulation of BC Hydro?

A. The Premier has promised to bring BC Hydro back under the control of the BC Utilities Commission. In his address to the Canadian Institute of Energy in November, 2000 he stated: “It’s critical that we restore the independence of the Utilities Commission to properly do its job on behalf of utilities and consumers alike without political interference. We intend to do that.” However, if BC Hydro is brought under commission regulation after GSX-CCGT has begun, it will be too late for the informed debate about energy resource options in a way that fully accounts for environmental imperatives that the premier has called for elsewhere.

Q. There has been no formal opportunity for public debate about BC Hydro’s 2000 Integrated Electricity Plan, in which GSX-CCGT is promoted. Then, in its interim report, the Energy Policy Task Force accepted with only one page of discussion Hydro’s “decision” to build GSX. Is this consistent with the government’s position on developing energy policy?

A. In his November, 2000 address to the Canadian Institute of Energy, Gordon Campbell stated: “I want to make it clear, we can’t come to a sound public policy decision without open public debate with regard to those energy options that are in front of us. There is no question that we would all benefit publicly from having a full, open public discussion and forum to learn about different perspectives, so we can set some public goals, public objectives and public responses and create the energy benefit that we should have.”

Q. How does GSX-CCGT fit in with the government’s policy on BC Hydro’s structure and its role in provincial electricity generation?

A. The government’s pre-election policy statements suggest a small or zero role for BC Hydro in developing new electricity generation and the Energy Task Force suggests splitting BC Hydro into three divisions. However, if GSX goes ahead, conventional pipeline economics will pressure BC Hydro to develop quickly generation capacity on VI in order to spread the fixed costs of the pipeline over a significant volume of gas flow. Because of this, Hydro is likely to be involved in a significant share of provincial generation expansion over the coming decade, as is already evident from its current efforts to site a 250 MW facility. If the government intends to split Hydro into generation, transmission and distribution companies over the next few years, it must decide what to do with the pipeline. Electricity transmission and distribution companies do not own natural gas pipelines. If the government later decides to privatize the pipeline, and if bids are below book value, the government will incur the financial losses.
Q. Isn’t natural gas generation (GSX-CCGT) on VI the least risky option?

A. No. From the perspective of the physical security of energy delivery, natural gas pipelines and undersea electricity cables do not differ significantly. However, the first VI pipeline ran significantly over cost. If this occurs with GSX-CCGT, either BC’s taxpayers will lose because of lower returns from BC Hydro or BC’s ratepayers will lose because of higher rates; government policy will decide which occurs. Natural gas prices may average a higher level than forecast; again, either BC taxpayers or ratepayers face this risk. Finally, environmental charges could be levied against GHG or NOx emissions, which would materialize as a cost to BC taxpayers or ratepayers.